		PLANT						unit)					@ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	11/29/2005	32.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	11/29/2005	18	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	11/29/2005	18	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	11/29/2005	13.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	12/13/2006	35	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	12/13/2006	36.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	12/12/2006	18.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	12/12/2006	18.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	1/9/2008	32	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	OIL FUEL
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	NOX	2/8/2008	21.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	12/7/2004	0.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	2/7/2005	4.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	test on oil at peak load....test at base load 4.7pp nat gas peak 7.4ppm...base load 13.5
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	11/29/2005	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	peak load on oil
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	11/29/2005	3.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	12/13/2006	1.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	12/12/2006	7.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	12/12/2006	2.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050003	CHARLES LARSEN MEMORIAL POWER PLANT	SWD	POLK	A	Y	8	Simple and Combined Cycle CTs (Phase II Acid Rain unit)	A	CO	12/13/2006	2.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Catalyst Air Management
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	CO	12/10/2004	0.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	NOX	3/20/2007	6.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	NOX	6/4/2003	6.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	DID NOT OPERATE IN THIS MODE >400 H
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	NOX	3/18/2004	6.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	NOX	12/10/2004	6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	CO	3/20/2007	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	CO	3/18/2004	0.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	oxidation catalyst in operation
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rain Unit)	A	CO	5/14/2003	0.22	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	NOX	7/7/2006	0.42	POUNDS PER BILLION BTU HEAT INPUT	RATA-
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/17/2005	0.00001	POUNDS PER MILLION BTU HEAT INPUT	DID NOT OPERATE IN THIS MODE >400 H
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/15/2005	0.28	POUNDS PER MILLION BTU HEAT INPUT	DID NOT OPERATE IN THIS MODE >400 H
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	PM	6/14/2007	0.07	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND	1050004	C.D. MCINTOSH, JR.	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG	A	PM	6/15/2005	0.08	POUNDS PER MILLION BTU	

ELECTRIC		POWER PLANT						(Phase II Acid Rain Unit)					HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/12/2007	0.207	POUNDS PER MILLION BTU HEAT INPUT	sootblowing
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/21/2006	0.13	POUNDS PER MILLION BTU HEAT INPUT	Catalyst Air Management, Inc. SOOT BLOWI
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	SO2	6/12/2003	0.47	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	SO2	6/17/2005	0.66	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	SO2	6/9/2004	0.57	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	SO2	1/18/2007	0.57	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	SO2	7/7/2006	0.43	POUNDS PER MILLION BTU HEAT INPUT	determined during RATA testing
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/12/2003	0.51	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/17/2005	0.48	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/9/2004	0.26	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	NOX	1/18/2007	0.51	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	NOX	7/7/2006	0.42	POUNDS PER MILLION BTU HEAT INPUT	determined during RATA testing
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	NOX	10/2/2007	0.324	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	SO2	7/7/2006	0.43	POUNDS PER MILLION BTU HEAT INPUT	RATA
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	6/9/2004	0.03	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	1/18/2007	0.028	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/6/2003	0.086	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/6/2003	0.15	POUNDS PER MILLION BTU HEAT INPUT	sootblow
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/21/2005	0.095	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/21/2005	0.127	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/3/2004	0.068	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/3/2004	0.079	POUNDS PER MILLION BTU HEAT INPUT	sootblowing
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/21/2006	0.072	POUNDS PER MILLION BTU HEAT INPUT	Catalyst Air Management, Inc. STEADY STA
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	6/9/2003	0.04	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	1/1/2005	0.0001	POUNDS PER MILLION BTU HEAT INPUT	oil/refuse/petcoke not burned
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	1/1/2005	0.0001	POUNDS PER MILLION BTU HEAT INPUT	oil/refuse/petcoke not burned
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	1/1/2005	0.0001	POUNDS PER MILLION BTU HEAT INPUT	oil/refuse/petcoke not burned
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	6/17/2005	0.02	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	6/17/2005	0.0001	POUNDS PER MILLION BTU HEAT INPUT	fuel not burned
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	6/17/2005	0.00001	POUNDS PER MILLION BTU HEAT INPUT	DID NOT OPERATE IN THIS MODE >400 H
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	PM	6/17/2005	0.00001	POUNDS PER MILLION BTU HEAT INPUT	DID NOT OPERATE IN THIS MODE >400 H
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	A	PM	6/17/2007	0.088	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	PM	5/30/2003	0.08	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	PM	6/8/2004	0.05	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	A	CO	10/2/2007	0.0105	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	NOX	5/30/2003	0.29	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/8/2004	0.28	POUNDS PER MILLION BTU HEAT INPUT	
LAKELAND ELECTRIC	1050004	C.D. MCINTOSH, JR. POWER PLANT	SWD	POLK	A	Y	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	A	NOX	6/14/2007	0.25	POUNDS PER MILLION BTU HEAT INPUT	

CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	13	Two existing peel dryers w/ five WHEs	I	PM	1/17/2006	6.5	POUNDS/HOUR	dryer #2
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	13	Two existing peel dryers w/ five WHEs	I	PM	1/24/2005	16.066	POUNDS/HOUR	Dryer#1 10.462 lb/hr and Dryer #2 5.604lb/hr
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	1	No. 1 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	A	PM	1/18/2008	7.9	POUNDS/HOUR	ATC
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	1	No. 1 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	A	PM	1/16/2003	7	POUNDS/HOUR	50.5 tons/hr
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	3	No. 2 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	A	PM	1/22/2007	3.337	POUNDS/HOUR	atc
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	3	No. 2 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	A	PM	1/17/2003	4.9	POUNDS/HOUR	51.5 tons/hr
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	3	No. 2 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	A	PM	1/16/2008	3.7	POUNDS/HOUR	ATC
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	1	No. 1 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	A	PM	1/22/2007	9.893	POUNDS/HOUR	atc
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	13	Two existing peel dryers w/ five WHEs	I	PM	1/17/2006	1.77	POUNDS/HOUR	dryer #1
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	8	EXISTING COGENERATION SYSTEM #1 W/DUCT BURNER NO.1	A	NOX	1/15/2008	80.87	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	ATC
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	8	EXISTING COGENERATION SYSTEM #1 W/DUCT BURNER NO.1	A	NOX	1/15/2003	88.57	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	9	EXISTING COGENERATION SYSTEM NO. 2 W/DUCT BURNER NO. 2	A	NOX	1/22/2007	118	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	atc
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	9	EXISTING COGENERATION SYSTEM NO. 2 W/DUCT BURNER NO. 2	A	NOX	1/15/2003	81.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	9	EXISTING COGENERATION SYSTEM NO. 2 W/DUCT BURNER NO. 2	A	NOX	2/12/2004	68.66	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	9	EXISTING COGENERATION SYSTEM NO. 2 W/DUCT BURNER NO. 2	A	NOX	1/21/2005	73.98	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	9	EXISTING COGENERATION SYSTEM NO. 2 W/DUCT BURNER NO. 2	A	NOX	1/20/2006	70.71	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	9	EXISTING COGENERATION SYSTEM NO. 2 W/DUCT BURNER NO. 2	A	NOX	1/15/2008	79.96	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	ATC
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	8	EXISTING COGENERATION SYSTEM #1 W/DUCT BURNER NO.1	A	NOX	2/12/2004	76.35	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	8	EXISTING COGENERATION SYSTEM #1 W/DUCT BURNER NO.1	A	NOX	1/22/2007	112	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	ATC
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	8	EXISTING COGENERATION SYSTEM #1 W/DUCT BURNER NO.1	A	NOX	1/20/2006	89.97	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CUTRALE CITRUS JUICES USA,INC	1050023	CUTRALE CITRUS JUICES USA,INC	SWD	POLK	A	Y	8	EXISTING COGENERATION SYSTEM #1 W/DUCT BURNER NO.1	A	NOX	1/21/2005	69.28	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	24	DRY PHOSPHATE ROCK TRANSFER SYSTEM @ NORALYN MINE (024)	A	PM	5/13/2004	1.2	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	13	PHOSPHATE ROCK STORAGE SILOS 1, 2, 3, & 12 @ NORALYN MINE (0	A	PM	5/13/2004	1.1	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	12	PHOSPHATE ROCK DRYER NO. 2 EAST @ NORALYN MINE (012)	A	PM	6/17/2004	27.4	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	12	PHOSPHATE ROCK DRYER NO. 2 EAST @ NORALYN MINE (012)	A	PM	7/30/2003	32.7	POUNDS/HOUR	process rate; 433 tph
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	12	PHOSPHATE ROCK DRYER NO. 2 EAST @ NORALYN MINE (012)	A	PM	6/8/2005	23.5	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN MINE (011)	A	PM	2/8/2006	26	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN MINE (011)	A	PM	2/11/2004	15.4	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN MINE (011)	A	PM	2/14/2003	22.5	POUNDS/HOUR	253 tph
MOSAIC FERTILIZER LLC	1050034	CENTRAL FLORIDA MINERAL OPERATIONS	SWD	POLK	A	Y	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN MINE (011)	A	PM	2/9/2005	13.8	POUNDS/HOUR	
BARTOW CITRUS PRODUCTS, LLC.	1050045	BARTOW CITRUS PRODUCTS, LLC.	SWD	POLK	A	Y	6	2 CITRUS PEEL DRYERS W/WASTE HEAT EVAPORATOR	A	PM	2/5/2008	7.153	POUNDS/HOUR	ATC
BARTOW CITRUS PRODUCTS, LLC.	1050045	BARTOW CITRUS PRODUCTS, LLC.	SWD	POLK	A	Y	6	2 CITRUS PEEL DRYERS W/WASTE HEAT EVAPORATOR	A	PM	1/13/2004	9.95	POUNDS/HOUR	
BARTOW CITRUS PRODUCTS, LLC.	1050045	BARTOW CITRUS PRODUCTS, LLC.	SWD	POLK	A	Y	6	2 CITRUS PEEL DRYERS W/WASTE HEAT EVAPORATOR	A	PM	1/30/2007	11.3	POUNDS/HOUR	atc
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SAM	3/30/2007	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SAM	3/6/2006	0.036	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SAM	2/15/2005	0.022	POUNDS PER TON OF PRODUCT	102.0 tph 100% acid
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SAM	5/21/2003	0.03	POUNDS PER TON OF PRODUCT	95.5 tph
MOSAIC		MOSAIC FERTILIZER -						Wet Process Phosphoric Acid					POUNDS PER	

FERTILIZER, LLC	1050046	BARTOW FACILITY	SWD	POLK	A	Y	10	Plant (NO.4 & NO.5 COMBINED)	A	FL	5/18/2007	0.00026	TON OF FEED MATERIAL	Process Rate 126 TPH
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	10	Wet Process Phosphoric Acid Plant (NO.4 & NO.5 COMBINED)	A	FL	3/12/2004	0.007	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	FL	5/23/2006	0.017	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	FL	3/22/2007	0.028	OTHER (SPECIFY IN COMMENT)	lb/ton p2o5
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SO2	4/21/2003	0.8	POUNDS PER TON OF PRODUCT	95 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SO2	5/21/2003	1.08	POUNDS PER TON OF PRODUCT	95.5 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SO2	3/3/2004	2.6	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SO2	2/15/2005	3.7	POUNDS PER TON OF PRODUCT	102.0 tph 100% acid
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SO2	3/6/2006	3.6	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SO2	3/30/2007	3.7	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	10	Wet Process Phosphoric Acid Plant (NO.4 & NO.5 COMBINED)	A	FL	3/25/2003	0.0101	POUNDS PER TON OF FEED MATERIAL	process rate: 155.6 tons of P2O5
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SAM	3/28/2003	0.036	POUNDS PER TON OF PRODUCT	99 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SAM	3/30/2004	0.029	POUNDS PER TON OF PRODUCT	100 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SAM	4/7/2006	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	NOX	4/25/2003	0.12	POUNDS PER TON OF PRODUCT	103 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SAM	3/14/2003	0.023	POUNDS PER TON OF PRODUCT	process rate: 105 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SAM	3/4/2004	0.036	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SAM	3/4/2004	0.036	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SAM	2/22/2005	0.042	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SAM	3/14/2006	0.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	7/23/2003	0.32	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	7/25/2003	0.055	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	6/3/2005	0.266	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	6/6/2005	0.07	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	5/18/2004	0.07	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	5/23/2006	0.15	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	PM	3/22/2007	0.067	OTHER (SPECIFY IN COMMENT)	lb/ton p2o5
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	54	No. 3 Sulfuric Acid Plant	A	SO2	8/8/2007	2.8	POUNDS PER TON OF PRODUCT	Production Rate: 67.3 TPH (100% Acid)
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SO2	3/28/2003	3.6	POUNDS PER TON OF PRODUCT	99 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SO2	3/30/2004	2.8	POUNDS PER TON OF PRODUCT	100 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SO2	3/1/2005	3.7	POUNDS PER TON OF PRODUCT	production rate: 102.0 TPH 100% Acid)
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	SO2	4/7/2006	3.84	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	FL	6/3/2005	0.02	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	21	No. 4 Fertilizer Plant	A	FL	5/18/2004	0.012	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	10	Wet Process Phosphoric Acid Plant (NO.4 & NO.5 COMBINED)	A	FL	4/28/2006	0.0014	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SAM	4/21/2003	0.034	POUNDS PER TON OF PRODUCT	95 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SO2	2/22/2005	3.87	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SO2	3/14/2006	3.9	POUNDS PER TON OF PRODUCT	
MOSAIC	1050046	MOSAIC FERTILIZER -	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	2/26/2003	0.011	POUNDS PER TON OF FEED	

FERTILIZER, LLC		BARTOW FACILITY											MATERIAL	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	2/25/2004	0.04	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	1/24/2005	0.027	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	1/24/2005	0.027	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	4/20/2006	0.027	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	2/22/2007	0.038	OTHER (SPECIFY IN COMMENT)	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	FL	1/16/2008	0.006	OTHER (SPECIFY IN COMMENT)	lb/ton p2o5
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SO2	3/14/2003	3.6	POUNDS PER TON OF PRODUCT	process rate: 105 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SO2	3/4/2004	1.5	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	33	No. 5 Sulfuric Acid Plant	A	SO2	3/4/2004	1.5	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	32	No. 6 Sulfuric Acid Plant	A	NOX	4/26/2003	0.12	POUNDS PER TON OF PRODUCT	102 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	NOX	4/21/2003	0.1	POUNDS PER TON OF PRODUCT	95 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	NOX	5/21/2003	0.12	POUNDS PER TON OF PRODUCT	95.5 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	12	No. 4 Sulfuric Acid Plant	A	SAM	3/3/2004	0.033	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	2	No. 4 Fertilizer Shipping Plant	A	PM	6/18/2003	0.002	GRAINS PER DRY STANDARD CUBIC FOOT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	2	No. 4 Fertilizer Shipping Plant	A	PM	5/24/2004	0.0001	GRAINS PER DRY STANDARD CUBIC FOOT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	2	No. 4 Fertilizer Shipping Plant	A	PM	7/6/2005	0.003	GRAINS PER DRY STANDARD CUBIC FOOT	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	10	Wet Process Phosphoric Acid Plant (NO.4 & NO.5 COMBINED)	A	FL	4/21/2005	1.11	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	1/24/2005	5.37	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	2/25/2004	4.95	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	2/26/2003	3.94	POUNDS/HOUR	process rate: 112 tph
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	1/24/2005	5.37	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	4/20/2006	5.07	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	1/16/2008	3.6	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050046	MOSAIC FERTILIZER - BARTOW FACILITY	SWD	POLK	A	Y	1	No. 3 Fertilizer Plant	A	PM	2/22/2007	5.16	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050048	MOSAIC FERTILIZER - MULBERRY FACILITY	SWD	POLK	I	Y	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGN	I	SAM	2/17/2006	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050048	MOSAIC FERTILIZER - MULBERRY FACILITY	SWD	POLK	I	Y	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGN	I	SO2	2/17/2006	3.6	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050048	MOSAIC FERTILIZER - MULBERRY FACILITY	SWD	POLK	I	Y	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGN	I	SO2	2/1/2005	3	POUNDS PER TON OF PRODUCT	production rate: 63 tph 100% acid (1512 tpd)
MOSAIC FERTILIZER, LLC	1050048	MOSAIC FERTILIZER - MULBERRY FACILITY	SWD	POLK	I	Y	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGN	I	SO2	2/4/2004	3.8	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050048	MOSAIC FERTILIZER - MULBERRY FACILITY	SWD	POLK	I	Y	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGN	I	SAM	2/4/2004	0.024	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050048	MOSAIC FERTILIZER - MULBERRY FACILITY	SWD	POLK	I	Y	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGN	I	SAM	2/1/2005	0.021	POUNDS PER TON OF PRODUCT	production rate: 63 tph 100% acid (1512tpd)
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	PM	8/8/2005	14.4	POUNDS/HOUR	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	FL	8/5/2003	0.008	POUNDS PER TON OF FEED MATERIAL	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	FL	5/11/2004	0.005	POUNDS PER TON OF FEED MATERIAL	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	FL	8/5/2003	0.008	POUNDS PER TON OF FEED MATERIAL	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	PM	8/5/2003	6.9	POUNDS/HOUR	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	PM	8/5/2003	6.9	POUNDS/HOUR	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	FL	8/8/2005	0.016	POUNDS PER TON OF FEED MATERIAL	
U S AGRI-CHEMICALS CORP.	1050050	U S AGRI-CHEMICALS - BARTOW	SWD	POLK	I	Y	38	150 TPH MAP/DAP PLANT (79 TPH P2O5 INPUT)	I	PM	5/11/2004	25.5	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	21	PHOSPHORIC ACID PLANT TANK FARM	I	FL	12/1/2004	0.057	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	20	PHOSPHORIC ACID PLANT B-TRAIN	I	FL	12/9/2003	0.0012	POUNDS PER TON OF FEED MATERIAL	Scrubber: 56.1 GPM and 10.4 in H2O pressure

U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	20	PHOSPHORIC ACID PLANT B-TRAIN	I	FL	11/29/2004	0.0009	POUNDS PER TON OF FEED MATERIAL	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	SO2	11/11/2003	3.04	POUNDS PER TON OF PRODUCT	New limit of 106.4 tph results from testing belc 90% of process rate limit.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	SO2	2/11/2003	2.96	POUNDS PER TON OF PRODUCT	Tested at 96.3 tph (77% of permitted process ra New process limit until next test is 105.93 tph.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	SO2	12/7/2004	3.39	POUNDS PER TON OF PRODUCT	94 tph
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	PM	7/1/2004	0.1132	POUNDS PER TON OF PRODUCT	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	NOX	2/26/2003	10.8	PARTS PER MILLION DRY GAS VOLUME	Test team: US Agri-Chem. Operations above ra 2424 TPD will require retest.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	SAM	11/11/2003	0.021	POUNDS PER TON OF PRODUCT	New limit of 106.4 tph results from testing belc 90% of process rate limit.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	SAM	2/11/2003	0.03	POUNDS PER TON OF PRODUCT	Tested at 96.3 tph (77% of permitted process ra New process limit until next test is 105.93 tph.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	SAM	12/7/2004	0.04	POUNDS PER TON OF PRODUCT	94 tph
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	16	SULFURIC ACID PLANT #1	I	NOX	2/25/2003	9.4	PARTS PER MILLION DRY GAS VOLUME	Test team: US Agri-Chem. Operations above ra 2493 TPD will require retest.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	SO2	11/13/2003	3.25	POUNDS PER TON OF PRODUCT	New limit of 104.3 tph results from testing belc 90% of process rate limit.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	SO2	2/13/2003	2.99	POUNDS PER TON OF PRODUCT	Tested at 95.6 tph (76% of permitted process ra New process limit until next test is 105.16 tph.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	SO2	12/9/2004	3.12	POUNDS PER TON OF PRODUCT	94.5 tph
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	FL	9/23/2003	0.018	POUNDS PER TON OF FEED MATERIAL	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	FL	7/1/2004	0.0137	POUNDS PER TON OF FEED MATERIAL	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	5	PHOSPHORIC ACID PLANT A-TRAIN, 50 TPH PROCESS INPUT RATE	I	FL	12/11/2003	0.0004	POUNDS PER TON OF FEED MATERIAL	Scrubber: 38.3 GPM and 10.2 in H2O pressure
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	5	PHOSPHORIC ACID PLANT A-TRAIN, 50 TPH PROCESS INPUT RATE	I	FL	12/2/2004	0.0011	POUNDS PER TON OF FEED MATERIAL	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	SAM	11/13/2003	0.032	POUNDS PER TON OF PRODUCT	New limit of 104.3 tph results from testing belc 90% of process rate limit.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	SAM	2/13/2003	0.042	POUNDS PER TON OF PRODUCT	Tested at 95.6 tph (76% of permitted process ra New process limit until next test is 105.16 tph.
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	17	SULFURIC ACID PLANT #2	I	SAM	12/9/2004	0.038	POUNDS PER TON OF PRODUCT	94.5 tph
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	PM	9/23/2003	0.066	POUNDS PER TON OF PRODUCT	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	21	PHOSPHORIC ACID PLANT TANK FARM	I	FL	12/10/2003	0.055	POUNDS/HOUR	Scrubber: 67.9 GPM and 3.9 in H2O pressure d
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	PM	8/22/2005	6.8	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	FL	9/23/2003	0.45	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	FL	7/1/2004	0.442	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	PM	7/1/2004	6.9	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	PM	9/23/2003	3.1	POUNDS/HOUR	
U.S. AGRI-CHEMICALS CORPORATION	1050051	U.S. AGRI-CHEMICALS - FT. MEADE	SWD	POLK	I	Y	38	Granular MAP/DAP Plant	I	FL	8/22/2005	0.76	POUNDS/HOUR	
CF INDUSTRIES, INC.	1050052	CF INDUSTRIES - BARTOW PHOSPHATE COMPLEX	SWD	POLK	I	Y	6	SULFURIC ACID PLANT NO.6	I	SO2	7/23/2004	0.0001	POUNDS PER TON OF PRODUCT	no test plant not operated per letter
CF INDUSTRIES, INC.	1050052	CF INDUSTRIES - BARTOW PHOSPHATE COMPLEX	SWD	POLK	I	Y	6	SULFURIC ACID PLANT NO.6	I	SAM	7/26/2004	0.00001	POUNDS PER TON OF PRODUCT	no test. plant not operated per letter
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	29	NORTH MAP/DAP FERTILIZER PLANT	A	FL	8/31/2005	0.9778	POUNDS/HOUR	atc
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	PM	4/19/2005	0.0389	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	PM	4/21/2005	0.1318	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	PM	3/15/2006	0.097	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	FL	3/15/2006	0.05	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	29	NORTH MAP/DAP FERTILIZER PLANT	A	FL	9/9/2003	0.002	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	SAM	5/14/2004	0.09	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	SAM	5/4/2005	0.081	POUNDS PER TON OF PRODUCT	
		MOSAIC FERTILIZER -											POUNDS PER	

MOSAIC FERTILIZER, LLC	1050053	GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	SAM	4/10/2003	0.12	TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	SAM	2/22/2005	0.07	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	SAM	7/14/2004	0.08	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	13	PHOSPHORIC ACID PLANT NO. 2 WITH WET SCRUBBER	A	FL	7/31/2003	0.0009	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	13	PHOSPHORIC ACID PLANT NO. 2 WITH WET SCRUBBER	A	FL	12/15/2004	0.001	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	13	PHOSPHORIC ACID PLANT NO. 2 WITH WET SCRUBBER	A	FL	4/15/2005	0.0002	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	13	PHOSPHORIC ACID PLANT NO. 2 WITH WET SCRUBBER	A	FL	11/2/2005	0.0009	POUNDS PER TON OF PRODUCT	ave flow- 115 gpm, fan- 109 amps, H2O pres-
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	SAM	4/30/2003	0.06	POUNDS PER TON OF PRODUCT	process rate: 2130 tpd
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSORPTION	A	SO2	6/10/2003	3	POUNDS PER TON OF PRODUCT	1851 tpd
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSORPTION	A	SO2	4/30/2004	3.5	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSORPTION	A	SO2	9/23/2005	3.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	SO2	4/10/2003	2.2	POUNDS PER TON OF PRODUCT	process rate : 2454 tpd
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	SO2	2/22/2005	3	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	SO2	7/14/2004	3	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	NOX	4/8/2003	0.05	POUNDS PER TON OF PRODUCT	process rate: 2367 tpd
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	NOX	2/22/2005	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	38	2750 TPD No. 6 Sulfuric Acid Plant	A	NOX	7/14/2004	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	NOX	5/14/2004	0.07	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	SO2	5/19/2003	3.7	POUNDS PER TON OF PRODUCT	process rate: 2130 tpd
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	SO2	5/14/2004	3.7	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PLANTS SAP#1 + #2	A	SO2	5/4/2005	3.82	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSORPTION	A	SAM	6/10/2003	0.08	POUNDS PER TON OF PRODUCT	1851 tpd
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSORPTION	A	SAM	4/30/2004	0.07	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSORPTION	A	SAM	9/23/2005	0.071	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	FL	4/19/2005	0.0174	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	FL	4/21/2005	0.0273	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	16	PHOSPHORIC ACID PLANT NO. 1 NORTH TRAIN WITH WET SCRUBBER	A	FL	9/3/2004	0.1	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	16	PHOSPHORIC ACID PLANT NO. 1 NORTH TRAIN WITH WET SCRUBBER	A	FL	12/7/2004	0.47	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	16	PHOSPHORIC ACID PLANT NO. 1 NORTH TRAIN WITH WET SCRUBBER	A	FL	8/15/2003	0.0833	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	17	PHOSPHORIC ACID PLANT NO. 1 SOUTH TRAIN WITH WET SCRUBBER	A	FL	8/22/2003	0.05	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	17	PHOSPHORIC ACID PLANT NO. 1 SOUTH TRAIN WITH WET SCRUBBER	A	FL	8/20/2004	0.17	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	17	PHOSPHORIC ACID PLANT NO. 1 SOUTH TRAIN WITH WET SCRUBBER	A	FL	10/11/2004	0.002	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	17	PHOSPHORIC ACID PLANT NO. 1 SOUTH TRAIN WITH WET SCRUBBER	A	FL	3/24/2006	0.11	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	15	TWO PHOSACID TANKS- 1 CLARIF. & 1 AGING, SCRUBBER N-N	A	FL	11/11/2004	0.014	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	FL	9/11/2003	0.6	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	FL	3/25/2004	0.87	POUNDS/HOUR	
MOSAIC	1050053	MOSAIC FERTILIZER - GREEN BAY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER	A	PM	9/11/2003	2.8	POUNDS/HOUR	

FERTILIZER, LLC		FACILITY						PLANT						
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	7	SOUTH AP FERTILIZER PLANT	A	PM	3/25/2004	7.6	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	14	TWO PHOSACID TANKS (54%),CONTOLLED BY SCRUBBER R-R	A	FL	11/23/2004	0.0242	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	37	FOUR PHOSPHORIC ACID TANKS	A	FL	11/19/2004	0.0001	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	29	NORTH MAP/DAP FERTILIZER PLANT	A	PM	9/9/2003	3.7	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	29	NORTH MAP/DAP FERTILIZER PLANT	A	PM	9/9/2003	3.7	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	29	NORTH MAP/DAP FERTILIZER PLANT	A	PM	8/31/2005	4.6116	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	20	DAP, MAP, OR TSP STORAGE & SHIPPING BUILDINGS	A	PM	6/25/2003	4	POUNDS/HOUR	
MOSAIC FERTILIZER, LLC	1050053	MOSAIC FERTILIZER - GREEN BAY FACILITY	SWD	POLK	A	Y	20	DAP, MAP, OR TSP STORAGE & SHIPPING BUILDINGS	A	FL	6/25/2003	0.1	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	2/21/2006	16	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	12/14/2005	19.91	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	4/27/2004	16.69	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	12/29/2004	17.1	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	11/18/2004	19.8	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	12/13/2005	19.91	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	2/6/2004	11.58	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	24	GTSP East Storage Building - North Scrubber	A	PM	11/5/2003	10.28	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	24	GTSP East Storage Building - North Scrubber	A	PM	8/2/2005	4.24	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	12/13/2005	7.99	POUNDS/HOUR	TEST FAILED -- PERMIT 5.7 LB/HR TEST 7 LB/HR
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	24	GTSP East Storage Building - North Scrubber	A	FL	9/18/2003	3.5	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	24	GTSP East Storage Building - North Scrubber	A	FL	11/5/2003	3.27	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	24	GTSP East Storage Building - North Scrubber	A	FL	8/2/2005	1.3	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	22	No. 2 Ball Mill Grinding System	A	PM	11/19/2003	0.2	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	26	GTSP Rock Hopper Bin	A	PM	1/29/2004	0.29	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	PM	5/2/2003	20.28	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	25	GTSP East Storage Building - South Scrubber	A	PM	9/18/2003	4.32	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	25	GTSP East Storage Building - South Scrubber	A	PM	11/5/2003	10.28	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	25	GTSP East Storage Building - South Scrubber	A	PM	8/2/2005	4.14	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	24	GTSP East Storage Building - North Scrubber	A	PM	9/18/2003	4.32	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	25	GTSP East Storage Building - South Scrubber	A	FL	8/2/2005	0.73	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	25	GTSP East Storage Building - South Scrubber	A	FL	9/18/2003	3.5	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SAM	9/8/2005	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SAM	4/30/2004	0.043	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	NOX	7/13/2004	0.106	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	NOX	3/11/2003	0.116	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	NOX	8/27/2003	0.077	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	NOX	4/30/2004	0.076	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	NOX	9/8/2005	0.1	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	NOX	9/14/2006	0.08	POUNDS PER TON OF PRODUCT	

MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	5/2/2003	0.051	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	2/6/2004	0.025	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	4/27/2004	0.074	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	12/29/2004	0.07	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	11/18/2004	0.05	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	12/14/2005	0.1125	POUNDS PER TON OF FEED MATERIAL	RETEST AFTER FAILURE ON 12/13
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	23	GTSP Production Plant	A	FL	2/21/2006	0.044	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SO2	3/11/2003	3.49	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SO2	5/17/2005	3.79	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SO2	7/13/2004	3.85	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SO2	5/31/2006	3.62	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	9	Phosphoric Acid Plant - B Train	A	FL	1/10/2003	0.00018	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	9	Phosphoric Acid Plant - B Train	A	FL	4/29/2003	0.0047	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	9	Phosphoric Acid Plant - B Train	A	FL	10/7/2005	0.01	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	9	Phosphoric Acid Plant - B Train	A	FL	5/13/2004	0.0023	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	9	Phosphoric Acid Plant - B Train	A	FL	3/2/2006	0.006	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant - A Train	A	FL	1/15/2003	0.004	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant - A Train	A	FL	12/3/2003	0.003	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant - A Train	A	FL	11/24/2004	0.003	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant - A Train	A	FL	2/24/2006	0.004	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant - A Train	A	FL	2/9/2006	0.004	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SAM	3/11/2003	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SAM	5/17/2005	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SAM	7/13/2004	0.032	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	SAM	5/31/2006	0.016	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SO2	4/30/2004	3.73	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SO2	8/27/2003	3.91	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SO2	9/8/2005	3.4	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SO2	9/14/2006	3.5	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	NOX	5/17/2005	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	5	Sulfuric Acid Plant No. 11	A	NOX	5/31/2006	0.079	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SAM	8/27/2003	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 10	A	SAM	9/14/2006	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050055	MOSAIC FERTILIZER - SOUTH PIERCE PLANT	SWD	POLK	A	Y	25	GTSP East Storage Building - South Scrubber	A	FL	11/5/2003	2.52	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	24	AFI Shipping Rail Car Loading	A	PM	3/16/2004	0.07	POUNDS/HOUR	TEST FOR PERMIT RENEWAL ONLY
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	27	AFI Plant	A	PM	3/23/2007	33.6	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	27	AFI Plant	A	PM	5/12/2006	25.2	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	PM	2/23/2006	0.0546	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SAM	2/24/2004	0.028	POUNDS PER TON OF PRODUCT	

MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SAM	9/10/2003	0.03	POUNDS PER TON OF PRODUCT	failed epa audit
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SAM	12/4/2003	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SAM	6/11/2003	0.05	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SAM	11/20/2003	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SAM	12/16/2004	0.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SAM	8/8/2006	0.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SAM	9/19/2007	0.02	POUNDS PER TON OF PRODUCT	ses;
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	5/28/2003	0.188	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	4/23/2004	0.148	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	6/30/2004	0.325	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	9/12/2005	0.32	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	3/1/2006	0.237	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	9/7/2007	0.25	POUNDS PER TON OF FEED MATERIAL	SES
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	FL	10/5/2007	0.25	POUNDS PER TON OF FEED MATERIAL	ses
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant (East)	A	FL	5/10/2004	0.007	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant (East)	A	FL	12/3/2003	0.003	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant (East)	A	FL	3/18/2003	0.006	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SO2	12/15/2005	2.9	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SO2	8/29/2006	3.1	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	NOX	2/24/2004	0.07	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	PM	12/19/2003	0.008	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	PM	2/23/2005	0.0518	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	PM	8/17/2006	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	PM	1/20/2006	0.0162	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	PM	7/12/2007	0	POUNDS PER TON OF PRODUCT	atc 50 tph
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	2/14/2008	0.0417	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	12/10/2003	0.00422	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	3/5/2003	0.003	POUNDS PER TON OF FEED MATERIAL	special test for MACT
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	7/14/2003	0.0107	POUNDS PER TON OF FEED MATERIAL	tested at 58.7 tph p2o5 and 127.1 tph gmap
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	2/1/2005	0.00366	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	6/28/2006	0.0245	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	2/23/2006	0.0012	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	78	GRANULAR MAP PLANT	A	FL	4/5/2007	0.01492	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	3/10/2004	0.037	POUNDS PER TON OF FEED MATERIAL	special engineering test for BACT adjustment
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	1/4/2005	0.01415	POUNDS PER TON OF FEED MATERIAL	0.15 lb pm/hr
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	4/26/2005	0.0305	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	11/17/2004	0.02	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	9/7/2006	0.012	POUNDS PER TON OF FEED MATERIAL	
													POUNDS PER	

MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	8/31/2005	0.00406	TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	10/18/2005	0.033	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	FL	1/11/2007	0.047	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SAM	2/27/2003	0.095	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SAM	6/28/2005	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SAM	7/27/2004	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SAM	6/22/2006	0.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SAM	8/24/2007	0.03	POUNDS PER TON OF PRODUCT	SES, 116 TPH product
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SO2	2/24/2004	3.75	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SO2	9/10/2003	3.25	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SO2	12/4/2003	3.45	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SO2	6/22/2005	3.4	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SO2	8/22/2006	3.5	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SO2	9/6/2007	3.85	POUNDS PER TON OF PRODUCT	ses
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SO2	2/27/2003	2.89	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SO2	6/28/2005	3.25	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SO2	7/27/2004	3.33	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SO2	6/22/2006	3.2	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	SO2	8/24/2007	2.9	POUNDS PER TON OF PRODUCT	ses
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	FL	3/29/2007	0.007	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	3/10/2004	0.1539	POUNDS PER TON OF FEED MATERIAL	engineering test
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	1/4/2005	0.0638	POUNDS PER TON OF FEED MATERIAL	0.67 lb/ton of feed
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	4/26/2005	0.139	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	11/17/2004	0.007	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	9/7/2006	0.63	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	10/18/2005	0.075	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	PM	1/11/2007	0.47	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	17	Phosphoric Acid Plant (West)	A	FL	3/31/2003	0.008	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	FL	1/29/2003	0.024	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	FL	3/30/2004	0.028	POUNDS PER TON OF FEED MATERIAL	GMAP
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	FL	3/3/2005	0.015	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	FL	5/4/2006	0.024	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	17	Phosphoric Acid Plant (West)	A	FL	5/23/2003	0.008	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	17	Phosphoric Acid Plant (West)	A	FL	6/14/2005	0.011	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	17	Phosphoric Acid Plant (West)	A	FL	6/10/2004	0.01049	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	17	Phosphoric Acid Plant (West)	A	FL	11/14/2006	0.018	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	17	Phosphoric Acid Plant (West)	A	FL	6/23/2006	0.0158	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SO2	1/8/2003	3.27	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER	1050059	MOSAIC FERTILIZER -	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SO2	12/18/2003	3.63	POUNDS PER TON OF	

LLC		NEW WALES PLANT											PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SO2	12/2/2004	3	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SO2	6/11/2003	3.6	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SO2	11/20/2003	3.37	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SO2	12/16/2004	3.6	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SO2	8/8/2006	3.85	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	SO2	9/19/2007	3.7	POUNDS PER TON OF PRODUCT	ses
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SAM	6/4/2003	0.039	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SAM	11/12/2003	0.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SAM	6/16/2005	0.02	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	9/4/2003	0.015	POUNDS PER TON OF FEED MATERIAL	1.06 lb/hr
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	5/1/2003	0.04	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	5/4/2004	0.014	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	2/17/2005	0.009	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	11/16/2005	0.0417	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	FL	2/23/2007	0.013	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SAM	4/18/2006	0.05	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SAM	8/29/2007	0.04	POUNDS PER TON OF PRODUCT	ses, 105 tph
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SAM	2/19/2008	0.01	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SAM	1/8/2003	0.05	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SAM	12/18/2003	0.03	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SAM	12/2/2004	0.05	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SAM	12/15/2005	0.07	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	SAM	8/29/2006	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant (East)	A	FL	6/7/2005	0.009	POUNDS PER TON OF FEED MATERIAL	LB/TON P2O5
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant (East)	A	FL	5/2/2006	0.017	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	8	Phosphoric Acid Plant (East)	A	FL	2/27/2007	0.015	POUNDS PER TON OF FEED MATERIAL	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	44	Sulfuric Acid Plant No. 5	A	NOX	12/16/2004	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	23	AFI Storage Silos (3) - "A" Side	A	PM	1/16/2004	0.01	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	FL	12/19/2003	0.35	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	FL	2/23/2005	0.13	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	FL	8/17/2006	0.08	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SAM	6/22/2005	0.05	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SAM	8/22/2006	0.04	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	42	Sulfuric Acid Plant No. 4	A	SAM	9/6/2007	0.01	POUNDS PER TON OF PRODUCT	ses
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	NOX	6/4/2003	0.0837	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	NOX	11/12/2003	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	NOX	6/16/2005	0.05	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	NOX	4/18/2006	0.06	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	NOX	8/29/2007	0.05	POUNDS PER TON OF PRODUCT	ses, 105 tph

MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	NOX	2/19/2008	0.07	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	FL	1/20/2006	0.79	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	11	MAP Plant	A	FL	7/12/2007	0.1	POUNDS/HOUR	ATC 50 tph
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	47	DAP Plant No 2 West Product Cooler	A	FL	3/18/2004	1.2	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	47	DAP Plant No 2 West Product Cooler	A	FL	4/1/2003	0.07	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	47	DAP Plant No 2 West Product Cooler	A	FL	3/18/2004	1.4	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	47	DAP Plant No 2 West Product Cooler	A	FL	2/17/2005	0.14	POUNDS/HOUR	TEST DATA FROM 2004 TEST
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	27	AFI Plant	A	PM	1/22/2004	29.88	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	27	AFI Plant	A	PM	3/23/2005	34.1	POUNDS/HOUR	RESULTS CORRECTED FOR ONE RUN AT % ISOKINETIC
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SO2	6/4/2003	3.34	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SO2	12/9/2004	2.18	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SO2	6/16/2005	3.3	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SO2	4/18/2006	3.3	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SO2	8/29/2007	3.3	POUNDS PER TON OF PRODUCT	ses, 105 tph
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	4	Sulfuric Acid Plant No. 3	A	SO2	2/19/2008	3.2	POUNDS PER TON OF PRODUCT	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	NOX	1/11/2007	5.53	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	NOX	8/31/2005	8.39	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	NOX	10/18/2005	8.05	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	NOX	11/14/2003	5.8	POUNDS/HOUR	11 tph raw feed
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	PM	11/17/2006	1.81	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	PM	2/24/2005	4.94	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	FL	11/17/2006	1.48	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	FL	2/24/2005	0.914	POUNDS/HOUR	0.414 cooler stack only. Actual above includes plant stack.
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	FL	3/15/2006	1.51	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	FL	3/21/2007	0.81	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	NOX	3/26/2003	0.88	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	NOX	1/28/2004	2.5	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	NOX	3/15/2006	1.66	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	NOX	3/21/2007	1.31	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	26	AFI Silica Unloading and Storage	A	PM	3/3/2004	0.27	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	37	Fertilizer Truck Loadout No. 2 w/ dust suppressant	A	PM	1/1/2005	0.0001	POUNDS/HOUR	NOT TESTED-BAGHOUSE NOT USED IN I OF DUST CONTROL OIL APPLICATION
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	FL	5/4/2004	0.188	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	NOX	6/22/2006	4.54	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	NOX	8/24/2007	7.45	POUNDS/HOUR	ses
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	74	Multifos C Kiln	A	SO2	1/11/2007	6.67	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	41	Fertilizer Truck Loadout No. 3 w/ dust suppressant	A	PM	1/1/2005	0.0001	POUNDS/HOUR	NOT TESTED-BAGHOUSE NOT USED IN I OF DUST CONTROL OIL APPLICATION
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	25	AFI Limestone Storage Silos (2)	A	PM	2/13/2004	2.5	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	NOX	12/2/2004	8.9	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	NOX	12/15/2005	5.08	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	3	Sulfuric Acid Plant No. 2	A	NOX	8/29/2006	6.3	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	4/1/2003	2.58	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	2/23/2007	1.66	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	2/14/2008	1.33	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	15	Animal Feed Ingredients (AFI) Shipping/Truck Loading	A	PM	3/19/2004	0.36	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	PM	1/29/2003	4.2	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	PM	3/30/2004	8.02	POUNDS/HOUR	gmap
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	PM	3/3/2005	2.41	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	9	DAP Plant No. 1	A	PM	3/29/2007	1.84	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	NOX	2/27/2003	6.25	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	2	Sulfuric Acid Plant No. 1	A	NOX	6/28/2005	6.45	POUNDS/HOUR	

MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	70	Limestone Storage Silo/Rock Grinding	A	PM	12/16/2003	0.05	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	47	DAP Plant No 2 West Product Cooler	A	PM	4/1/2003	1.46	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	9/4/2003	2.29	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	5/1/2003	3.77	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	4/6/2004	1.98	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	2/17/2005	2.04	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	PM	11/16/2005	3.88	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	5/4/2004	4.72	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	2/17/2005	2.86	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	11/16/2005	1.11	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	2/23/2007	1.85	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	2/14/2008	2.17	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	FL	3/26/2003	1.96	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	FL	1/28/2004	0.028	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	FL	1/28/2005	0.66	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	4/23/2004	10.8	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	6/30/2004	28.14	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	9/12/2005	13.38	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	9/27/2006	14.09	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	3/1/2006	15.63	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	9/7/2006	8.22	POUNDS/HOUR	SES, 7.3 tph (total A and B)
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	10/5/2007	6.81	POUNDS/HOUR	ses, 7 tph total production
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	PM	2/19/2004	0.04	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	PM	1/21/2003	0.005	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	36	Multifos A and B Kilns, Dryer and Blending Operation	A	PM	5/28/2003	20.27	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	PM	12/10/2004	0.026	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	PM	11/12/2004	0.012	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	PM	5/5/2006	0.0037	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	PM	12/21/2006	0.03	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	PM	3/26/2003	3.05	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	PM	1/28/2004	0.98	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	PM	3/15/2006	0.89	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	45	DAP Plant No 2 - East Train	A	PM	3/21/2007	1.28	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	52	AFI Limestone Feed Bin	A	PM	3/8/2004	0.2	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	FL	2/19/2004	0.002	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	FL	1/12/2003	0.004	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	FL	12/10/2004	0.002	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	FL	11/12/2004	0.0024	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	FL	5/5/2006	0.0021	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	48	30% Clarification Area (Area 10)	A	FL	12/21/2006	0.0014	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	46	DAP Plant No 2 - West Train	A	NOX	9/4/2003	2.31	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	FL	4/13/2006	0.466	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	PM	5/4/2004	1.57	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	56	DAP Plant No 2 East Product Cooler	A	PM	4/13/2006	0.25	POUNDS/HOUR	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	43	Fertilizer Rail Loadout No. 2 w/ dust suppressant	A	PM	1/1/2005	0.0001	POUNDS/HOUR	NOT TESTED-BAGHOUSE NOT USED IN I OF DUST CONTROL OIL APPLICATION
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	15	Animal Feed Ingredients (AFI) Shipping/Truck Loading	A	PM	3/19/2004	0	PERCENT OPACITY	5-year test for permit renewal
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	39	Phosphoric Acid Plant No. 3	A	FL	3/17/2003	5.59	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	39	Phosphoric Acid Plant No. 3	A	FL	5/29/2003	29.25	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	39	Phosphoric Acid Plant No. 3	A	FL	5/26/2005	17.4	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	39	Phosphoric Acid Plant No. 3	A	FL	5/27/2004	11.51	POUNDS/DAY	

MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	39	Phosphoric Acid Plant No. 3	A	FL	5/17/2006	8.1	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	39	Phosphoric Acid Plant No. 3	A	FL	3/5/2007	5.1	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	28	AFI Storage Silos (3) - "B" Side	A	PM	1/23/2004	0.01	PERCENT OPACITY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	28	AFI Storage Silos (3) - "B" Side	A	PM	1/6/2004	20	PERCENT OPACITY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	1/14/2003	2.3	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	2/12/2004	9.73	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	2/11/2003	1.55	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	12/17/2004	5.76	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	11/22/2004	22.08	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	5/3/2006	0.43	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	12/5/2004	5.76	POUNDS/DAY	DUPLICATE ENTRY
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	53	Phosphoric Acid Clarification and Storage Area	A	FL	12/12/2006	1.92	POUNDS/DAY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	25	AFI Limestone Storage Silos (2)	A	PM	2/13/2004	15	PERCENT OPACITY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	26	AFI Silica Unloading and Storage	A	PM	3/3/2004	0	PERCENT OPACITY	
MOSAIC FERTILIZER LLC	1050059	MOSAIC FERTILIZER - NEW WALES PLANT	SWD	POLK	A	Y	52	AFI Limestone Feed Bin	A	PM	3/8/2004	0	PERCENT OPACITY	
WINTER HAVEN HOSPITAL	1050072	WINTER HAVEN HOSPITAL	SWD	POLK	I	Y	2	INCINERATOR WITH HEAT RECOVERY BOILER	I	CO	12/8/2004	22	PARTS PER MILLION DRY GAS VOLUME	Test team: Air Testing & Consulting.
WINTER HAVEN HOSPITAL	1050072	WINTER HAVEN HOSPITAL	SWD	POLK	I	Y	2	INCINERATOR WITH HEAT RECOVERY BOILER	I	CO	11/13/2003	9.61	PARTS PER MILLION DRY GAS VOLUME	Test team: Air Testing & Consulting
WINTER HAVEN HOSPITAL	1050072	WINTER HAVEN HOSPITAL	SWD	POLK	I	Y	2	INCINERATOR WITH HEAT RECOVERY BOILER	I	PM	11/13/2003	0.0144	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	Test team: Air Testing & Consulting
WINTER HAVEN HOSPITAL	1050072	WINTER HAVEN HOSPITAL	SWD	POLK	I	Y	2	INCINERATOR WITH HEAT RECOVERY BOILER	I	PM	12/8/2004	0.014	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	Test team: Air Testing & Consulting.
WINTER HAVEN HOSPITAL	1050072	WINTER HAVEN HOSPITAL	SWD	POLK	I	Y	2	INCINERATOR WITH HEAT RECOVERY BOILER	I	H106	12/8/2004	7	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	Test team: Air Testing & Consulting.
WINTER HAVEN HOSPITAL	1050072	WINTER HAVEN HOSPITAL	SWD	POLK	I	Y	2	INCINERATOR WITH HEAT RECOVERY BOILER	I	H106	11/13/2003	0.623	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	Test team: Air Testing & Consulting
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	PM	9/22/2004	0.002	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	Test team: Air Testing & Consulting.
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	PM	8/18/2006	0.001	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	PM	8/8/2005	0.0023	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	PM	8/7/2007	0.002	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	H114	8/8/2005	0.0033	MILLIGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	PB	8/8/2005	0.0251	MILLIGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	H027	8/8/2005	0.0024	MILLIGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	CO	8/7/2007	15.13	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	CO	8/18/2006	6	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	CO	8/8/2005	6.06	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	ATC testing
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	CO	9/22/2004	9.95	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	Test team: Air Testing & Consulting.
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	H106	8/7/2007	27	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	
													PARTS PER	

LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	H106	8/18/2006	4	MILLION DRY GAS VOLUME @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	H106	8/8/2005	1.27	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	H106	9/22/2004	1.29	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	Test team: Air Testing & Consulting.
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	NOX	8/8/2005	93.4	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	SO2	8/8/2005	3.24	PARTS PER MILLION DRY GAS VOLUME @ 7% O2	
LAKELAND REGIONAL MEDICAL CENTER	1050095	LAKELAND REGIONAL MEDICAL CENTER	SWD	POLK	A	Y	2	BIOLOGICAL WASTE INCINERATOR	A	DIOX	8/8/2005	0.34	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
CITRUS WORLD, INC.	1050106	FLORIDA'S NATURAL GROWERS--BARTOW	SWD	POLK	I	Y	1	CITRUS PEEL DRYER, WITH WASTE HEAT EVAPORATOR	I	PM	11/18/2004	23.8	POUNDS/HOUR	
CITRUS WORLD, INC.	1050106	FLORIDA'S NATURAL GROWERS--BARTOW	SWD	POLK	I	Y	1	CITRUS PEEL DRYER, WITH WASTE HEAT EVAPORATOR	I	PM	9/30/2003	5	POUNDS/HOUR	
CITRUS WORLD, INC.	1050106	FLORIDA'S NATURAL GROWERS--BARTOW	SWD	POLK	I	Y	1	CITRUS PEEL DRYER, WITH WASTE HEAT EVAPORATOR	I	PM	1/22/2004	3.3	POUNDS/HOUR	
PEPPERIDGE FARM, INC	1050174	PEPPERIDGE FARM, INC	SWD	POLK	A	Y	16	Baking Line No. 5 - Cracker Oven No. 2	A	VOC	5/28/2004	99.3	PERCENT REDUCTION IN EMISSIONS	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	H106	4/17/2007	0.27	POUNDS/HOUR	clean air engineering
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	H106	5/2/2006	0.76	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	H106	4/30/2004	0.08	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	H106	4/30/2003	0.12	POUNDS/HOUR	Actual result reported as <0.12 lb/hr
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	H114	4/30/2004	0.00027	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	VOC	4/30/2004	1.1	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	VOC	4/30/2003	5.4	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	VOC	6/24/2005	7.17	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	VOC	4/17/2007	4.32	POUNDS/HOUR	clean air engineering
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	VOC	5/2/2006	3.49	POUNDS/HOUR	had put THC instead of VOC so I missed it the time round
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	NOX	6/28/2005	53	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	SO2	6/28/2005	0.61	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	CO	6/28/2005	8.3	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	H021	4/30/2004	0.00001	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	PB	4/30/2004	0.0002	POUNDS/HOUR	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	PM	4/30/2004	0.00052	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	PM	4/17/2007	0.00081	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	clean air engineering
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	PM	5/2/2006	0.0016	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	PM	4/30/2003	0.004	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
WHEELABRATOR RIDGE ENERGY INC.	1050216	RIDGE GENERATING STATION	SWD	POLK	A	Y	1	RGS BOILER STACK	A	PM	6/24/2005	0.0012	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	PM10= 1.42 lb/hr allowed 12.6 lb/hr / THC= 7. lb/hr allowed 22.1 lb/hr
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	NOX	3/18/2005	5.45	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	NOX	3/3/2004	5.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	CO	2/18/2008	1.92	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	CO	4/18/2006	0.73	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	CO	3/3/2004	16.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	CO	2/11/2003	4.46	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
													PARTS PER	

POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	CO	3/21/2005	5.49	MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	CO	2/22/2007	2.23	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
POLK POWER PARTNERS, L.P.	1050217	MULBERRY COGEN FACILITY	SWD	POLK	A	Y	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	A	NOX	2/11/2003	6.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	NOX	5/18/2007	11.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	NOX	9/30/2005	15.031	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RATA=7.53%
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	NOX	9/30/2004	10.133	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	NOX	7/11/2003	24.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	NOX	9/29/2004	22.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	NOX	5/17/2007	23.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	NH3	5/10/2006	2.36	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	NH3	5/16/2007	6.74	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	NOX	5/15/2007	2.41	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	TRC
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	VOC	5/17/2007	2.49	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	NOX	5/16/2007	2.52	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	CO	7/11/2003	2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	CO	9/29/2004	1.98	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	6	Simple Cycle Peaking CT	A	CO	5/17/2007	6.79	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	NH3	5/9/2006	1.31	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	NH3	5/15/2007	7.54	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	NOX	8/31/2006	12.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	NOX	5/9/2006	24.5	POUNDS/HOUR	CTw/PAG+DB
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	CO	5/15/2007	2.29	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	VOC	5/15/2007	0.66	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	CO	9/30/2005	0.2	PARTS PER MILLION DRY GAS VOLUME	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	CO	9/30/2004	0.8	PARTS PER MILLION DRY GAS VOLUME	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	VOC	5/16/2007	0.72	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	CO	7/10/2003	1	PARTS PER MILLION DRY GAS VOLUME	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	CO	5/16/2007	3.35	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	CO	5/10/2006	4.04	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	CT w/ PAG+DB
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	CO	8/31/2006	0.6	PARTS PER MILLION DRY GAS VOLUME	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	CO	5/18/2007	0.69	PARTS PER MILLION DRY GAS VOLUME	trc
APP, LP; APEC, LLC;		AUBURNDALE						170MW Combustion Turbine					PARTS PER MILLION DRY	

CCFC	1050221	ENERGY COMPLEX	SWD	POLK	A	Y	7	Configured for Combined Cycle	A	CO	5/9/2006	4.96	GAS VOLUME @ 15% O2 ISO	
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	1	Combined Combustion Turbine System(Phase II, Acid Rain Unit)	A	VOC	5/18/2007	1.32	POUNDS/HOUR	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	NOX	5/10/2006	26.9	POUNDS/HOUR	CT w/ PAG+DB
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	7	170MW Combustion Turbine Configured for Combined Cycle	A	PM	5/15/2007	11.4	POUNDS/HOUR	trc
APP, LP; APEC, LLC; CCFC	1050221	AUBURNDALE ENERGY COMPLEX	SWD	POLK	A	Y	8	170MW Combustion Turbine Configured for Combined Cycle	A	PM	5/16/2007	7.58	POUNDS/HOUR	trc
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	3	100 MMBtu/hr Package Steam Boiler	A	NOX	3/16/2004	0.061	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine and Heat Recovery System Generator	A	CO	1/8/2008	0.41	PARTS PER MILLION DRY GAS VOLUME	CO emission rate=1.4 lb/hr. Test team: C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine and Heat Recovery System Generator	A	CO	10/21/2003	0.53	PARTS PER MILLION DRY GAS VOLUME	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine and Heat Recovery System Generator	A	CO	10/24/2006	0.5	PARTS PER MILLION DRY GAS VOLUME	CO emission rate=19.3 lb/hr. Test team: C.E.M Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine and Heat Recovery System Generator	A	NOX	1/8/2008	11.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Test team: C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine and Heat Recovery System Generator	A	NOX	10/24/2006	12.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Test team: C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050223	TIGER BAY COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine and Heat Recovery System Generator	A	NOX	10/21/2003	7.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rain Unit)	A	NOX	2/26/2007	11.49	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rain Unit)	A	NOX	3/5/2004	14.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	NOX	3/8/2006	11.63	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	NOX	3/12/2004	13.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	NOX	2/27/2007	10.89	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rain Unit)	A	NOX	3/7/2006	11.43	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rain Unit)	A	PM	2/26/2007	4.81	POUNDS/HOUR	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rain Unit)	A	VOC	2/26/2007	4.54	PARTS PER MILLION DRY GAS VOLUME	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rain Unit)	A	CO	2/26/2007	27.12	PARTS PER MILLION DRY GAS VOLUME	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	SO2	11/27/2007	0.014	OTHER (SPECIFY IN COMMENT)	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	CO	11/27/2007	21.89	PARTS PER MILLION DRY GAS VOLUME	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	VOC	11/27/2007	0.023	PARTS PER MILLION DRY GAS VOLUME	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	3	Auxiliary Boiler	A	NOX	2/28/2007	0.097	POUNDS PER MILLION BTU HEAT INPUT	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	3	Auxiliary Boiler	A	NOX	3/18/2005	0.103	POUNDS PER MILLION BTU HEAT INPUT	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	3	Auxiliary Boiler	A	CO	2/28/2007	0.0005	POUNDS PER MILLION BTU HEAT INPUT	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	3	Auxiliary Boiler	A	VOC	2/28/2007	0.000032	POUNDS PER MILLION BTU HEAT INPUT	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	3	Auxiliary Boiler	A	NOX	12/2/2003	0.105	POUNDS PER MILLION BTU HEAT INPUT	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	3	Auxiliary Boiler	A	NOX	3/8/2006	0.1	POUNDS PER MILLION BTU HEAT INPUT	
ORANGE COGENERATION LIMITED PARTNERSHIP	1050231	ORANGE COGENERATION FACILITY	SWD	POLK	A	Y	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rain Unit)	A	PM	11/27/2007	5	POUNDS/HOUR	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	1/18/2007	193	POUNDS/HOUR	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	14	165 MW GE SIMPLE CYCLE COMBUSTION	C	CO	4/17/2007	0.1	POUNDS/HOUR	initial tetst

								TURBINE UNIT 5						
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SAM	3/23/2007	39	POUNDS/HOUR	SPECIAL PETCOKE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SAM	2/7/2006	31	POUNDS/HOUR	Petcoke/ coal blend
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SAM	5/20/2003	27	POUNDS/HOUR	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SAM	5/18/2005	22	POUNDS/HOUR	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SAM	11/8/2006	28	POUNDS/HOUR	SPECIAL TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SAM	1/18/2007	28	POUNDS/HOUR	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	14	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 5	C	SO2	4/17/2007	0.3	GRAINS SULFUR PER 100 STANDARD CUBIC FEET OF GAS	initial test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	3/1/2007	0.15	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	11/8/2006	0.12	POUNDS PER MILLION BTU HEAT INPUT	SPECIAL PETCOKE BASELINE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	8/3/2005	0.034	POUNDS PER MILLION BTU HEAT INPUT	Meth 10-CO, VE-9, NOX/SO2 data from CEM
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	2/21/2004	0.035	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	3	120 MMBtu/HR Auxiliary Boiler	A	SO2	3/11/2003	0.04	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	3	120 MMBtu/HR Auxiliary Boiler	A	SO2	8/22/2005	0.04	POUNDS PER MILLION BTU HEAT INPUT	from fuel analysis
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	3	120 MMBtu/HR Auxiliary Boiler	A	NOX	3/11/2003	0.06	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	VOC	5/1/2003	0.00056	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	VOC	3/1/2007	0.0004	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	VOC	3/1/2007	0.0004	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	5/1/2003	0.131	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	9/7/2003	0.035	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	2/5/2004	0.16	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	8/5/2005	0.15	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	12/1/2006	0.12	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	3/23/2007	0.11	POUNDS PER MILLION BTU HEAT INPUT	SPECIAL PETCOKE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	SO2	3/1/2007	0.15	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	13	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 4	A	SO2	3/5/2007	0.3	GRAINS SULFUR PER 100 STANDARD CUBIC FEET OF GAS	initial test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	PM	2/21/2004	0.007	POUNDS PER MILLION BTU HEAT INPUT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	13	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 4	A	SO2	3/5/2007	0.3	GRAINS SULFUR PER 100 STANDARD CUBIC FEET OF GAS	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	1/29/2008	2.18	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	6/12/2007	2.91	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	1/18/2007	3	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	11/8/2006	3	POUNDS PER TON OF PRODUCT	SPECIAL PETCOKE BASELINE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	9/14/2005	2	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	6/18/2003	0.5	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	2/12/2003	0.8	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	8/9/2005	0	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	8/8/2005	0	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	6/7/2004	0.5	PARTS PER MILLION DRY GAS VOLUME	

TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	2/13/2006	0	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	CO	7/10/2007	0.568	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SAM	2/12/2004	0.08	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SAM	12/1/2006	0.05	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SAM	11/8/2006	0.06	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SAM	3/23/2007	0.09	POUNDS PER TON OF PRODUCT	100% PETCOKE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SAM	1/18/2007	0.06	POUNDS PER TON OF PRODUCT	special petcoke test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	5/15/2003	3.5	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	2/12/2004	3	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	6/28/2006	2.88	POUNDS PER TON OF PRODUCT	teco
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	12/1/2006	3	POUNDS PER TON OF PRODUCT	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	6/25/2003	0.3	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	6/24/2003	0.3	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	8/10/2005	0	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	8/11/2005	0	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	6/9/2004	0.3	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	5/11/2006	0	PARTS PER MILLION DRY GAS VOLUME	CO below detectable limit approx 0.48ppm so, zero. Emissions ave. 1 lb/hr.
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	CO	7/11/2007	1	PARTS PER MILLION DRY GAS VOLUME	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	SO2	2/12/2003	0.76	OTHER (SPECIFY IN COMMENT)	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	SO2	8/9/2005	0.3	OTHER (SPECIFY IN COMMENT)	lb/hr
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	SO2	6/7/2004	0.2	OTHER (SPECIFY IN COMMENT)	LB/HR
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	SO2	2/13/2006	0.6	OTHER (SPECIFY IN COMMENT)	0.6 lb/hr allowed 9.2 lb/hr
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	SO2	7/10/2007	0.1	OTHER (SPECIFY IN COMMENT)	lb/hr from png analysis
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	SO2	6/25/2003	0.2	OTHER (SPECIFY IN COMMENT)	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	SO2	8/10/2005	0.4	OTHER (SPECIFY IN COMMENT)	calc. from fuel data
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	SO2	6/9/2004	0.2	OTHER (SPECIFY IN COMMENT)	LB/HR
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	SO2	5/11/2006	0.2	OTHER (SPECIFY IN COMMENT)	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	SO2	7/11/2007	0.1	OTHER (SPECIFY IN COMMENT)	lb/hr
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SAM	5/15/2003	0.15	POUNDS PER TON OF PRODUCT	8.5tph
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	4	Sulfuric Acid Plant	A	SO2	3/23/2007	3	POUNDS PER TON OF PRODUCT	SPECIAL PETCOKE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	13	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 4	A	CO	3/5/2007	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	initial test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	7/10/2007	7.026	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	3/1/2007	12	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	normal compliance test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	3/1/2007	12	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	1/8/2008	16.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	NOX	6/25/2003	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC		POLK POWER						165MW Simple Cycle					PARTS PER MILLION DRY	

COMPANY	1050233	STATION	SWD	POLK	A	Y	10	Combustion Turbine	A	NOX	6/24/2003	37	GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	NOX	8/10/2005	7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	NOX	8/11/2005	39	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	NOX	6/9/2004	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	NOX	5/11/2006	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	12/1/2006	2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	11/8/2006	3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	SPECIAL TEST BASELINE PETCOKE
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	1/18/2007	2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	special petcoke test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	3/23/2007	3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	SPECIAL PETCOKE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	3/1/2007	6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	3/1/2007	6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	1/8/2008	4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	5/1/2003	21.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	9/7/2003	32	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	14	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 5	C	NOX	4/17/2007	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	initial test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	13	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 4	A	NOX	3/5/2007	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	13	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 4	A	NOX	3/5/2007	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	initial tests
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	5/1/2003	3.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	9/7/2003	6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	2/5/2004	9.37	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	2/21/2004	1.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	8/5/2005	3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	8/23/2005	2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	CO	1/18/2006	3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	petcoke/ coal blend
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	2/5/2004	10.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	2/21/2004	30	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	8/5/2005	7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	8/23/2005	31	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	12/1/2006	13	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	11/8/2006	12	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	SPECIAL PETCOKE BASELINE TEST
													PARTS PER	

TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	1/18/2007	13	MILLION DRY GAS VOLUME @ 15% O2	special petcoke test
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	1	260 MW Combined cycle CT (Phase II Acid Rain Unit)	A	NOX	3/23/2007	14	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	SPECIAL PETCOKE TEST
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	NOX	7/11/2007	7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	SO2	6/18/2003	0.04	PERCENT SULFUR IN FUEL	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	6/18/2003	37	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	2/12/2003	6.95	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	8/9/2005	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	8/8/2005	34	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	6/7/2004	7.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	9	165MW Simple Cycle Combustion Turbine	A	NOX	2/13/2006	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	10	165MW Simple Cycle Combustion Turbine	A	SO2	6/24/2003	0.04	PERCENT SULFUR IN FUEL	
TAMPA ELECTRIC COMPANY	1050233	POLK POWER STATION	SWD	POLK	A	Y	13	165 MW GE SIMPLE CYCLE COMBUSTION TURBINE UNIT 4	A	CO	3/5/2007	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	CO	9/29/2005	2.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NH3	9/5/2007	3.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	CO	11/13/2003	0.76	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GAS FUEL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	CO	11/13/2003	0.63	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NH3	9/14/2006	2.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NH3	11/13/2003	2.23	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NOX	11/13/2003	2.98	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NOX	11/13/2003	8.88	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	CO	11/19/2007	0.96	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	CO	11/20/2007	0.95	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	17	POWER BLOCK 3, CT 3B	A	NH3	9/13/2006	2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	17	POWER BLOCK 3, CT 3B	A	NH3	9/6/2007	2.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NOX	11/13/2003	3.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NOX	11/13/2003	10.51	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	CO	11/13/2003	0.74	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GAS FUEL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	CO	11/13/2003	0.99	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	CO	9/29/2005	1.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	VOC	11/13/2003	0.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS	1050234	HINES ENERGY	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	VOC	11/13/2003	0.03	PARTS PER MILLION DRY	

ENERGY FLA		COMPLEX											GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	VOC	11/20/2007	0.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	VOC	11/19/2007	0.59	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	17	POWER BLOCK 3, CT 3B	A	NOX	10/22/2005	2.19	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NH3	11/13/2003	3.73	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GAS FUEL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NH3	11/13/2003	2.52	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NH3	11/2/2004	0.0001	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	NO NH3 USED ON OIL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NH3	11/4/2004	2.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NH3	9/14/2006	3.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	NH3	9/5/2007	3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	VOC	11/17/2007	0.32	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	VOC	11/20/2007	0.98	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	17	POWER BLOCK 3, CT 3B	A	NH3	10/22/2005	3.01	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	VOC	11/13/2003	0.47	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GAS FUEL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	VOC	11/13/2003	0.29	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	CO	11/20/2007	0.74	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	CO	11/17/2007	0.91	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	17	POWER BLOCK 3, CT 3B	A	VOC	10/22/2005	0.75	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	2	POWER BLOCK 1, CT 1B	A	NOX	12/7/2004	10.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	NOX	11/20/2007	8.77	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	NOX	11/17/2007	2.04	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	1	POWER BLOCK 1, CT 1A	A	NOX	12/7/2004	11	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	NOX	11/20/2007	7.61	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	NOX	11/19/2007	1.81	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NH3	11/13/2003	2.92	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GAS FUEL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	15	POWER BLOCK 2, CT 2B	A	NH3	11/4/2004	1.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	16	POWER BLOCK 3, CT 3A	A	NOX	10/22/2005	2.33	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	1	POWER BLOCK 1, CT 1A	A	CO	9/29/2005	0.3	PARTS PER MILLION DRY GAS VOLUME	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	1	POWER BLOCK 1, CT 1A	A	CO	9/4/2007	0.79	PARTS PER MILLION DRY GAS VOLUME	C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	2	POWER BLOCK 1, CT 1B	A	CO	12/7/2004	1.73	PARTS PER MILLION DRY GAS VOLUME	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	2	POWER BLOCK 1, CT 1B	A	CO	9/29/2005	0.5	PARTS PER MILLION DRY GAS VOLUME	
FLORIDA POWER													PARTS PER	

CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	2	POWER BLOCK 1, CT 1B	A	CO	9/4/2007	0.1	MILLION DRY GAS VOLUME	C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	16	POWER BLOCK 3, CT 3A	A	VOC	10/22/2005	0.76	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	16	POWER BLOCK 3, CT 3A	A	NH3	10/22/2005	3.92	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	16	POWER BLOCK 3, CT 3A	A	NH3	9/13/2006	1.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	16	POWER BLOCK 3, CT 3A	A	NH3	9/6/2007	0.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	C.E.M. Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	1	POWER BLOCK 1, CT 1A	A	CO	12/7/2004	0.26	PARTS PER MILLION DRY GAS VOLUME	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	16	POWER BLOCK 3, CT 3A	A	CO	10/22/2005	0.47	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	17	POWER BLOCK 3, CT 3B	A	CO	10/22/2005	0.53	PARTS PER MILLION DRY GAS VOLUME @ 15% O2 ISO	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	18	Power Block 4, CT 4A	A	NH3	11/17/2007	0.04	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas. (Ammonia slip for fuel oil: 0.58 pp
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	19	Power Block 4, CT 4B	A	NH3	11/19/2007	0.04	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Natural gas. (Ammonia slip for fuel oil: 0.92 pp
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	PM10	12/13/2003	0.0001	POUNDS/HOUR	TESTED FOR TOTAL PM ONLY
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1050234	HINES ENERGY COMPLEX	SWD	POLK	A	Y	14	POWER BLOCK 2, CT 2A	A	PM10	11/13/2003	0.0001	POUNDS/HOUR	TESTED FOR TOTAL PM
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	2	170MW combustion turbine configured as a combined cycle unit	I	NH3	6/8/2005	1.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	1	170MW Combustion Turbine Configured for Combined Cycle	I	NOX	6/11/2005	2.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	1	170MW Combustion Turbine Configured for Combined Cycle	I	NOX	5/5/2004	3.05	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	without duct burner
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	2	170MW combustion turbine configured as a combined cycle unit	I	NOX	5/7/2004	2.81	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	with duct burner
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	2	170MW combustion turbine configured as a combined cycle unit	I	NOX	6/8/2005	2.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	1	170MW Combustion Turbine Configured for Combined Cycle	I	CO	5/5/2004	0.26	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	without duct burner
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	1	170MW Combustion Turbine Configured for Combined Cycle	I	CO	6/11/2005	4.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	1	170MW Combustion Turbine Configured for Combined Cycle	I	NH3	5/5/2004	1.67	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	1	170MW Combustion Turbine Configured for Combined Cycle	I	NH3	6/11/2005	1.63	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	2	170MW combustion turbine configured as a combined cycle unit	I	CO	5/7/2004	0.31	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	using duct burner
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	2	170MW combustion turbine configured as a combined cycle unit	I	CO	6/8/2005	5.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
CALPINE CONSTRUCTION FINANCE COMPANY, LP	1050334	OSPREY ENERGY CENTER	SWD	POLK	I	Y	2	170MW combustion turbine configured as a combined cycle unit	I	NH3	5/5/2004	1.24	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	1	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NH3	12/9/2004	7.18	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	10	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NH3	1/28/2003	4.05	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	17	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NH3	12/4/2003	8.17	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	6	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	1/27/2003	8.3	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	7	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	1/28/2003	10.1	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	16	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/4/2003	8	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	17	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/4/2003	8.5	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	19	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/3/2003	8.2	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	1	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/9/2004	0.0001	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	1	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/9/2004	9.7	POUNDS/HOUR	

LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	4	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/8/2004	7.7	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	10	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	1/29/2003	7.2	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	20	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/3/2003	9.4	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	9	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	1/29/2003	10.2	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	8	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	1/28/2003	9.9	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	5	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/9/2004	6.7	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	18	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/4/2003	7.7	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	3	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/8/2004	9.4	POUNDS/HOUR	
LAKELAND ELECTRIC	1050352	WINSTON PEAKING STATION	SWD	POLK	A	Y	2	2.5 MW GM EMD 20/645/E4B diesel engine .	A	NOX	12/8/2004	7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	SO2	9/8/2005	0	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	SO2	2/26/2004	0.1	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	SO2	7/25/2006	1	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	SO2	1/14/2003	4.3	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	CO	7/25/2006	7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	CO	1/14/2003	1.8	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SO2	7/24/2006	14.6	POUNDS/HOUR	Methods 8 and 8A can be used to determine compliance as per proj 032-AC.
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SO2	1/17/2003	1.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	CO	1/17/2003	35.3	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	CO	1/17/2003	226	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	CO	3/2/2004	318	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	CO	7/24/2006	137.4	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	CO	9/6/2005	293	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	CO	6/10/2003	0	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	CO	2/24/2004	46.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	CO	8/19/2003	57.8	POUNDS/HOUR	100% soft wood. 1306 ADTBP = 90.7% produ rate.
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	CO	1/12/2005	53.4	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	CO	8/2/2006	22	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	CO	10/27/2006	20	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	PM	1/16/2003	9.15	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	PM	3/5/2004	5.3	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	PM	8/27/2004	10.21	POUNDS/HOUR	Average of North and South Vent.
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	PM	7/27/2006	7.6	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	PM	9/9/2005	6.9	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	PM	9/11/2007	8.1	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	TRS	1/14/2003	0.556	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	TRS	3/4/2004	0.6	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	TRS	7/25/2006	1.7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	TRS	9/8/2005	0.69	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	NOX	1/14/2003	32	POUNDS/HOUR	

GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	NOX	2/26/2004	33.7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	NOX	7/25/2006	16.8	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	NOX	9/8/2005	17.9	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	VOC	1/14/2003	0.609	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	VOC	2/26/2004	0.6	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	VOC	7/25/2006	0.1	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	VOC	9/8/2005	0.63	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	H115	2/24/2004	7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	H115	7/8/2005	0	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SO2	3/2/2004	4.3	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SO2	9/6/2005	0	POUNDS/HOUR	SO2 emissond test shall comply with Rule 62-297.4016(c), F.A.C. EPA Method 6(c)
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	CO	2/26/2004	1.4	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	CO	9/8/2005	1.96	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	VOC	1/17/2003	0.057	POUNDS PER TON BLACK LIQUOR SOLIDS	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	VOC	9/6/2005	0.05	POUNDS PER TON BLACK LIQUOR SOLIDS	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	VOC	9/12/2007	0.03	POUNDS PER TON BLACK LIQUOR SOLIDS	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	44	NO 7 PACKAGE BOILER REPLACING UNIT 034	A	NOX	5/23/2006	0.14	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	44	NO 7 PACKAGE BOILER REPLACING UNIT 034	A	NOX	5/16/2005	0.13	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	44	NO 7 PACKAGE BOILER REPLACING UNIT 034	A	NOX	5/23/2006	0.14	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	44	NO 7 PACKAGE BOILER REPLACING UNIT 034	A	NOX	10/17/2007	0.1	POUNDS PER BILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	1/6/2003	0.065	POUNDS PER MILLION BTU HEAT INPUT	steady state
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	1/27/2003	0.182	POUNDS PER MILLION BTU HEAT INPUT	soot blowing
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	1/8/2004	0.08	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	1/8/2004	0.11	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	4/28/2006	0.03	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	8/18/2006	0.05	POUNDS PER MILLION BTU HEAT INPUT	non-sootblowing
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	5/8/2006	0.1	POUNDS PER MILLION BTU HEAT INPUT	soot blowing burning DNCG's with #6 & 7 BS' operating
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	9/20/2005	0.09	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	9/20/2005	0.1	POUNDS PER MILLION BTU HEAT INPUT	soot blowing
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	6/9/2006	0.17	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	12/18/2006	0.034	POUNDS PER MILLION BTU HEAT INPUT	with DNCG's
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	12/20/2006	0.029	POUNDS PER MILLION BTU HEAT INPUT	without DNCG's
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	9/24/2007	0.02	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	15	No. 5 Power Boiler	A	PM	10/10/2007	0.05	POUNDS PER MILLION BTU HEAT INPUT	Soot Blowing
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	1/8/2003	0.033	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	1/8/2004	0.03	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	1/8/2004	0.09	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC		PALATKA PULP &											POUNDS PER	

CONSUMER OPERATIONS LLC	1070005	PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	8/8/2005	0.263	MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	8/18/2005	0.04	POUNDS PER MILLION BTU HEAT INPUT	WOOD & OIL
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	8/18/2005	0.05	POUNDS PER MILLION BTU HEAT INPUT	OIL ONLY
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	4/24/2006	0.04	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	9/25/2007	0.06	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	VOC	7/24/2006	0.01	POUNDS PER TON BLACK LIQUOR SOLIDS	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	1/8/2003	0.06	POUNDS PER MILLION BTU HEAT INPUT	bark and fuel mix
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	1/8/2003	0.033	POUNDS PER MILLION BTU HEAT INPUT	#6 fuel oil only.
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	16	No. 4 Combination Boiler	A	PM	1/8/2003	0.06	POUNDS PER MILLION BTU HEAT INPUT	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	VOC	3/2/2004	0.01	POUNDS PER TON BLACK LIQUOR SOLIDS	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	SO2	9/19/2007	4.8	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	SO2	8/20/2003	5.7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	H038	1/2/2003	0.106	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	H038	2/24/2004	1	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	TRS	7/27/2006	1.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	TRS	9/9/2005	1	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	TRS	9/11/2007	1.7	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	PM	1/14/2003	11.94	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	PM	2/26/2004	4.2	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	PM	8/26/2004	11.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	PM	7/25/2006	14.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	PM	9/8/2005	17.6	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	PM	9/14/2007	17	POUNDS/HOUR	Lime Mud Flow 378 gpm.
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SAM	1/17/2003	0.141	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SAM	3/2/2004	0.031	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SAM	7/24/2006	0.04	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SAM	9/6/2005	0	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SAM	9/12/2007	0.05	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	31	TALL OIL PLANT W/SCRUBBER	A	TRS	7/7/2007	0.019	POUNDS PER TON OF FEED MATERIAL	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	31	TALL OIL PLANT W/SCRUBBER	A	TRS	2/28/2008	0.022	POUNDS PER TON OF FEED MATERIAL	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	HAPS	8/2/2006	0.2	OTHER (SPECIFY IN COMMENT)	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	H038	8/19/2003	1	PARTS PER MILLION DRY GAS VOLUME	100% softwood. 1306 ADTBT production rate 90.7%. Permitted at 1440 ADTBT
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	H038	1/12/2005	0.5	PARTS PER MILLION DRY GAS VOLUME	concentration equals less than 0.5 ppm dv Cl
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	36	NEW ELEMENTAL CHLORINE-FREE BLEACH PLANT	A	H038	10/27/2006	0.2	PARTS PER MILLION DRY GAS VOLUME	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	TRS	1/16/2003	1.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	19	#4 SDTS (SMELT DISSOLVING TANKS); 2 TANKS, EACH W/ A SCRUBBE	A	TRS	3/5/2004	1.5	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER	1070005	PALATKA PULP &	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	SO2	2/24/2004	3.5	POUNDS/HOUR	

OPERATIONS LLC		PAPER MILL												
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	SO2	7/8/2005	2	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	SO2	8/3/2006	3	POUNDS/HOUR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	SO2	9/12/2007	4.4	TONS/YEAR	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	PM	1/17/2003	0.006	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	PM	8/26/2004	0.0133	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	TRS	7/24/2006	0.8	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	TRS	3/2/2004	1.4	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	TRS	1/17/2003	0.52	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	NOX	9/12/2007	60	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	NOX	9/6/2005	63.7	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	NOX	7/24/2006	49	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	NOX	3/2/2004	68	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	NOX	1/17/2003	74.26	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	CO	9/12/2007	359	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	SO2	9/14/2007	1.5	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	293 gpm
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	CO	9/14/2007	24	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	273 gpm
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	H115	9/19/2007	2	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	H115	8/3/2006	3.51	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	VOC	9/14/2007	7	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	273 gpm
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	NOX	9/14/2007	121	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	273 gpm
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	17	#4 Lime Kiln W/ high energy Zurn venturi scrubber;used-oil.	A	TRS	9/14/2007	0.5	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	273 gpm
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	HAPS	8/20/2003	2.609	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	37	THERMAL OXIDIZER	A	HAPS	2/24/2004	2	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	TRS	9/12/2007	0.7	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	TRS	9/6/2005	2.42	PARTS PER MILLION DRY GAS VOLUME @ 8% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	PM	9/6/2005	0.0062	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	PM	9/12/2007	0.004	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	PM	7/24/2006	0.013	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1070005	PALATKA PULP & PAPER MILL	NED	PUTNAM	A	Y	18	#4 RB (REC'Y BLR) W/ESP & LOW ODOR DESIGN;on-spec used-oil.	A	PM	3/2/2004	0.022	GRAINS PER DRY STANDARD CUBIC FOOT @ 7% O2	

FLORIDA POWER & LIGHT (PPN)	1070014	PUTNAM POWER PLANT	NED	PUTNAM	A	Y	10	Ductburners for CC HRSG22, Phase II Acid Rain Unit	A	NOX	11/29/2007	-0.3	POUNDS PER MILLION BTU HEAT INPUT	FPL
FLORIDA POWER & LIGHT (PPN)	1070014	PUTNAM POWER PLANT	NED	PUTNAM	A	Y	9	Ductburners for CC HRSG21, Phase II Acid Rain Unit	A	NOX	11/28/2007	-0.21	POUNDS PER MILLION BTU HEAT INPUT	FPL
FLORIDA POWER & LIGHT (PPN)	1070014	PUTNAM POWER PLANT	NED	PUTNAM	A	Y	7	Ductburners for CC HRSG11, Phase II Acid Rain Unit	A	NOX	11/27/2007	0.14	POUNDS PER MILLION BTU HEAT INPUT	FPL
FLORIDA POWER & LIGHT (PPN)	1070014	PUTNAM POWER PLANT	NED	PUTNAM	A	Y	8	Ductburners for CC HRSG12, Phase II Acid Rain Unit	A	NOX	11/27/2007	-0.14	POUNDS PER MILLION BTU HEAT INPUT	FPL
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	8/1/2006	0	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	VOC	5/24/2006	100	PERCENT REDUCTION IN EMISSIONS	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	VOC	5/21/2007	100	PERCENT REDUCTION IN EMISSIONS	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	VOC	2/4/2008	97.1	PERCENT REDUCTION IN EMISSIONS	distructiuon %
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	2	CONVEYING SYSTEM (SKINNER SAW & GLUE LINE EACH W/ A CYCLONE)	A	PM	5/6/2004	9.22	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	6/1/2006	0.55	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	6/1/2006	0.51	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	5/5/2004	0.98	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	5/7/2003	0.616	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	9/1/2004	2.8	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	6/2/2006	0.11	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	1	BOILER WOOD/BARK W/ ESP	A	PM	5/22/2007	0.46	POUNDS/HOUR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	PM	5/6/2003	3.69	TONS/YEAR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	VOC	5/6/2003	18.1	TONS/YEAR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	PM	5/18/2005	11.9	TONS/YEAR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	PM	5/5/2004	3.4	TONS/YEAR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	PM	5/24/2006	2.628	TONS/YEAR	
GEORGIA-PACIFIC WOOD PRODUCTS LLC	1070015	HAWTHORNE PLYWOOD PLANT	NED	PUTNAM	A	Y	5	#1,2,3 dryers with a RTO Unit to control VOC.	A	PM	2/4/2008	0.92418	TONS/YEAR	
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	7/19/2007	0.02	POUNDS PER MILLION BTU HEAT INPUT	Burning Coal. Burning Coal/Petcoke (70/30%) 0.020 lb/mmBtu. Tester: Catalyst Air Managen Inc. 2405 Byington-Solway Rd, Knoxville, TN (865) 531-0075
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	8/4/2006	0.022	POUNDS PER MILLION BTU HEAT INPUT	Burning Coal. Burning Coal/Petcoke (70/30%) 0.020 lb/mmBtu. Tester: Catalyst Air Managen Inc. 2405 Byington-Solway Rd, Knoxville, TN (865) 531-0075
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	7/19/2005	0.021	POUNDS PER MILLION BTU HEAT INPUT	Coal/Petcoke. Operating rate 657 MW. Catalys Management, Inc. Knoxville, TN (865) 531-00
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	6/2/2004	0.013	POUNDS PER MILLION BTU HEAT INPUT	Catalyst Air Management, Inc
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	4/14/2003	0.01848	POUNDS PER MILLION BTU HEAT INPUT	Testers were TECO
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	4/17/2003	0.03	POUNDS PER MILLION BTU HEAT INPUT	Testers were TECO
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	4/16/2003	0.01756	POUNDS PER MILLION BTU HEAT INPUT	Testers were TECO
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	6/1/2004	0.013	POUNDS PER MILLION BTU HEAT INPUT	Catalyst Air Management, Inc.
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	6/3/2004	0.014	POUNDS PER MILLION BTU HEAT INPUT	Catalyst Air Management, Inc
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	7/21/2005	0.016	POUNDS PER MILLION BTU HEAT INPUT	Coal/Petcoke. Operating rate 661 MW. Catalys Management, Inc. Knoxville, TN (865) 531-00
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	7/22/2005	0.014	POUNDS PER MILLION BTU HEAT INPUT	Coal. Operating rate 662 MW. Catalyst Air Management, Inc. Knoxville, TN (865) 531-00
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	8/1/2006	0.022	POUNDS PER MILLION BTU HEAT INPUT	Burning Coal. Burning Coal/Petcoke (70/30%) 0.019 lb/mmBtu. Tester: Catalyst Air Managen Inc. 2405 Byington-Solway Rd, Knoxville, TN (865) 531-0075
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	2	Steam Electric Generator No. 2	A	PM	7/20/2007	0.025	POUNDS PER MILLION BTU HEAT INPUT	Burning Coal. Burning Coal/Petcoke (70/30%) 0.024 lb/mmBtu. Tester: Catalyst Air Managen Inc. 2405 Byington-Solway Rd, Knoxville, TN (865) 531-0075
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	4/15/2003	0.02489	POUNDS PER MILLION BTU HEAT INPUT	Testers were TECO
SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	6/3/2004	0.02	POUNDS PER MILLION BTU HEAT INPUT	Catalyst Air Management, Inc

SEMINOLE ELECTRIC COOPERATIVE, INC.	1070025	SEMINOLE GENERATING STATION	NED	PUTNAM	A	Y	1	Steam Electric Generator No. 1	A	PM	7/20/2005	0.02	POUNDS PER MILLION BTU HEAT INPUT	Coal. Operating rate 659 MW. Catalyst Air Management, Inc. Knoxville, TN (865) 531-00
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	19	IMP MILL FLASH CALCINER SYSTEM B	A	PM	9/8/2004	0.0051	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	19	IMP MILL FLASH CALCINER SYSTEM B	A	PM	12/1/2005	0.0111	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	2	CAGE MILL DRYER SYSTEM #1	A	PM	9/8/2004	0.004	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	2	CAGE MILL DRYER SYSTEM #1	A	PM	9/27/2006	0.0106	GRAINS PER DRY STANDARD CUBIC FOOT	4.92 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	20	AMBIENT AIR FLASH COOLING SYSTEM B	A	PM	10/8/2003	0.003	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	20	AMBIENT AIR FLASH COOLING SYSTEM B	A	PM	12/1/2005	0.0048	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	5	AMBIENT AIR COOLING SYSTEM A	A	PM	9/25/2007	0.0178	GRAINS PER DRY STANDARD CUBIC FOOT	7.92 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	5	AMBIENT AIR COOLING SYSTEM A	A	PM	9/28/2006	0.0066	GRAINS PER DRY STANDARD CUBIC FOOT	2.78 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	5	AMBIENT AIR COOLING SYSTEM A	A	PM	9/27/2005	0.0154	GRAINS PER DRY STANDARD CUBIC FOOT	46 TPH
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	5	AMBIENT AIR COOLING SYSTEM A	A	PM	9/9/2004	0.0017	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	5	AMBIENT AIR COOLING SYSTEM A	A	PM	10/8/2003	0.0161	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	3	IMP MILL FEED SILO A (170-TON BIN)	A	PM	10/7/2003	0.0031	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	20	AMBIENT AIR FLASH COOLING SYSTEM B	A	PM	9/25/2007	0.0086	GRAINS PER DRY STANDARD CUBIC FOOT	3.63 lbs/hr PM
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	20	AMBIENT AIR FLASH COOLING SYSTEM B	A	PM	9/28/2006	0.0074	GRAINS PER DRY STANDARD CUBIC FOOT	2.76 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	20	AMBIENT AIR FLASH COOLING SYSTEM B	A	PM	9/30/2005	0.0079	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	23	CAGE MILL DRYER SYSTEM #2	A	PM	9/25/2007	0.0053	GRAINS PER DRY STANDARD CUBIC FOOT	2.32 lbs/hr PM
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	23	CAGE MILL DRYER SYSTEM #2	A	PM	9/27/2006	0.0129	GRAINS PER DRY STANDARD CUBIC FOOT	5.38 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	23	CAGE MILL DRYER SYSTEM #2	A	PM	9/29/2005	0.0035	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	23	CAGE MILL DRYER SYSTEM #2	A	PM	12/9/2005	0.0047	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	4	IMP MILL FLASH CALCINER SYSTEM A	A	PM	9/26/2007	0.0162	GRAINS PER DRY STANDARD CUBIC FOOT	2.34 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	4	IMP MILL FLASH CALCINER SYSTEM A	A	PM	9/28/2006	0.0091	GRAINS PER DRY STANDARD CUBIC FOOT	1.17 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	4	IMP MILL FLASH CALCINER SYSTEM A	A	PM	9/27/2005	0.0142	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	4	IMP MILL FLASH CALCINER SYSTEM A	A	PM	12/5/2005	0.0048	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	4	IMP MILL FLASH CALCINER SYSTEM A	A	PM	9/9/2004	0.0021	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	20	AMBIENT AIR FLASH COOLING SYSTEM B	A	PM	9/9/2004	0.0016	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	2	CAGE MILL DRYER SYSTEM #1	A	PM	9/25/2007	0.0087	GRAINS PER DRY STANDARD CUBIC FOOT	4.37 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	2	CAGE MILL DRYER SYSTEM #1	A	PM	9/28/2005	0.0169	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	2	CAGE MILL DRYER SYSTEM #1	A	PM	10/7/2003	0.0051	GRAINS PER DRY STANDARD CUBIC FOOT	
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	19	IMP MILL FLASH CALCINER SYSTEM B	A	PM	9/29/2005	0.0111	GRAINS PER DRY STANDARD CUBIC FOOT	

LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	19	IMP MILL FLASH CALCINER SYSTEM B	A	PM	9/28/2006	0.0107	GRAINS PER DRY STANDARD CUBIC FOOT	1.39 lbs/hr PM.
LAFARGE NORTH AMERICA, INC.	1070039	LAFARGE NORTH AMERICA, INC.	NED	PUTNAM	A	Y	19	IMP MILL FLASH CALCINER SYSTEM B	A	PM	9/26/2007	0.0106	GRAINS PER DRY STANDARD CUBIC FOOT	1.41 lbs/hr PM
VAW OF AMERICA, INC.	1090013	VAW OF AMERICA, INC.	NED	ST. JOHNS	I	Y	9	REMELT FURNACE NO. 2	I	PM	9/23/2003	0.55	POUNDS/HOUR	
VAW OF AMERICA, INC.	1090013	VAW OF AMERICA, INC.	NED	ST. JOHNS	I	Y	8	REMELT FURNACE NO. 1	I	PM	9/23/2003	0.98	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	9/27/2007	1.26	POUNDS/HOUR	30% painted scrap.
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	PM	5/5/2005	0.146	POUNDS/HOUR	Demonstrate compliance with NESHAP, 40 CF 63, Subpart RRR reqirements for secondary aluminum production. Tested by CleanAir Engineering, Palatine, IL (800)627-0033. www.cleanair.com
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	PM	10/20/2004	0.15	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	PM	5/3/2005	0.146	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	PM	5/5/2005	0.146	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	PM	8/8/2006	0.02	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	PM	8/8/2007	0.18	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	5/4/2005	0.427	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	5/5/2005	0.74	POUNDS/HOUR	Demonstrate compliance with NESHAP, 40 CF 63, Subpart RRR reqirements for secondary aluminum production. Tested by CleanAir Engineering, Palatine, IL
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	10/19/2004	0.35	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	5/4/2005	0.313	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	5/4/2005	0.313	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	5/4/2005	0.427	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	8/8/2006	0.36	POUNDS/HOUR	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	PM	9/27/2007	1.26	POUNDS/HOUR	30% painted scrap.
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	H106	5/4/2005	0.0688	POUNDS PER TON OF FEED MATERIAL	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	4	Remelt Furnace No. 2	A	H106	5/4/2005	0.00355	POUNDS PER TON OF FEED MATERIAL	
HALNA, INC.	1090447	HYDRO ALUMINUM OF NORTH AMERICA - ST. AU	NED	ST. JOHNS	A	Y	3	Remelt Furnace No. 1 (North Furnace)	A	H106	5/3/2005	0.000089	POUNDS PER TON OF FEED MATERIAL	
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	VOC	8/22/2007	0.059	POUNDS/HOUR	RN: NG drng the tst. VOC=0.0002#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	VOC	8/21/2007	0.106	POUNDS/HOUR	RN: NG drng the tst; VOC=0.0002#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	NOX	8/23/2007	50.22	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RN: NOc at ISO cond=59.9 ppm ; NOx=58.63
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	NOX	9/28/2005	55.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RN: NOx@ISO=81 PPM; NOx =0.205#/MMBTU=63.44#/hr; HI=309MMBTU during the tst.
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	NOX	8/24/2006	56.06	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RN: NOx at ISO=67.2 NOx= 0.205#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	NOX	8/5/2004	49.63	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RN: NOx=54.22#/hr =.183#/mmbtu (NG durin test).
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	NOX	8/6/2003	53.42	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RN-NOx=55.60 # / hr; =0.184#/MMBTU on N
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	CO	8/21/2007	0.21	POUNDS/HOUR	RN: NG drng the tst; CO=0.0004 #/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	CO	8/9/2003	1.378	POUNDS/HOUR	RN- NG drng the test;CO=0.0023 #/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	CO	9/28/2005	0.641	POUNDS/HOUR	RN: NG drng the tst. CO=0.0010#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	CO	8/23/2006	1.149	POUNDS/HOUR	RN: CO=0.0018#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	NOX	9/29/2005	99.8	POUNDS/HOUR	RN: NG drng the tst. NOx= 0.227#/MMBTU;HI=440MMBTU/HR
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	NOX	8/4/2004	100.8	POUNDS/HOUR	RN: NOx=0.222#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	CO	8/23/2007	0.8	POUNDS/HOUR	RN: CO=0.93 ppm, CO=0.0026#/MMBTU

FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	CO	8/24/2006	0.83	POUNDS/HOUR	RN: CO= 0.003#/mmbtu
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	CO	8/7/2003	0.094	POUNDS/HOUR	RN-CO=0.0002 #/MMBTU NG drng the tst).
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	CO	8/4/2004	0.209	POUNDS/HOUR	RN; CO=0.0005#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	CO	8/22/2006	3.65	POUNDS/HOUR	RN: CO= 0.0085#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	CO	9/29/2005	4.6	POUNDS/HOUR	RN: NG dng the tst; CO=0.011#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	CO	8/22/2007	0.2	POUNDS/HOUR	RN: NG drng the tst; CO=0.0021#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	CO	8/6/2003	1.03	POUNDS/HOUR	RN- CO=0.03 # / MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	CO	8/5/2004	0.7	POUNDS/HOUR	RN: CO=0.002#/mmbtu
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	3	23.4 MW CCGT with 8.2 MW HRSG Unit # 9	A	CO	9/27/2005	0.93	POUNDS/HOUR	RN: CO=0.003#/MMBTU; NG drng the tsts ; HI=309MMBTU/HR
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	NOX	8/7/2003	104.16	POUNDS/HOUR	RN on NG NOX=0.260#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	NOX	8/22/2006	99.5	POUNDS/HOUR	RN: NOx= 0.231#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	7	37.5 MW Boiler Unit #7 (Phase II Acid Rain Unit)	A	NOX	8/22/2007	92.9	POUNDS/HOUR	RN: NG drng the tst. NOx=0.252#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	CO	8/3/2004	1.269	POUNDS/HOUR	RN: CO=0.0020#/mmbtu; note gas flow in 100
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	NOX	8/21/2007	0.18	POUNDS PER MILLION BTU HEAT INPUT	RN: NG drng the tst. NOx=101.9#/hr; Note tha NOx tst were also conducted on additional 3 lo 12.1 MW (HV=175.5)- NOX= 0.0643#/MMB 23.1 MW (HV=305.8)- NOX= 0.094#/MMBT 34.1 MW (HV=425.5 MMBTU/hr) -NOX= 0.124#/MMBTU
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	NOX	9/28/2005	0.178	POUNDS PER MILLION BTU HEAT INPUT	RN: NG drng the tst. NOx=114.29#/hr; HI=641 MMBTU/HR
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	NOX	8/3/2004	0.19	POUNDS PER MILLION BTU HEAT INPUT	RN:NOx=120.73#/hr; note gas flow in 100scfm
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	NOX	8/9/2003	0.149	POUNDS PER MILLION BTU HEAT INPUT	RN: 2003 tst on NG; NOx=88.20 #/hr
FT PIERCE UTILITIES AUTHORITY	1110003	FT PIERCE UTIL/H D KING PWR PLNT	SED	ST. LUCIE	A	Y	8	56.1 MW Boiler Unit #8 (Phase II Acid Rain Unit)	A	NOX	8/23/2006	0.158	POUNDS PER MILLION BTU HEAT INPUT	RN: NOX= 101.10#/hr (HI=638MMBTU/hr vs
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	8	New Process Steam Boiler	A	NOX	4/26/2004	0.025	POUNDS PER MILLION BTU HEAT INPUT	RN: 1 st test (NOX and CO) in 2004.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	8	New Process Steam Boiler	A	NOX	3/19/2003	0.031	POUNDS PER MILLION BTU HEAT INPUT	RN- initial stck tst on NG (not conctd on oil ye cndtd by Catalyst Air Management, Inc.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	1	PEEL DRYER #1 & WASTE HEAT EVAPORATOR #1 W/SEPRTR.& WET CYCL	A	PM	3/26/2007	4.32	POUNDS/HOUR	RN: PM=0.029 grain/dscf; not within +-10% o 45T/hr (full capacity) -85.11%
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	4	PEEL DRYER #2 AND WASTE HEAT EVAPORATOR #2	A	PM	3/27/2007	3.39	POUNDS/HOUR	RN: PM=0.020 grain/dscf; not within +- 10% o 45t/hr (74%); CATALYST AIR ANAGEMENT ,INC conducted the test.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	4	PEEL DRYER #2 AND WASTE HEAT EVAPORATOR #2	A	PM	4/28/2004	4.53	POUNDS/HOUR	RN: Catalyst(Air Management ,Inc.); PM=0.029Gr/DSCF
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	4	PEEL DRYER #2 AND WASTE HEAT EVAPORATOR #2	A	PM	4/23/2003	6.54	POUNDS/HOUR	RN- 2003 PM test
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	4	PEEL DRYER #2 AND WASTE HEAT EVAPORATOR #2	A	PM	4/19/2005	2.37	POUNDS/HOUR	RN: PM=0.016gr/DSCF; Tested on the load eq 27.22T/Hrthat is =60.48% of the capacity <=-1 the capacity.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	4	PEEL DRYER #2 AND WASTE HEAT EVAPORATOR #2	A	PM	3/28/2006	5.21	POUNDS/HOUR	RN: PM=0.037 gr/dscf; Catalyst- stack test cre NG drng the test.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	1	PEEL DRYER #1 & WASTE HEAT EVAPORATOR #1 W/SEPRTR.& WET CYCL	A	PM	4/22/2003	5.02	POUNDS/HOUR	RN- 2003 PM test.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	1	PEEL DRYER #1 & WASTE HEAT EVAPORATOR #1 W/SEPRTR.& WET CYCL	A	PM	3/28/2006	6.1	POUNDS/HOUR	RN: PM=0.039gr/dscf; Test crew Catalyst Air Management, Inc. NG during the test.
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	1	PEEL DRYER #1 & WASTE HEAT EVAPORATOR #1 W/SEPRTR.& WET CYCL	A	PM	4/28/2004	3.41	POUNDS/HOUR	RN
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	1	PEEL DRYER #1 & WASTE HEAT EVAPORATOR #1 W/SEPRTR.& WET CYCL	A	PM	4/18/2005	2.91	POUNDS/HOUR	RN: prfrmd by Catalyst Air Management ,Inc.; PM=0.024 Grain/DSCF Input=32.8T/Hr=72.88 capacity .
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	8	New Process Steam Boiler	A	CO	4/26/2004	7.3	PARTS PER MILLION DRY GAS VOLUME	RN: note the unis shld be ppm@3%O2
TROPICANA MANFACTURING COMPANY, INC	1110004	TROPICANA, FORT PIERCE	SED	ST. LUCIE	A	Y	8	New Process Steam Boiler	A	CO	3/19/2003	1.2	PARTS PER MILLION DRY GAS VOLUME	RN- note CO=1.2 ppm @3% O2 (no such unit ARMS)! tst on NG not cntd yet on oil (Stan)
CARGILL JUICE NORTH AMERICA	1110018	FT. PIERCE	SED	ST. LUCIE	I	Y	7	60,000 LB/HR PEEL DRYER W/ TWO (2) WASTE HEAT EVAPORATORS	I	PM	1/8/2004	7.2	POUNDS/HOUR	RN: 2004 PM tst
CARGILL JUICE NORTH AMERICA	1110018	FT. PIERCE	SED	ST. LUCIE	I	Y	7	60,000 LB/HR PEEL DRYER W/ TWO (2) WASTE HEAT EVAPORATORS	I	PM	1/9/2003	8	POUNDS/HOUR	RN- see comnts on the activity scrn. PM=0.049 grains/dscf
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	CO	7/17/2007	7.8	POUNDS/HOUR	RN: (flow=28100scfH)
FLORIDA GAS		FGTC COMPRESSOR						4000 BHP I.C.Reciprocating						

TRANSMISSION COMPANY	1110060	STATION 20	SED	ST. LUCIE	A	Y	5	Engine & Assoc.Equip. #2005	A	CO	7/13/2006	7.2	POUNDS/HOUR	RN: Load:4101HP; 28550scfh (fuel flow)
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	CO	7/13/2005	7.84	POUNDS/HOUR	RN: NG drng the tst. Hinput =30.09 MMBTU/l 33.36, and 3935 HP vs 4000.
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	CO	7/17/2007	9.3	POUNDS/HOUR	RN (flow =18682scfH) HP=(2471;2463; and 2 for three runs).
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	CO	7/13/2005	11.7	POUNDS/HOUR	RN: NG drng tsts. Stack tsts load =2386 HP vs HP and 18.87 MMBTU/hr vs 21.19.
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	CO	8/19/2003	9.11	POUNDS/HOUR	RN- NG during the test;CO=306.4 ppm
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	NOX	7/13/2006	5.16	POUNDS/HOUR	RN: NOx=0.99g/hp-hr; cndtd by DeNOvo-nv, Load: 2373HP; 17693scfh(fuel flow)
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	NOX	8/20/2003	7.49	POUNDS/HOUR	RN- NG drng the tsts;NOx=62.16 ppm
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	NOX	8/19/2004	11.5	POUNDS/HOUR	RN: NOx=1.314g/bhp-hr; load=3973 bhp
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	NOX	7/13/2005	12.1	POUNDS/HOUR	RN: NG drng tst, NOX=1.40 (g/bhp-hr) vs 2.0 load drng tsts =3935HPvs 4000 and 30.09 MMBTU/hr vs 33.36MMBTU/hr
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	NOX	7/13/2006	8.06	POUNDS/HOUR	RN: Nox=0.89g/hp-hr;Load:4101HP;Fuel flow:28550scfh
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	NOX	7/17/2007	9.1	POUNDS/HOUR	RN; NOx=1g/hp-hr ; Flow =28100 scfH
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	NOX	8/19/2003	5.71	POUNDS/HOUR	RN- NOx=108.3 ppm
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	NOX	9/22/2004	8.62	POUNDS/HOUR	RN: NOx=1.66 g/bhp-hr; Q=17851 SCF/h
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	NOX	7/13/2005	7.44	POUNDS/HOUR	RN: NG drng the tst. NOx=1.42 g/bhp-hrloadn drng tst=18.87MMBTU/hr and within =-10% o
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	NOX	7/17/2007	7.3	POUNDS/HOUR	RN: DENOVO cndtd stack tsts; NOx=1.4g/hp-
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	CO	9/22/2004	9.8	POUNDS/HOUR	RN: NG drng the test, Q=17851 SCFH; CO=35 ppm dry
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	4	2400 BHP NAT GAS FIRED RECIP IC ENGINE #2004	A	CO	7/13/2006	8.37	POUNDS/HOUR	RN: Load:2373HP;fuel flow 17693scfh (294sc
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	CO	8/19/2004	8.07	POUNDS/HOUR	RN
FLORIDA GAS TRANSMISSION COMPANY	1110060	FGTC COMPRESSOR STATION 20	SED	ST. LUCIE	A	Y	5	4000 BHP I.C.Reciprocating Engine & Assoc.Equip. #2005	A	CO	8/20/2003	9.72	POUNDS/HOUR	RN- NG drng the tsts;CO=132.9 ppm
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	16	PRILL TOWER-10 EXHAUST FANS & SCRUBBER EXHAUST VENT	I	PM	3/14/2005	7.46	POUNDS/HOUR	Emissions are the total from the prill tower (5.6 and prill scrubber (1.77). Based on process wei table (62-296.320) max emissons allowed were pph.
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	16	PRILL TOWER-10 EXHAUST FANS & SCRUBBER EXHAUST VENT	I	PM	1/30/2003	6.42	POUNDS/HOUR	
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	16	PRILL TOWER-10 EXHAUST FANS & SCRUBBER EXHAUST VENT	I	PM	3/26/2004	7.46	POUNDS/HOUR	Prill Tower (5.21 pph) + Heil Scrubber (2.25 p 7.46 pph
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	16	PRILL TOWER-10 EXHAUST FANS & SCRUBBER EXHAUST VENT	I	PM	2/11/2005	8.65	POUNDS/HOUR	Combined emissions from scubber and tower.
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	14	AMMONIUM NITRATE PLANT 83%	I	PM	12/1/2004	0.03	POUNDS PER TON OF PRODUCT	
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	22	NITRIC ACID PLANT NO.1 CATALYTIC COMBUSTOR	I	NOX	2/13/2004	0.07	POUNDS PER TON OF PRODUCT	TESTED IN HOUSE; Plant 1 limited to 309.21 production until retested.
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	23	NITRIC ACID PLANT NO.2 CATALYTIC COMBUSTOR	I	NOX	1/25/2005	1.05	POUNDS PER TON OF PRODUCT	TPY in operating rate section is misleading. Th number given is Plants 1 & 2 combined.
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	23	NITRIC ACID PLANT NO.2 CATALYTIC COMBUSTOR	I	NOX	2/17/2004	1.09	POUNDS PER TON OF PRODUCT	TESTED IN HOUSE
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	23	NITRIC ACID PLANT NO.2 CATALYTIC COMBUSTOR	I	NOX	2/28/2003	0.9	POUNDS PER TON OF PRODUCT	
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	23	NITRIC ACID PLANT NO.2 CATALYTIC COMBUSTOR	I	NOX	2/17/2004	1.09	POUNDS PER TON OF PRODUCT	In house testing
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	14	AMMONIUM NITRATE PLANT 83%	I	NH3	12/1/2004	1	POUNDS PER TON OF PRODUCT	
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	22	NITRIC ACID PLANT NO.1 CATALYTIC COMBUSTOR	I	NOX	2/25/2003	0.33	POUNDS PER TON OF PRODUCT	Test conducted in-house. Max operating rate reduced to 418 until retested.
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	22	NITRIC ACID PLANT NO.1 CATALYTIC COMBUSTOR	I	NOX	11/3/2004	0.175	POUNDS PER TON OF PRODUCT	
TAMINCO METHYLAMINES INC	1130004	TAMINCO PACE PLANT	NWD	SANTA ROSA	A	Y	22	NITRIC ACID PLANT NO.1 CATALYTIC COMBUSTOR	I	NOX	2/13/2004	0.07	POUNDS PER TON OF PRODUCT	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	38	1000 HP Ingersol Rand Compressor engine with catalytic cnvtr	A	CO	9/13/2007	1.4	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	NOX	9/18/2007	2.02	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	NOX	9/11/2007	3.83	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	NOX	9/18/2007	0.78	POUNDS/HOUR	
QUANTUM		ST REGIS TREATING						Three Sulfur Recovery Plants					OTHER	

RESOURCES MGMNT LLC	1130005	FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	(2, 3, & 4)	A	SO2	11/4/2003	0.051	(SPECIFY IN COMMENT)	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	11/17/2004	0.08	OTHER (SPECIFY IN COMMENT)	tested at 2.2 MM scf/d; sulfur recovery efficien actual was 96%
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	5/3/2006	0.067	OTHER (SPECIFY IN COMMENT)	1.8 MMscf/d acid gas flow rate; 96.6% sulfur recovery
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	6/7/2006	0.065	OTHER (SPECIFY IN COMMENT)	1.8 MMscf/d acid gas flow rate; 96.68% sulfur recovery
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	2/3/2005	0.091	OTHER (SPECIFY IN COMMENT)	tested at 2.3 MMscf/day; sulfur recovery was 9
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	2/17/2005	0.0674	OTHER (SPECIFY IN COMMENT)	2.3 MMscf/day; sulfur recovery 96.6%
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	5/11/2005	0.071	OTHER (SPECIFY IN COMMENT)	2.2 MMscf/day acid gas flow; sulfur recovery 9
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	6/16/2005	0.0622	OTHER (SPECIFY IN COMMENT)	2.0 MMscf/day acid gas flow; sulfur recovery 9
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	5/30/2007	0.053	OTHER (SPECIFY IN COMMENT)	sulfur recover - 97.3%
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	34	Three Sulfur Recovery Plants (2, 3, & 4)	A	SO2	6/22/2007	0.0649	OTHER (SPECIFY IN COMMENT)	96.73% sulfur recovery
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	37	JCSWD 3600 HP NG fired Solar Centaur turbine	A	NOX	11/5/2003	81	PARTS PER MILLION DRY GAS VOLUME	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	NOX	9/17/2007	1.09	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	NOX	9/18/2007	3.34	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	NOX	9/18/2007	4.01	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	38	1000 HP Ingersol Rand Compressor engine with catalytic cnvtr	A	NOX	9/13/2007	2.8	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	38	1000 HP Ingersol Rand Compressor engine with catalytic cnvtr	A	NOX	11/5/2003	3.35	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	38	1000 HP Ingersol Rand Compressor engine with catalytic cnvtr	A	VOC	9/13/2007	0.2	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	CO	9/18/2007	1.23	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	CO	9/18/2007	2.74	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	CO	9/18/2007	1.29	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	CO	9/11/2007	3.56	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	CO	9/17/2007	1.41	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	VOC	9/11/2007	0.21	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	50	14,300-Hp South Water Flood Gas Turbine	A	NOX	3/20/2007	15.2	POUNDS/HOUR	Test performed in September 2007 also.
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	50	14,300-Hp South Water Flood Gas Turbine	A	CO	3/20/2007	47.1	POUNDS/HOUR	Re-test to be performed due to unit not operatin capacity
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	VOC	9/18/2007	0.02	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	VOC	9/18/2007	0.02	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	VOC	9/17/2007	0.07	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	VOC	9/18/2007	0.07	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	VOC	9/18/2007	0.002	POUNDS/HOUR	
QUANTUM RESOURCES MGMNT LLC	1130005	ST REGIS TREATING FAC AND JAY GAS PLANT	NWD	SANTA ROSA	A	Y	44	Six 1,000 HP NG Ingersol Rand Compressor Engines w cat. conv	A	CO	9/18/2007	1.8	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	6/12/2007	0.061	POUNDS/HOUR	Heat input limited to 34.96MMBtu/hour (110% testing). Sulfur determined from Fuel
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	8/25/2005	0.00504	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	7/13/2004	0.00795	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	12/21/2005	0.0026	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	10/23/2006	0.012	POUNDS/HOUR	DeNovo=nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	5/28/2003	0.011	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	6/12/2007	16.01	POUNDS/HOUR	Heat input limited to 34.96MMBtu/hour (110% testing)
FLORIDA GAS TRANSMISSION	1130037	COMPRESSOR	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC	A	NOX	5/28/2003	15.9	POUNDS/HOUR	

COMPANY		STATION #12						Compressor Engine						
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	NOX	5/28/2003	17.6	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	NOX	7/13/2004	12.9	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	NOX	8/25/2005	11.6	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	NOX	12/21/2005	12.7	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	NOX	10/23/2006	16.4	POUNDS/HOUR	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	NOX	6/12/2007	12.46	POUNDS/HOUR	Heat input limited to 34.96MMBtu/hour (110% testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	5/28/2003	17.2	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	5/28/2003	17.2	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	7/13/2004	18.2	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	8/25/2005	17.3	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	12/21/2005	20	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	CO	10/23/2006	12.8	POUNDS/HOUR	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	6	FGT Unit 1206 - Reciprocating IC Compressor Engine	A	SO2	5/28/2003	0.011	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	CO	6/12/2007	0.16	GRAMS PER HORSEPOWER-HOUR	Heat input limited to 15.98MMBtu/hour (110% testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	CO	12/21/2005	0.069	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	CO	7/13/2004	0.0471	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	NOX	9/10/2003	3.4	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	NOX	7/13/2004	4.81	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	NOX	8/25/2005	2.44	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	NOX	12/21/2005	3.1	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	NOX	10/23/2006	2.6	GRAMS PER HORSEPOWER-HOUR	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	NOX	6/12/2007	2.58	GRAMS PER HORSEPOWER-HOUR	Heat input limited to 15.77MMBtu/hour (110% testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	NOX	9/10/2003	3.89	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	NOX	7/13/2004	2.82	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	NOX	8/24/2005	4.62	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	NOX	12/21/2005	4.49	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	CO	9/10/2003	0.082	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	CO	7/13/2004	0.0569	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	CO	8/25/2005	0.0367	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	CO	12/21/2005	0.354	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	CO	10/23/2006	0.04	GRAMS PER HORSEPOWER-HOUR	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	CO	6/12/2007	0.06	GRAMS PER HORSEPOWER-HOUR	Heat input limited to 15.77MMBtu/hour (110% testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	NOX	11/8/2006	1.14	GRAMS PER HORSEPOWER-HOUR	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	NOX	6/12/2007	1.67	GRAMS PER HORSEPOWER-HOUR	Heat input limited to 15.98MMBtu/hour (110% testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	CO	9/10/2003	0.24	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	CO	8/24/2005	0.0527	GRAMS PER HORSEPOWER-HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	CO	11/8/2006	0.23	GRAMS PER HORSEPOWER-HOUR	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	12/21/2007	1.76	PARTS PER MILLION DRY GAS VOLUME	Tested by DeNovo; restricted to 129 MMBtu/hr (110% of testing)

COMPANY													@ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	12/20/2005	1.74	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	8/23/2005	3.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	10/24/2006	0.22	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	6/11/2007	1.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input limited to 123MMBtu/hour (110% o testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	9/10/2003	1.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	6/12/2003	1.88	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Mid High Load; 112037-008-AC changed testi requirement; only required to test at max capac with a limit of 21 ppm in 2004.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	6/12/2003	1.87	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	High Load; 112037-008-AC changed testing requirement; only required to test at max capac with a limit of 21 ppm in 2004.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	6/12/2003	1.87	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	6/12/2003	2.24	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Construction permit 1130037-007and 008-AC changed requirement to test at max load only.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	7/12/2004	1.07	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	8/24/2005	1.45	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	12/21/2005	0.06	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	10/24/2006	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	CO	6/11/2007	1.07	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input limited to 132MMBtu/hour (110% o testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	3/11/2004	12	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Mid-Low Load
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	3/11/2004	16.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Mid-High Load
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	3/11/2004	20.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Full-load. Heat input is 111.45 MMBtu @ 68.2 degrees F. Adjusts to 113.9 MMBtu at the ref T of 59 degrees F.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	9/10/2003	24.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	8/23/2005	15.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Test conditions are adjusted to 107 MMBtu/hr a reference temperature of 59 degrees F. This is 8 of capacity.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	12/20/2005	22.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input curve used to determine % capacity test with an air inlet temp of 44 degrees F.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	10/24/2006	19.68	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	6/11/2007	21.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input limited to 123MMBtu/hour (110% o testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	12/21/2007	15.54	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Tested by DeNovo; restricted to 129 MMBtu/hr (110% of testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	NOX	3/11/2004	22.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Low Load
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	NOX	6/12/2003	2.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	NOX	7/12/2004	20.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Test conditions: 114.77 MMBtu/hr at 80.3 degr F. Adjusts to 122.7 MMBtu/hr at the reference temperature of 59 degrees F.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	NOX	8/24/2005	18.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	NOX	12/21/2005	19.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input curve used to determine % capacity test with an air inlet temp of 48 degrees F.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	NOX	10/24/2006	18.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION	1130037	COMPRESSOR	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New	A	NOX	6/11/2007	22.87	PARTS PER MILLION DRY	Heat input limited to 132MMBtu/hour (110% o

COMPANY		STATION #12						15,700 bhp gas turbine					GAS VOLUME @ 15% O2	testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	CO	3/11/2004	3.48	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	3/11/2004	0.0087	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	SO2	6/12/2007	0.061	GRAINS PER DRY STANDARD CUBIC FOOT	Heat input limited to 15.77MMBtu/hour (110% testing). Sulfur content determined from fuel.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	SO2	10/23/2006	0.0001	GRAINS PER DRY STANDARD CUBIC FOOT	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	SO2	12/21/2005	0.0029	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	SO2	8/25/2005	0.00571	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	5	Engine 1205: 2000 bhp gas-fired RICE compressor engine	A	SO2	7/13/2004	0.00089	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	SO2	12/21/2005	0.00296	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	SO2	8/24/2005	0.00811	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	SO2	7/12/2004	0.00095	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	SO2	6/12/2003	0.000807	GRAINS PER DRY STANDARD CUBIC FOOT	For Low, Mid-Low, Mid-High & Full Loads.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	SO2	6/12/2007	0.061	GRAINS PER DRY STANDARD CUBIC FOOT	Heat input limited to 15.98MMBtu/hour (110% testing). Sulfur determined from Fuel.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	SO2	11/8/2006	0.077	GRAINS PER DRY STANDARD CUBIC FOOT	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	SO2	12/21/2005	0.0029	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	SO2	8/24/2005	0.01775	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	4	Engine 1204: 2000 bhp gas-fired RICE compressor engine	A	SO2	7/13/2004	0.00089	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	SO2	6/11/2007	0.034	GRAINS PER DRY STANDARD CUBIC FOOT	Heat input limited to 132MMBtu/hour (110% o testing). Sulfur determined by fuel analysis.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	10	FGT Unit No. 1208. New 15,700 bhp gas turbine	A	SO2	10/24/2006	0.09	GRAINS PER DRY STANDARD CUBIC FOOT	DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	12/21/2007	0.0077	GRAINS PER DRY STANDARD CUBIC FOOT	Tested by DeNovo; sulfur determined by fuel analysis; restricted to 129 MMBtu/hr (110% of testing)
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	9/10/2003	0.0082	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	8/23/2005	0.00787	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	12/20/2005	0.00296	GRAINS PER DRY STANDARD CUBIC FOOT	
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	6/11/2007	0.04	GRAINS PER DRY STANDARD CUBIC FOOT	Sulfur content determined from fuel analysis. E input limited to 123MMBtu/hour (110% of test
FLORIDA GAS TRANSMISSION COMPANY	1130037	COMPRESSOR STATION #12	NWD	SANTA ROSA	A	Y	8	Engine 1207: 15,000 bhp gas turbine compressor engine	A	SO2	10/24/2006	0.09	GRAINS PER DRY STANDARD CUBIC FOOT	DeNovo-nv, Inc.
SANTA ROSA ENERGY CENTER, LLC	1130168	SANTA ROSA ENERGY CENTER	NWD	SANTA ROSA	A	Y	1	167MW Gas Combustion Turbine (Phase II Acid Rain Unit)	A	NOX	10/31/2007	7.97	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
SANTA ROSA ENERGY CENTER, LLC	1130168	SANTA ROSA ENERGY CENTER	NWD	SANTA ROSA	A	Y	1	167MW Gas Combustion Turbine (Phase II Acid Rain Unit)	A	NOX	8/1/2003	6.68	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
SANTA ROSA ENERGY CENTER, LLC	1130168	SANTA ROSA ENERGY CENTER	NWD	SANTA ROSA	A	Y	1	167MW Gas Combustion Turbine (Phase II Acid Rain Unit)	A	CO	10/31/2007	0.7	PARTS PER MILLION DRY GAS VOLUME	
SANTA ROSA ENERGY CENTER, LLC	1130168	SANTA ROSA ENERGY CENTER	NWD	SANTA ROSA	A	Y	1	167MW Gas Combustion Turbine (Phase II Acid Rain Unit)	A	CO	8/24/2004	0	PARTS PER MILLION DRY GAS VOLUME	
SANTA ROSA ENERGY CENTER, LLC	1130168	SANTA ROSA ENERGY CENTER	NWD	SANTA ROSA	A	Y	1	167MW Gas Combustion Turbine (Phase II Acid Rain Unit)	A	CO	8/1/2003	1.04	PARTS PER MILLION DRY GAS VOLUME	
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/12/2007	35.6	POUNDS/HOUR	
		COGENERATION												Unit B emissons = 10.872 pph; Limit is 40 pph

GULF POWER COMPANY	1130173	PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/26/2003	39.685	POUNDS/HOUR	combined: heat input limit for each unit is 150 MMBtu/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/26/2003	50.718	POUNDS/HOUR	The 50.718 represents the total NOx emissions the 3 turbines. There is no invidiual limit. The 4 mmbut/hr heat input represents the total from tl units.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/26/2003	50.718	POUNDS/HOUR	The 50.718 represents the total NOx emissions the 3 turbines. There is no invidiual limit. The 4 mmbut/hr heat input represents the total from tl units.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/26/2003	50.718	POUNDS/HOUR	The 50.718 represents the total NOx emissions the 3 turbines. There is no invidiual limit. The 4 mmbut/hr heat input represents the total from tl units.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/26/2003	11.251	POUNDS/HOUR	Unit B emissons= 11.251 pph ;Limit is 40 pph combined:: heat input limit for each unit is 150 MMBtu/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/26/2003	39.685	POUNDS/HOUR	Unit C emissions = 17.562 pph; Limit is 40 pph combined: heat input limit for each unit is 150 MMBtu/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/23/2004	10.936	POUNDS/HOUR	Units A, B, & C in Turbine Mode combine to e 31.964 lb/hr which complies with the limit of 4 lb/hr. Unit A in Turbine Mode and Units B & C Fresh Air Mode combine to emit 50.036 lb/hr v complies with limit of 60 lb/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/19/2004	10.366	POUNDS/HOUR	Units A, B, & C in Turbine Mode combine to e (10.936 + 10.366 + 10.662 =) 31.964 lb/hr whi complies with the limit of 40 lb/hr. Unit A in Turbine Mode and Units B & C in Fresh Air M combine to emit (10.936 + 18.687 + 20.413 =) 50.036 lb/hr which complies with limit of 60 lb
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/18/2004	10.662	POUNDS/HOUR	Units A, B, & C in Turbine Mode combine to e (10.936 + 10.366 + 10.662 =) 31.964 lb/hr whi complies with the limit of 40 lb/hr. Unit A in Turbine Mode and Units B & C in Fresh Air M combine to emit (10.936 + 18.687 + 20.413 =) 50.036 lb/hr which complies with limit of 60 lb
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/22/2004	18.687	POUNDS/HOUR	Units A, B, & C in Turbine Mode combine to e (10.936 + 10.366 + 10.662 =) 31.964 lb/hr whi complies with the limit of 40 lb/hr. Unit A in Turbine Mode and Units B & C in Fresh Air M combine to emit (10.936 + 18.687 + 20.413 =) 50.036 lb/hr which complies with limit of 60 lb
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/18/2004	20.413	POUNDS/HOUR	Units A, B, & C in Turbine Mode combine to e (10.936 + 10.366 + 10.662 =) 31.964 lb/hr whi complies with the limit of 40 lb/hr. Unit A in Turbine Mode and Units B & C in Fresh Air M combine to emit (10.936 + 18.687 + 20.413 =) 50.036 lb/hr which complies with limit of 60 lb
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/22/2005	12.58	POUNDS/HOUR	For Unit A: Ave Temp = 49.9 F. Ave heat inpu 133.6 MMBtu/hr. Total NOx for Units A, B & Normal Mode is 34.58 lbs/hr; compliant with li of 40 lbs/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/21/2005	11.05	POUNDS/HOUR	For Unit B: Ave Temp = 41.9 F. Ave heat inpu 122.2 MMBtu/hr. Total NOx for Units A, B & Normal Mode is 34.58 lbs/hr; compliant with li of 40 lbs/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/14/2005	10.95	POUNDS/HOUR	For Unit C: Ave Temp = 75.4 F. Ave heat inpu 135.7 MMBtu/hr. Total NOx for Units A, B & Normal Mode is 34.58 lbs/hr; compliant with li of 40 lbs/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/21/2005	20.96	POUNDS/HOUR	For Unit B in Fresh Air Mode: Ave heat input = 122.2 MMBtu/hr. Total NOx for Units A, B & Fresh Air Mode 56.17 lbs/hr; compliant with lin 60 lbs/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/17/2005	22.63	POUNDS/HOUR	For Unit C in Fresh Air Mode: Ave heat input = 120.9 MMBtu/hr. Total NOx for Units A, B & Fresh Air Mode 56.17 lbs/hr; compliant with lin 60 lbs/hr.
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/13/2006	11.3	POUNDS/HOUR	
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/16/2006	11.4	POUNDS/HOUR	
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/22/2006	22.6	POUNDS/HOUR	Fresh Air Mode
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/17/2006	12.7	POUNDS/HOUR	
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/21/2006	22.9	POUNDS/HOUR	Fresh Air Mode
GULF POWER COMPANY	1130173	COGENERATION PLANT (PEA RIDGE PLANT)	NWD	SANTA ROSA	A	Y	1	COGENERATION UNITS A,B AND C.	A	NOX	11/15/2007	24.02	POUNDS/HOUR	Team = Gulf Power Field Services
FLORIDA EXTRUDERS INTERNATIONAL INC	1170027	FLORIDA EXTRUDERS INT'L	CD	SEMINOLE	A	Y	12	MELT FURNACE	A	DIOX	5/12/2004	0.15	OTHER (SPECIFY IN COMMENT)	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	SO2	7/19/2006	0	PERCENT BY VOLUME ON A DRY BASIS	See Allow Seq 001. Fuel sulfur content by weig was 0.05%, permit allows .5%, permit conditio B11 & B28. C.E.M. Solutions, Inc. Crystal Riv FL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	SO2	7/20/2006	0.05	OTHER (SPECIFY IN COMMENT)	Fuel sulfur content by weight was 0.05%, perm allows .5%, permit conditions B11 & B28. C.E Solutions, Inc. Crystal River, FL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	SO2	7/15/2003	0.000004	PERCENT BY VOLUME ON A DRY BASIS	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	SO2	7/18/2006	0.3	OTHER (SPECIFY IN COMMENT)	Burning #2 Fuel Oil. Sulfur content analysis.
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	SO2	8/14/2007	0.05	OTHER (SPECIFY IN COMMENT)	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	SO2	7/15/2003	0.000004	PERCENT BY VOLUME ON A DRY BASIS	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	SO2	7/19/2006	0.05	OTHER (SPECIFY IN COMMENT)	Fuel sulfur content by weight was 0.05%, perm allows .5%, permit conditions B11 & B28. C.E Solutions, Inc. Crystal River, FL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	SO2	8/14/2007	0.05	OTHER (SPECIFY IN COMMENT)	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	SO2	8/14/2007	0.05	OTHER (SPECIFY IN COMMENT)	

FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	8/23/2007	0.05	POUNDS PER MILLION BTU HEAT INPUT	CME Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	7/7/2004	0.2	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	8/11/2005	0.06	POUNDS PER MILLION BTU HEAT INPUT	Normal operating mode. No. 6 fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	7/22/2003	0.0608	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	8/3/2004	0.05	POUNDS PER MILLION BTU HEAT INPUT	non-soot blowing
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	8/3/2004	0.09	POUNDS PER MILLION BTU HEAT INPUT	soot blowing
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	8/4/2005	0.08	POUNDS PER MILLION BTU HEAT INPUT	Normal operation. No. 6 fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	8/4/2005	0.1	POUNDS PER MILLION BTU HEAT INPUT	Soot Blowing. No. 6 fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	7/20/2006	0.03	POUNDS PER MILLION BTU HEAT INPUT	Normal operations (non soot blowing). 91% operating rate.
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	7/20/2006	0.04	POUNDS PER MILLION BTU HEAT INPUT	Soot blowing. 91% operating rate. Burning #6 I
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	8/21/2007	0.06	POUNDS PER MILLION BTU HEAT INPUT	CME Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	8/21/2007	0.09	POUNDS PER MILLION BTU HEAT INPUT	CME Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	3	Boiler No. 3(PhaseII Acid Rain Unit)	A	PM	7/22/2003	0.0725	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	7/14/2003	0.0804	POUNDS PER MILLION BTU HEAT INPUT	Normal operating.
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	7/14/2003	0.0919	POUNDS PER MILLION BTU HEAT INPUT	Soot Blowing
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	8/2/2005	0.08	POUNDS PER MILLION BTU HEAT INPUT	Soot Blowing. No. 6 fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	7/7/2004	0.1	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	7/19/2006	0.09	POUNDS PER MILLION BTU HEAT INPUT	Soot blowing. 82% Operating rate. Burning #6
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	8/23/2007	0.09	POUNDS PER MILLION BTU HEAT INPUT	CME Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	1	Boiler No. 1(PhaseII Acid Rain Unit)	A	PM	7/19/2006	0.07	POUNDS PER MILLION BTU HEAT INPUT	Normal operation (Non soot blowing). 82% operating rate.
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	8/22/2007	0.02	POUNDS PER MILLION BTU HEAT INPUT	CME Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	8/22/2007	0.05	POUNDS PER MILLION BTU HEAT INPUT	CME Solutions
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	7/18/2006	0.11	POUNDS PER MILLION BTU HEAT INPUT	Soot blowing. 87% operating rate.
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	7/18/2006	0.1	POUNDS PER MILLION BTU HEAT INPUT	Normal operations (non soot blowing). 86% operating rate. Burning #6 FO
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	7/8/2004	0.1	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	7/8/2004	0.1	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	SO2	7/15/2003	0.00283	PERCENT BY VOLUME ON A DRY BASIS	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	SO2	7/15/2003	0.00279	PERCENT BY VOLUME ON A DRY BASIS	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	SO2	11/18/2003	54	POUNDS/HOUR	limit 379 lb/hr:
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	SO2	11/18/2003	0.003	PERCENT BY VOLUME ON A DRY BASIS	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	SO2	7/20/2006	0	PERCENT BY VOLUME ON A DRY BASIS	See Allow Seq 001. Fuel sulfur content by weig was 0.05%, permit allows .5%, permit conditio B11 & B28. C.E.M. Solutions, Inc. Crystal Riv FL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	8/3/2005	0.1	POUNDS PER MILLION BTU HEAT INPUT	Soot Blowing. No. 6 fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	8/3/2005	0.06	POUNDS PER MILLION BTU HEAT INPUT	Normal operaing mode. No. 6 fuel oil
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	7/22/2003	0.0542	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	2	Boiler No. 2(PhaseII Acid Rain Unit)	A	PM	7/22/2003	0.0884	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	NOX	8/14/2007	55.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	NOX	7/19/2006	61	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Operated at 47.7MW (100%) ..Burning NG. C. Solutions, Inc. 352.564.0441
FLORIDA POWER		FL POWER											PARTS PER	

CORPDBAPROGRESS ENERGY FLA	1210003	SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	NOX	7/15/2003	55	MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	NOX	7/20/2006	59.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Burning NG. Operated at 49.5 MW (99.6%). C Solutions, Inc. Crystal River, FL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	NOX	11/19/2003	60.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	6	CTEG Peaking Unit No. 3(P-3)	A	NOX	8/14/2007	54.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	NOX	7/15/2003	55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	NOX	7/15/2003	63.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	NOX	7/15/2003	65.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	NOX	7/18/2006	70.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Burning #2 Fuel Oil. Operated at 47.3 MW (98 C.E.M. Solutions, Inc. Crystal River, FL
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	5	CTEG Peaking Unit No. 2(P-2)	A	NOX	8/14/2007	67.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	1210003	FL POWER SUWANNEE RVR PLANT	NED	SUWANNEE	A	Y	4	CTEG Peaking Unit No. 1(P-1)	A	NOX	7/15/2003	52.7	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	DIOX	8/16/2006	0.0004	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	DIOX	8/30/2005	0.0021	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	DIOX	7/18/2003	0.01	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	DIOX	7/11/2003	0.011	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	DIOX	3/8/2004	0.237	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	Baghouse inlet temp avg = 278 degrees F.
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	DIOX	8/17/2006	0.0018	NANOGRAMS PER DRY STANDARD CUBIC METER @ 7% O2	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	H114	8/15/2003	192	POUNDS/YEAR	must limit operation to 4424 equivalent hours.
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	6	Clinker and cement processing w/ baghouses	A	PM10	7/16/2003	0.0065	GRAINS PER DRY STANDARD CUBIC FOOT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	8	Coal mill and coal transfer system w/ baghouses	A	PM10	7/18/2003	0.0061	GRAINS PER DRY STANDARD CUBIC FOOT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	PM10	9/22/2004	3.2	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	SO2	9/22/2004	0	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	PM	7/18/2003	1.92	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	PM	7/10/2003	1.29	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	CO	9/23/2004	261	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	5	Clinker cooler w/ ESP	A	PM	7/14/2003	1.22	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	VOC	9/22/2004	10.2	POUNDS/HOUR	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	PM10	7/11/2007	0.017	POUNDS PER TON OF FEED MATERIAL	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	5	Clinker cooler w/ ESP	A	PM	7/12/2007	0.006	POUNDS PER TON OF FEED MATERIAL	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	VOC	7/12/2007	0.04	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	VOC	7/11/2003	0.049	POUNDS PER TON OF PRODUCT	THC test.
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	SO2	8/14/2006	0.013	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	SO2	7/11/2003	0.02	POUNDS PER TON OF PRODUCT	

SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	NOX	8/14/2006	2.07	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	5	Clinker cooler w/ ESP	A	PM10	8/14/2006	0.0102	POUNDS PER TON OF FEED MATERIAL	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	CO	7/11/2003	1.52	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	CO	8/14/2006	1.56	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	CO	7/11/2007	2.04	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	NOX	7/11/2003	2.52	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	NOX	9/22/2004	2.45	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	NOX	7/11/2007	2.3	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	SO2	8/14/2006	0.013	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	SO2	7/11/2007	0.02	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	VOC	8/14/2006	0.04	POUNDS PER TON OF PRODUCT	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	5	Clinker cooler w/ ESP	A	PM	9/17/2004	0.007	POUNDS PER TON OF FEED MATERIAL	
SUWANNEE AMERICAN CEMENT CO.	1210465	SUWANNEE AMERICAN CEMENT	NED	SUWANNEE	A	Y	4	In line kiln/raw mill w/ baghouse - main stack	A	PM10	8/14/2006	0.05	POUNDS PER TON OF FEED MATERIAL	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	SO2	10/23/2007	179.7	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	SO2	9/1/2004	191	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	41	#2 PURIFICATION PLANT	A	H038	5/5/2004	2.6	PARTS PER MILLION DRY GAS VOLUME	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	41	#2 PURIFICATION PLANT	A	H038	3/9/2005	6.99	PARTS PER MILLION DRY GAS VOLUME	Weston Solutions
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	41	#2 PURIFICATION PLANT	A	H038	5/3/2006	8	PARTS PER MILLION DRY GAS VOLUME	The testing was conducted with the process operating at a rate of 900 Tons/Day BDUP.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	41	#2 PURIFICATION PLANT	A	H038	5/16/2007	0.8	PARTS PER MILLION DRY GAS VOLUME	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	41	#2 PURIFICATION PLANT	A	H038	5/3/2006	0.8	PARTS PER MILLION DRY GAS VOLUME	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	10/21/2003	4.8	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	10/25/2005	3.6	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	10/3/2006	23.1	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	10/17/2007	23.3	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	TRS	10/25/2005	0.381	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	SO2	10/30/2003	110.4	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	40	TALL OIL PLANT W/ WET SCRUBBER	A	TRS	5/4/2004	0.17	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	SO2	10/5/2006	121.5	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	SO2	11/8/2005	142.1	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	NOX	5/22/2007	40.11	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	21	#2 SMELT DISSOLVING TANK FOR #2 RB W/WET SCRUBBER	A	PM	4/4/2006	26	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	21	#2 SMELT DISSOLVING TANK FOR #2 RB W/WET SCRUBBER	A	PM	5/7/2007	24.8	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	6	#2 RECOVERY BOILER W/ ESP & TRS BLOX SYS A	A	PM	4/24/2003	13.6	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	6	#2 RECOVERY BOILER W/ ESP & TRS BLOX SYS A	A	PM	4/5/2006	97	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	PM	10/30/2003	26.2	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	PM	9/1/2004	34.7	POUNDS/HOUR	
								#1 BARK BLR						

BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	PM	11/8/2005	33.23	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	PM	10/5/2006	33.4	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	PM	10/23/2007	35.5	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	PM	9/3/2003	0.04	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	PM	7/20/2006	30	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	TRS	7/20/2006	0.9	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	10/22/2003	8.3	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	10/27/2005	16.03	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	10/4/2006	81.8	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	10/16/2007	81.8	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	TRS	5/22/2007	0.59	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	21	#2 SMELT DISSOLVING TANK FOR #2 RB W/WET SCRUBBER	A	TRS	4/11/2006	0.79	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	4	#1 BARK BLR W/CYCLONE & VENTURI SCRBBR COMM STCK W/SRC 2,3,1	A	TRS	10/5/2006	3.38	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	21	#2 SMELT DISSOLVING TANK FOR #2 RB W/WET SCRUBBER	A	PM	4/8/2003	3.8	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	19	#2 BARK BOILER W/CYCLONE & SCRUBBER, COMMON STACK A	A	PM	4/23/2003	73	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	19	#2 BARK BOILER W/CYCLONE & SCRUBBER, COMMON STACK A	A	PM	5/4/2004	88.1	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	19	#2 BARK BOILER W/CYCLONE & SCRUBBER, COMMON STACK A	A	PM	4/20/2005	96.9	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	19	#2 BARK BOILER W/CYCLONE & SCRUBBER, COMMON STACK A	A	PM	5/3/2006	81.42	POUNDS/HOUR	The average PM for 3 Runs was 81.42 lbs/hr.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	19	#2 BARK BOILER W/CYCLONE & SCRUBBER, COMMON STACK A	A	PM	5/24/2007	80.6	POUNDS/HOUR	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	10/7/2004	0.0084	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	11	#4 RECOVERY BLR,LOW ODOR DESIGN,ELECTROSTATIC PREC.FOR PM CO	A	PM	9/9/2004	0.0226	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	11	#4 RECOVERY BLR,LOW ODOR DESIGN,ELECTROSTATIC PREC.FOR PM CO	A	PM	3/29/2004	0.0169	GRAINS PER DRY STANDARD CUBIC FOOT	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	11	#4 RECOVERY BLR,LOW ODOR DESIGN,ELECTROSTATIC PREC.FOR PM CO	A	PM	7/18/2006	0.0194	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	6	#2 RECOVERY BOILER W/ ESP & TRS BLOX SYS A	A	PM	4/6/2004	0.0083	GRAINS PER DRY STANDARD CUBIC FOOT	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	6	#2 RECOVERY BOILER W/ ESP & TRS BLOX SYS A	A	PM	5/8/2007	0.0189	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	11	#4 RECOVERY BLR,LOW ODOR DESIGN,ELECTROSTATIC PREC.FOR PM CO	A	PM	9/8/2003	0.0226	POUNDS PER 3000 POUNDS BLACK LIQUOR SOLIDS	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	2	#1 PWR BLR #6 FO/NAT GAS 250 MMBTU COMM STK W/SRC 3,4,19 A1A	A	TRS	3/9/2005	1.3	PARTS PER MILLION DRY GAS VOLUME @ 10% O2	Weston Solutions, Auburn Alabama
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	6	#2 RECOVERY BOILER W/ ESP & TRS BLOX SYS A	A	PM	4/6/2005	0.0206	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	11	#4 RECOVERY BLR,LOW ODOR DESIGN,ELECTROSTATIC PREC.FOR PM CO	A	PM	8/15/2007	0.024	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	11	#4 RECOVERY BLR,LOW ODOR DESIGN,ELECTROSTATIC PREC.FOR PM CO	A	PM	10/31/2005	0.0238	GRAINS PER DRY STANDARD CUBIC FOOT	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	3/30/2004	0.0073	GRAINS PER DRY STANDARD CUBIC FOOT	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	7	#3 RECOVERY BOILER W/1 dry ESP & BLOX A	A	PM	10/27/2005	0.027	GRAINS PER DRY STANDARD CUBIC FOOT	

BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	10/6/2004	0.092	POUNDS PER TON BLACK LIQUOR SOLIDS	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	PM	9/8/2004	0.0765	POUNDS PER TON BLACK LIQUOR SOLIDS	4.5 lbs/hr (PM) / 58.8 T/hr (BLS) = 0.0765 Pou per Ton BLS
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	PM	11/1/2005	0.038	POUNDS PER TON BLACK LIQUOR SOLIDS	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	21	#2 SMELT DISSOLVING TANK FOR #2 RB W/WET SCRUBBER	A	PM	4/5/2004	0.08	POUNDS PER TON BLACK LIQUOR SOLIDS	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	21	#2 SMELT DISSOLVING TANK FOR #2 RB W/WET SCRUBBER	A	PM	4/5/2005	0.041	POUNDS PER TON BLACK LIQUOR SOLIDS	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	PM	8/14/2007	0.0236	POUNDS PER TON BLACK LIQUOR SOLIDS	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	23	#4 SMELT DISSOLVING TANK W/WET SCRUBBER CONTROL	A	PM	3/29/2004	0.1	POUNDS PER TON BLACK LIQUOR SOLIDS	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	PM	4/25/2005	0.0107	GRAINS PER DRY STANDARD CUBIC FOOT @ 10% O2	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	PM	4/6/2004	0.0045	GRAINS PER DRY STANDARD CUBIC FOOT @ 10% O2	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	PM	3/10/2006	0.0159	GRAINS PER DRY STANDARD CUBIC FOOT @ 10% O2	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	PM	11/10/2005	0.0228	GRAINS PER DRY STANDARD CUBIC FOOT @ 10% O2	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	PM	11/3/2005	0.0114	GRAINS PER DRY STANDARD CUBIC FOOT @ 10% O2	ESP normal operation
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	24	#4 LIME KILN W/ ESP FOR PM & TRS CEMS A	A	PM	5/22/2007	0.0082	GRAINS PER DRY STANDARD CUBIC FOOT @ 10% O2	
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	3/30/2004	0.14	POUNDS PER TON BLACK LIQUOR SOLIDS	MACT II intial performance test. Chemical Recovery Process under 40 CFR 63 Subpart MI PM-HAPS.
BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	NED	TAYLOR	A	Y	22	#3 SMELT DISSOLVING TANK FOR #3 RB W/WET SCRUBBER	A	PM	10/25/2005	0.0306	POUNDS PER TON BLACK LIQUOR SOLIDS	
GILMAN BUILDING PRODUCTS	1230033	GILMAN BUILDING PRODUCTS	NED	TAYLOR	A	Y	1	Wood Fired Boiler w/ two multi-cyclone collectors in series	A	PM	6/25/2003	0.2	POUNDS PER MILLION BTU HEAT INPUT	Boiler fired with 5.28 TPH of wood waste. PM 8.70 lb/hr, allowable is 9.20 lb/hr
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	6/18/2007	15.75	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input 64.20 mmbtu/hr. Fuel rate 57,542 sc DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	8/16/2005	13.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	11/25/2003	15.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	1/7/2003	14.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	CO	5/22/2006	11.78	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	12867 BHP. 110.25 mmbtu/hr. DeNovo-nv, Inc 1544 Sawdust Rd., Suite 302, The Woodlands, 77380. (281) 298-2550. Louis M. Esposito, Pro Mgr.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	CO	9/3/2003	5.34	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	6/18/2007	1.44	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input 64.20 mmbtu/hr. Fuel rate 57,542 sc DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	10/19/2004	11.76	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	NOX	4/20/2004	19.4	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	NOX	9/3/2003	14.1	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	NOX	8/16/2005	13.2	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	NOX	5/22/2006	14.35	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	12867 BHP. 110.25 mmbtu/hr. DeNovo-nv, Inc 1544 Sawdust Rd., Suite 302, The Woodlands, 77380. (281) 298-2550. Louis M. Esposito, Pro Mgr.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	NOX	6/18/2007	20.19	PARTS PER MILLION DRY GAS VOLUME	Heat input 64.20 mmbtu/hr. Fuel rate 57,542 sc DeNovo-nv, Inc.

													@ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	1/7/2003	4.87	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	1/7/2003	4.87	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	11/25/2003	6.71	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	8/16/2005	6.31	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	CO	5/23/2006	7.05	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	6306 BHP. 59.12 mmbtu/hr. DeNovo-nv, Inc. 1 Sawdust Rd., Suite 302, The Woodlands, TX 7 (281) 298-2550. Louis M. Esposito, Project Mg
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	CO	4/20/2004	2.79	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	CO	8/16/2005	8.18	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	6	15,000 bhp gas turbine compressor engine (FGT 1507)	A	CO	6/18/2007	0.35	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Heat input 64.20 mmbtu/hr. Fuel rate 57,542 sc DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	1/7/2003	14.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	5/23/2006	13.79	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	6306 BHP. 59.12 mmbtu/hr. DeNovo-nv, Inc. 1 Sawdust Rd., Suite 302, The Woodlands, TX 7 (281) 298-2550. Louis M. Esposito, Project Mg
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	4	7222 bhp gas turbine compressor engine (FGT Unit 1508)	A	NOX	10/19/2004	12.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	CO	6/19/2007	8.9	POUNDS/HOUR	Heat input 26.33 mmbtu/hr. Fuel rate 25,474 sc DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	SO2	6/19/2007	0.003	POUNDS/HOUR	Heat input 26.33 mmbtu/hr. Fuel rate 25,474 sc DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	SO2	10/1/2004	0.00534	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	NOX	9/3/2003	3.89	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	NOX	8/16/2005	11.45	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	NOX	10/1/2004	7.39	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	NOX	5/23/2006	10.27	POUNDS/HOUR	3772 BHP. 26.85 mmbtu/hr. DeNovo-nv, Inc. 1 Sawdust Rd., Suite 302, The Woodlands, TX 7 (281) 298-2550. Louis M. Esposito, Project Mg
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	NOX	6/19/2007	9.63	POUNDS/HOUR	Heat input 26.33 mmbtu/hr. Fuel rate 25,474 sc DeNovo-nv, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	SO2	9/3/2003	0.00487	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	SO2	8/16/2005	0.00985	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	SO2	5/23/2006	0.0052	POUNDS/HOUR	3772 BHP. 26.85 mmbtu/hr. DeNovo-nv, Inc. 1 Sawdust Rd., Suite 302, The Woodlands, TX 7 (281) 298-2550. Louis M. Esposito, Project Mg
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	CO	5/23/2006	8.59	POUNDS/HOUR	3772 BHP. 26.85 mmbtu/hr. DeNovo-nv, Inc. 1 Sawdust Rd., Suite 302, The Woodlands, TX 7 (281) 298-2550. Louis M. Esposito, Project Mg
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	CO	10/1/2004	10.9	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	CO	8/16/2005	8.5	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1230034	FL GAS-STATION 15	NED	TAYLOR	A	Y	2	1506 RECIPROCATING I.C. ENGINE, 4000 BHP NATURAL GAS FIRED	A	CO	9/3/2003	16.58	POUNDS/HOUR	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	VOC	2/21/2003	0.3	PARTS PER MILLION DRY GAS VOLUME	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	VOC	2/12/2003	0.12	PARTS PER MILLION DRY GAS VOLUME	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	VOC	2/23/2003	0.17	OTHER (SPECIFY IN COMMENT)	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/21/2004	6.82	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/21/2003	7.9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	5/24/2005	8.55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/27/2004	6.78	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER &		SANFORD POWER						Unit PSNCT5A Combined					PARTS PER MILLION DRY	

LIGHT (PSN)	1270009	PLANT	CD	VOLUSIA	A	Y	9	Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	1.6	GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	1.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences 1 2 as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	piping for oil firing has not been completed. oil not been fired.
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/24/2005	1.39	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/26/2004	1.44	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/8/2006	1.44	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/8/2006	1.44	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/8/2006	1.44	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	2/14/2003	8.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostradi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	5/31/2005	8.66	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/19/2004	7.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	6/4/2003	1.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	6/24/2003	1.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences 1 2 as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	piping for oil firing has not been completed. oil not been fired.
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/26/2005	1.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/28/2004	1.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/10/2006	1.42	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/10/2006	1.42	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/10/2006	1.42	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	2/23/2003	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	6/2/2005	8.66	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/21/2004	7.07	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/23/2003	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/23/2003	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	6/2/2005	1.59	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2004	1.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/3/2006	1.29	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	8	Unit PSNCT4D Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/3/2006	1.29	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/9/2006	1.43	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/9/2006	1.43	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
								Unit PSNCT4A Combined					PARTS PER	

FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Cycle CT with unfired HRSG (250 MW)	A	CO	2/12/2003	0.6	MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/12/2003	0.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/13/2005	1.59	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/19/2004	1.83	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/1/2006	1.55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	5	Unit PSNCT4A Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/1/2006	1.33	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	6/4/2003	9	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	2/21/2003	8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	6/1/2005	8.68	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/20/2004	7.47	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team. High Temperature peaking load test also conducted. NOx/hr at ISO conditions
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/21/2003	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostradi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	6/1/2005	1.63	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/20/2004	1.68	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/1/2006	4.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/1/2006	1.23	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/12/2003	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/12/2003	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostradi Platt, CO tested at 100% load
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	6/1/2005	1.71	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2004	1.56	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	6	Unit PSNCT4B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	2/21/2003	0.5	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/2/2006	1.41	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/2/2006	1.39	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	1.66	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	1.66	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences 1 2 as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	piping for oil firing has not been completed. oil not been fired.
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/25/2005	1.52	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/27/2004	1.54	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/9/2006	1.43	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	5/26/2005	8.39	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	12	Unit PSNCT5D Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/28/2004	7.62	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team

FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/21/2003	6.91	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	5/25/2005	8.55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	11	Unit PSNCT5C Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/27/2004	7.01	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/21/2003	7.74	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	5/24/2005	8.78	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Flordia Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	9	Unit PSNCT5A Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	4/26/2004	7.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	1.49	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	FP&L Technical Services
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	1.49	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Same stack test for both allowable sequences 1 2 as allowed by the permit
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/21/2003	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	piping for oil firing has not been completed. oil not been fired.
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/24/2005	1.42	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	4/27/2004	1.56	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light stack test team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/9/2006	1.55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/9/2006	1.55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	10	Unit PSNCT5B Combined Cycle CT with unfired HRSG (250 MW)	A	CO	5/9/2006	1.55	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	6/1/2005	8.61	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Florida Power and Light Test Team
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	NOX	2/12/2003	7.8	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Mostardi Platt, Test conducted at 4 loads, a is at 100% load
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	7	Unit PSNCT4C Combined Cycle CT with unfired HRSG (250 MW)	A	VOC	2/12/2003	0.1	POUNDS PER MILLION BTU HEAT INPUT	GE Mostardi Platt
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/29/2007	0.06	POUNDS PER MILLION BTU HEAT INPUT	FP&L Test Group
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/29/2007	0.05	POUNDS PER MILLION BTU HEAT INPUT	FP&L Test Group
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/17/2004	0.07	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/17/2004	0.06	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/8/2006	0.05	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/8/2006	0.05	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/30/2005	0.04	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/30/2005	0.04	POUNDS PER MILLION BTU HEAT INPUT	
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/19/2003	0.07	POUNDS PER MILLION BTU HEAT INPUT	FP&L Technical Services, Fuel additive used a rate of 3.5 gal/hr
FLORIDA POWER & LIGHT (PSN)	1270009	SANFORD POWER PLANT	CD	VOLUSIA	A	Y	1	Fossil Fuel Steam Generator Unit 3 (Phase II Acid Rain Unit)	A	PM	8/19/2003	0.06	POUNDS PER MILLION BTU HEAT INPUT	FP&L Technical Services, Fuel additive used a rate of 3.5 gal/hour
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	NOX	6/14/2006	5.49	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	SO2	6/16/2004	0.241	PERCENT SULFUR IN FUEL	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	SO2	6/17/2003	0.207	PERCENT SULFUR IN FUEL	Progress Energy Environmental Tesat Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	SO2	6/14/2005	0.22	PERCENT SULFUR IN FUEL	Fuel is oil. Stack test team is CEM Solutions
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	NOX	6/17/2004	40.15	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	6/8/2006	3.29	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	

FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	SO2	6/19/2003	0.258	PERCENT SULFUR IN FUEL	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	SO2	6/16/2005	0.2	PERCENT SULFUR IN FUEL	Fuel is oil. Stack test team is CEM Solutions
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	SO2	6/17/2004	0.232	PERCENT SULFUR IN FUEL	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/17/2003	35.59	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/13/2003	18.27	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Enmergy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/14/2005	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	RA 1.84%, CEM Solutions
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/16/2004	39.85	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/17/2004	19.93	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team, nat gas firing
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/13/2006	6.34	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	NOX	6/14/2006	6.34	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	6/23/2003	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	6/13/2003	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	6/23/2003	19.12	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	4/6/2004	20.96	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progresss Energy Stack Test Group
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	6/14/2005	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Relative Accuracy 5.07 % compliance by CEM
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	NOX	6/14/2004	40.22	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	NOX	6/11/2003	37.3	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	NOX	6/11/2003	18.31	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	NOX	6/21/2005	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Compliance by CEM 4.89% RA
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	NOX	6/9/2004	41.13	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	GE Frame 7EA firing natural gas or fuel oil, tes by Progress Energy Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	NOX	6/9/2004	18.69	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress Energy Environmental Test Team, nat gas firing
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	NOX	6/8/2006	0.006	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	SO2	6/11/2003	0.208	PERCENT SULFUR IN FUEL	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	SO2	6/9/2004	0.241	PERCENT SULFUR IN FUEL	GE Frame 7EA firing natural gas or fuel oil, tes by Progress Energy Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	SO2	6/14/2004	0.232	PERCENT SULFUR IN FUEL	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	NOX	6/16/2005	0	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Fuel is gas. Stack test team is CEM Solutions. Realative Accuracy is 1.84%
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	NOX	6/19/2003	30.6	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Progress energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	CO	6/14/2005	1.99	POUNDS/HOUR	Tested by CEM Solutions
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	CO	4/6/2004	2.1	POUNDS/HOUR	Progress Energy Stack Test Group, firing gas
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	16	Combustion Turbine # 8 (Phase II Acid Rain Unit)	A	CO	6/23/2003	2.399	POUNDS/HOUR	Progresss Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	CO	6/9/2004	0.142	POUNDS/HOUR	GE Frame 7EA firing natural gas or fuel oil, tes by Progress Energy Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	Combustion Turbine # 7 (Phase II Acid Rain Unit)	A	CO	6/21/2005	0.31	POUNDS/HOUR	CEM solutions fuel oil
FLORIDA POWER								Combustion Turbine # 7						

CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	15	(Phase II Acid Rain Unit)	A	CO	6/11/2003	0.398	POUNDS/HOUR	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	CO	6/19/2003	2.386	POUNDS/HOUR	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	CO	6/16/2005	1	POUNDS/HOUR	Fuel is oil. Stack test team is CEM Solutions
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	CO	6/17/2004	0.829	POUNDS/HOUR	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	18	Combustion Turbine # 10 (Phase II Acid Rain Unit)	A	CO	6/13/2006	1.49	POUNDS/HOUR	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	CO	6/13/2006	1.92	POUNDS/HOUR	
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	CO	6/16/2004	0.019	POUNDS/HOUR	Progress Energy Environmental Test Team
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	CO	6/14/2005	7.3	POUNDS/HOUR	Fuel is gas. CEM Solutions
FLORIDA POWER CORPORATION D/B/A PROGRESS	1270028	DEBARY FACILITY	CD	VOLUSIA	A	Y	17	Combustion Turbine # 9 (Phase II Acid Rain Unit)	A	CO	6/13/2003	1.513	POUNDS/HOUR	Progress Energy Environmental Test Team
TALLAHASSEE CITY PURDOM GENERATING STA.	1290001	TALLAHASSEE CITY PURDOM GENERATING STA.	NWDT	WAKULLA	A	Y	14	Combustion Turbine-Unit No. 8 (Phase II Acid Rain Unit)	A	CO	9/9/2006	0.294	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	Spectrum Systems, Inc. Operation at max capac not required for CO test (Permit Conditon F.34
TALLAHASSEE CITY PURDOM GENERATING STA.	1290001	TALLAHASSEE CITY PURDOM GENERATING STA.	NWDT	WAKULLA	A	Y	14	Combustion Turbine-Unit No. 8 (Phase II Acid Rain Unit)	A	CO	9/7/2005	0.426	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
TALLAHASSEE CITY PURDOM GENERATING STA.	1290001	TALLAHASSEE CITY PURDOM GENERATING STA.	NWDT	WAKULLA	A	Y	14	Combustion Turbine-Unit No. 8 (Phase II Acid Rain Unit)	A	CO	9/3/2004	0.238	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	SPECTRUM SYSTEMS, INC.
TALLAHASSEE CITY PURDOM GENERATING STA.	1290001	TALLAHASSEE CITY PURDOM GENERATING STA.	NWDT	WAKULLA	A	Y	14	Combustion Turbine-Unit No. 8 (Phase II Acid Rain Unit)	A	CO	9/3/2003	0.395	PARTS PER MILLION DRY GAS VOLUME @ 15% O2	
ST. MARKS POWDER, INC. A GENERAL DYNAMIC	1290003	ST. MARKS POWDER, INC	NWDT	WAKULLA	A	Y	12	Propellant Surface Coating Operations	A	VOC	7/29/2003	0.52	POUNDS/HOUR	Ecology and Environment, Inc.
ST. MARKS POWDER, INC. A GENERAL DYNAMIC	1290003	ST. MARKS POWDER, INC	NWDT	WAKULLA	A	Y	12	Propellant Surface Coating Operations	A	VOC	6/10/2003	10.27	POUNDS/HOUR	Ecology and Environment, Inc.
ST. MARKS POWDER, INC. A GENERAL DYNAMIC	1290003	ST. MARKS POWDER, INC	NWDT	WAKULLA	A	Y	12	Propellant Surface Coating Operations	A	VOC	6/11/2003	22.63	POUNDS/HOUR	Ecology and Environment, Inc.
ST. MARKS POWDER, INC. A GENERAL DYNAMIC	1290003	ST. MARKS POWDER, INC	NWDT	WAKULLA	A	Y	12	Propellant Surface Coating Operations	A	VOC	6/10/2003	7.96	POUNDS/HOUR	Ecology and Environment, Inc.
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	CO	6/20/2007	9.62	POUNDS/HOUR	DeNovo-nv, Inc. performed the testing
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	CO	5/24/2006	8.29	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	CO	6/20/2005	8.08	POUNDS/HOUR	Ambient Temp = 68.5 degrees F
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	CO	7/15/2004	8.87	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	NOX	9/9/2003	3.48	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	NOX	7/15/2004	5.44	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	NOX	6/20/2005	5.12	POUNDS/HOUR	Ambient Temp = 68.5 degrees F
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	NOX	5/24/2006	5.62	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	NOX	6/20/2007	4.42	POUNDS/HOUR	DeNovo-nv, Inc. performed the testing
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	CO	9/9/2003	9.1	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	SO2	6/20/2007	0.003	POUNDS/HOUR	DeNovo-nv, Inc. performed the testing. Sulfur emissions were determined by fuel analysis (all goes is emitted).
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	SO2	5/24/2006	0.0062	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	SO2	6/20/2005	0.0073	POUNDS/HOUR	Ambient Temp = 68.5 degrees F
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	SO2	7/15/2004	0.00383	POUNDS/HOUR	
FLORIDA GAS TRANSMISSION COMPANY	1330005	COMPRESSOR STATION 13	NWD	WASHINGTON	A	Y	6	RECIPROCATING INTERNAL COMBUSTION ENGINE NO.6, 2700 BHP	A	SO2	9/9/2003	0.00479	POUNDS/HOUR	

A Grand Total of 8993 Records were returned.

select OWNER,AIRSID,NAME,FACILITY_OFFICE,FAC_COUNTY_NAME,FACILITY_STATUS,TITLE_V,EU_NO,EU_DESCRIPTION,EU_STATUS,POLLUTANT,TEST_DATE,ACTUAL,UNIT_DESC,COMMENTS from Arms_Snap.POLL_TEST_VW where 1 = 1 AND UPPER(TITLE_V) = 'Y' AND TEST_DATE > TO_DATE('12/31/2002', 'MM/DD/YYYY') order by AIRSID

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Revised: August 29, 2003

Final Technical Report
for the
JEA Large-Scale CFB Combustion Demonstration Project

Submitted to
U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory (NETL)
Pittsburgh, Pennsylvania 15236
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Building Community

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1.0 OVERVIEW

JEA is the largest public power company in Florida and the eighth largest public power company in the US, and is currently serving over 360,000 customers. Prior to the JEA Large-Scale CFB Demonstration Project, JEA's Northside Generating Station (NGS) consisted of three oil/gas-fired steam electric generating units. NS Units 1 and 2 were each nominally rated at 275 megawatts (MW) and Unit 3 at 518 MW. Units 1 and 3 had been in service since 1966 and 1977 respectively. Unit 2 was completed in 1972, but had been inoperable since about 1983 due to major boiler problems.

As part of its Integrated Resource Planning Study in 1996, JEA concluded that additional base load capacity was needed to support Jacksonville's growing need for energy. The optimum source for that additional capacity was repowering NS Unit 2 with a nominal 300 MW state-of-the-art atmospheric circulating fluidized bed (CFB) boiler fueled by coal and/or petroleum coke. In order to provide the project with an overall environmental benefit, increase the economies of scale, and further diversify JEA's overall fuel mix, a decision was made to repower NS Unit 1 with an identical CFB boiler as well. The environmental benefits included a reduction in emissions of nitrogen oxides, sulfur oxides and particulate matter by at least 10% compared to 1994/95 levels while increasing the net plant capacity by 250%.

In early 1997, detailed Condition Assessments of Unit 1 and Unit 2 Balance of Plant (BOP) equipment and systems were conducted by JEA and Black & Veatch (B&V). The results of these assessments indicated that both Unit 1 and Unit 2 were good candidates for repowering and capable of operating for an additional twenty years, provided various equipment and system upgrades were made.

In April 1997, JEA's Board approved the project and authorized staff to proceed with contract negotiations and environmental permitting. Contract negotiations were subsequently initiated with Foster Wheeler (FW) and the United States Department of Energy (DOE) for participation in cost sharing for the first unit (Unit 2) as a Large-Scale CFB Combustion Demonstration Project. Cooperative Agreement DE-FC21-90MC27403 between JEA and the DOE was finalized in September 1997. The Agreement provided for cost sharing based on a total approved project budget of $305,773,774. This represented a DOE cost share of $73,072,464, with the remainder of the project cost paid by JEA.

Environmental permitting work was initiated by FW Environmental in the latter part of 1997. The permitting work, and associated preliminary engineering, proceeded through 1998, and early 1999. FW began detailed engineering for the Boiler Island, including the Air Quality Control System (AQCS), Chimney, and Limestone Preparation System, in December 1998. B&V began detailed engineering for BOP systems, including the Fuel Handling System, in February 1999. Permits necessary to begin construction were issued in July 1999 with site clearing and construction beginning in August 1999.

Initial synchronization of Unit 2 occurred on February 19, 2002, and initial synchronization of Unit 1 occurred on May 29, 2002.

The purpose of this report is to provide a technical account of the total work performed for the project under the Cooperative Agreement between JEA and the DOE. Although the DOE participation was only in the Unit 2 and Common Facilities portion of the project, the project execution by JEA included design and construction for repowering of Unit 1 in the same time frame. Thus, while this report is primarily for Unit 2 and Common Facilities, it also contains some summary type information for the entire Unit 1 and 2 Repowering Project.

1.1 Awards and Reports

The Northside Repowering Project received the 2002 Powerplant Award from Power magazine. In addition, during design and construction, a number of papers were presented on the JEA Large-Scale CFB Demonstration Project at various conferences.

The Cooperative Agreement between DOE and JEA stipulated that a number of reports be prepared to document and summarize various aspects of the Demonstration Project. Following is a listing of the reports that were developed:

Title
Detailed Public Design Report
Start-up Modifications Report
Topical Report 22: The JEA Large-Scale CFB Combustion Demonstration Project
Topical Report: Air Quality Control System
Topical Report: Ash Processing System
Fuel Capability Demonstration Test Report 1: 100% Pittsburgh 8 Coal Fuel
Fuel Capability Demonstration Test Report 2: 50/50 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel
Fuel Capability Demonstration Test Report 3: 100% Illinois 6 Coal Fuel
Fuel Capability Demonstration Test Report 4: 80/20 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel
Final Technical Report (this report)

The above reports are available on the DOE Clean Coal Technology Compendium website at the following link:

http://www.netl.doe.gov/cctc/resources/library/bibliography/demonstration/aepg/baepgfb_jackea.html

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Generally, at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references typically use the abbreviation only.

Abbreviation	Definition
AQCS	Air Quality Control System
B&V	Black & Veatch Corporation
BOP	Balance of Plant
BSA	Byproduct Storage Area
Btu	British Thermal Unit

Abbreviation	Definition
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
CAE	Clean Air Engineering
CaO	Lime
Ca:S	Calcium to Sulfur Ratio
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CY	Calendar Year
DAF	Dry, ash free
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
EAF	Equivalent Availability Factor
F	Fluorine or Degrees Fahrenheit
FF	Fabric Filter
FGS	Fluor Global Services
FW	Foster Wheeler
FWEC	Foster Wheeler Energy Corporation
FWUSA	Foster Wheeler USA
GAG	Gross Actual Generation
GCF	Gross Capacity Factor
GE	General Electric
GOF	Gross Output Factor
GPD	Gallons per Day

Abbreviation	Definition
gpm	gallons per minute
HF	Fluoride
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
HRA	Heat Recovery Area
ID	Induced Draft
IP	Intermediate Pressure
lb	Pounds
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
lb/TBtu	pounds per trillion Btu
LP	Low Pressure
MCR	Maximum Continuous Rating
MFT	Master Fuel Trip
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MgO	Magnesium Oxide
MMBtu	Million Btu
MW	Megawatts
MWh	Megawatt-hour
NCF	Net Capacity Factor
NERC	North American Electric Reliability Council
NGS	Northside Generating Station
NH_3	Ammonia
NOF	Net Operating Factor

Abbreviation	Definition
NO_x	Oxides of Nitrogen
NS	Northside
O&M	Operations and Maintenance
PA	Primary Air
Pb	Lead
PGT	Power Generation Technologies
PI	Plant Information
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
SA	Secondary Air
SDA	Spray Dryer Absorber
SH	Service Hours
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TG	Turbine Generator
tph	tons per hour
TWIP	Turbine Water Induction Prevention
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Carbon

Abbreviation	Definition
WAPC	Wheelabrator Air Pollution Control
WWGay	W.W. Gay Mechanical Contractor
ZCC	Zachry Construction Corp.

2.0 PROJECT HISTORY

2.1 Background

In September 1997, the U.S. DOE and JEA entered into an agreement to repower JEA's Northside Generating Station Unit 2 with CFB boiler technology from FW. The purpose of this agreement was to demonstrate CFB technology for coal firing in large-scale applications while providing increased plant electric output, reduced emissions and broad fuel flexibility.

CFB technology is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows sulfur dioxide (SO_2) capture via limestone injection while minimizing oxides of nitrogen (NO_x) emissions. The technology is flexible enough to handle a wide range of coals as well as petroleum coke and blends of coal and coke. CFB boilers have been installed in smaller, industrial-size plants but have only recently been considered for larger utility power plants. The DOE helped test a 110 MW CFB boiler at a power station in Colorado in one of its earliest and most successful Clean Coal Technology projects. At nearly 300 MW each, the JEA CFB boilers more than double the size of the Colorado unit and are among the world's largest.

The JEA Large-Scale CFB Demonstration Project involved repowering Northside (NS) Unit 2, an existing 275 MW oil/gas fired boiler which had been out of service since the early 80's, with a 297.5 MW CFB boiler. The DOE contributed approximately $73 million from the Clean Coal Technology Program, and JEA provided the remainder of the total budget. The DOE cost sharing included two years of demonstration test runs, during which both coal and coal/petroleum coke blends were fired. JEA also repowered Northside Unit 1 with an identical CFB boiler. The DOE did not cost share in the Unit 1 repowering.

2.2 Project Organizational Structure

JEA contracted with FW to supply the extended boiler island scope of the project. Foster Wheeler Energy Corporation (FWEC) provided the design and supply of the CFB boilers. Foster Wheeler USA (FWUSA) provided engineering, procurement, and construction management services on a cost reimbursable basis for installation of the boilers and for furnishing and erecting the air pollution control systems, chimney, limestone preparation system, and ash handling systems. Foster Wheeler Environmental Corporation, a subsidiary of FWUSA, provided environmental permitting services.

The remaining portions of the project were implemented by JEA staff and supplemented by B&V through a pre-existing Alliance with JEA for engineering services. Procurement, construction and related services were provided through other pre-existing Alliances between JEA and Zachry Construction Corporation (ZCC), Fluor Global Services (FGS), W.W. Gay Mechanical Contractor, Inc.(WWGay), and Williams Industrial Services Inc. This work included upgrades of the existing turbine island equipment, construction of the receiving and handling facilities for the fuel and reagent required for solid fuel firing, upgrading of the electrical switchyard facilities, and construction of an ash management system.

2.3 Project Scope

The project involved the construction and operation of two CFB boilers fueled by coal and petroleum coke to repower two existing steam turbines, each generating nearly 300 MW. CFB boilers are generally capable of removing over 98% of SO_2. However, to improve the overall economics and environmental performance, a polishing scrubber was included to minimize reagent consumption while firing petroleum coke containing up to 8.0% sulfur. The relatively low furnace operating temperature of about 1600° F inherently results in appreciably lower NO_x emissions compared to conventional coal-fired power plants. However, the project also included a new selective non-catalytic reduction (SNCR) system to further reduce emissions of NO_x. Over 99.8% of particulate emissions are removed by a baghouse.

In addition to the CFB combustor and the air pollution control systems, new equipment for the project included a chimney as well as fuel, limestone, and ash handling systems. The project also required overhaul and/or upgrades of existing systems such as the steam turbines, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the plant control systems.

New construction associated with the Repowering Project occupies approximately seventy-five acres of land at the Northside Generating Station (see the Site Arrangement Drawing and Overall Plot Plan in Appendix A). Solid fuel delivery to the site required new receiving, handling, and storage facilities. Limestone and ash storage and handling facilities were also required. Wherever possible, existing facilities and infrastructure were used for the project. These include the intake and discharge system for cooling water, the wastewater treatment system, and the electric transmission lines and towers.

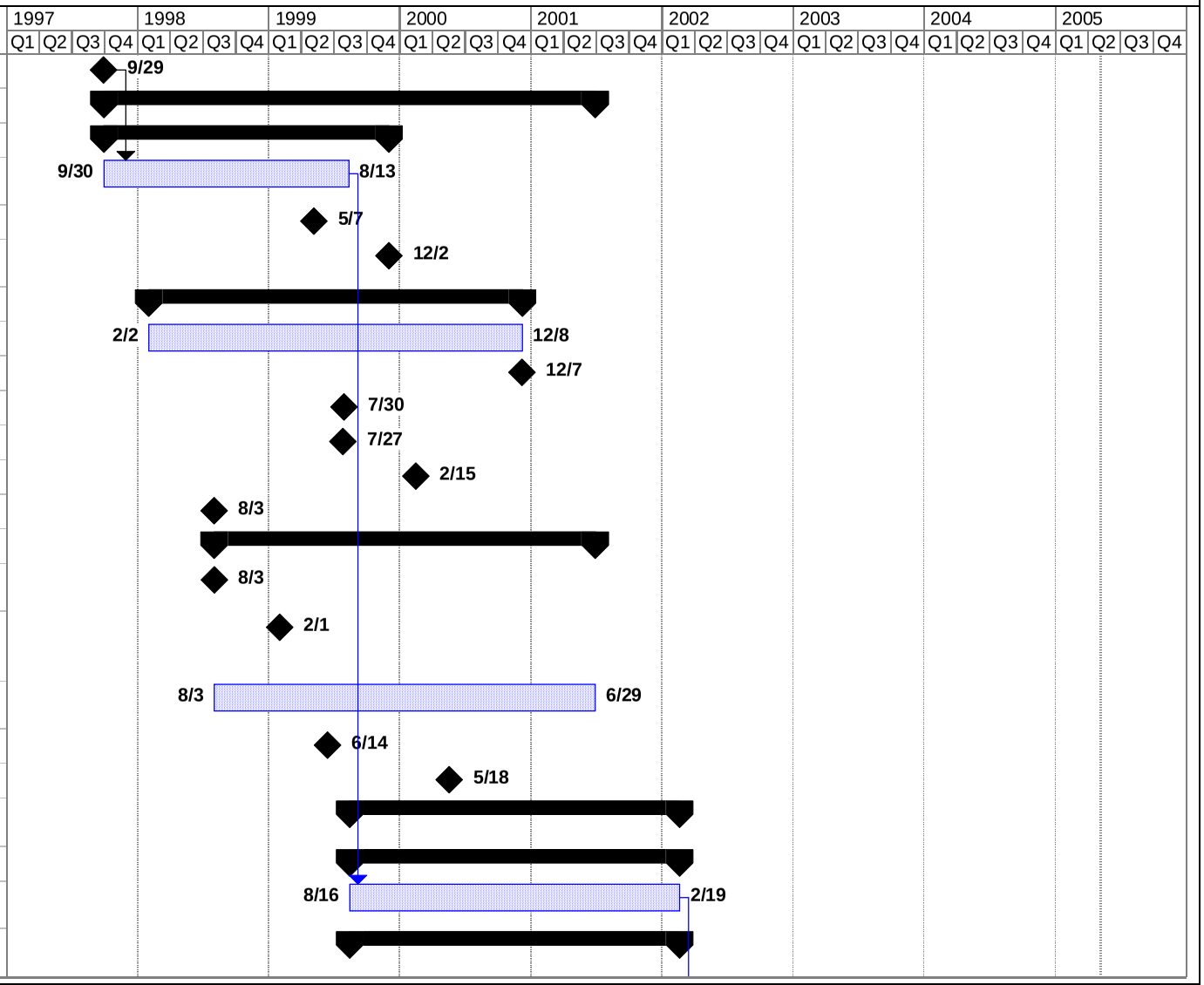
Project activities included engineering and design, permitting, equipment procurement, construction, start-up, and demonstration of the commercial feasibility of the technology. During the demonstration period, Unit 2 was operated under normal dispatch conditions and also tested on several different types of coal and coal/petroleum coke blends to demonstrate the viability of the technology. Units 1 and 2 continue to operate successfully to provide a significant portion of JEA‘s power generation.

2.4 Summary Project Schedule

The Summary Project Schedule on the following pages illustrates the major project activities and milestones for the JEA Large-Scale CFB Combustion Demonstration Project, from the signing of the Cooperative Agreement between DOE and JEA in September 1997 through the conclusion of this DOE Demonstration Project.

JEA Northside Unit 2 Repowering
Summary Project Schedule

ID	Task Name
1	Cooperative Agreement Signed
2	**DOE Phase 1 - Design**
3	**Project Management**
4	Project Management - Phase 1
5	Project Management Plan
6	Environmental Monitoring Plan
7	**Permitting**
8	Overall Permitting Activities
9	NEPA Completion
10	FACE Water Permit
11	ERP Permit
12	NPDES Water Permit
13	**Preliminary Design Complete**
14	**Design Engineering**
15	NTP - Boiler/AQCS Engineering
16	NTP - Balance of Plant & Material Handling Engineering
17	Detailed Design Engineering
18	40% Design Review
19	90% Design Review
20	**DOE Phase 2 - Construction and Start-up**
21	**Project Management**
22	Project Management - Phase 2
23	**Unit 2 Construction and Start-up**

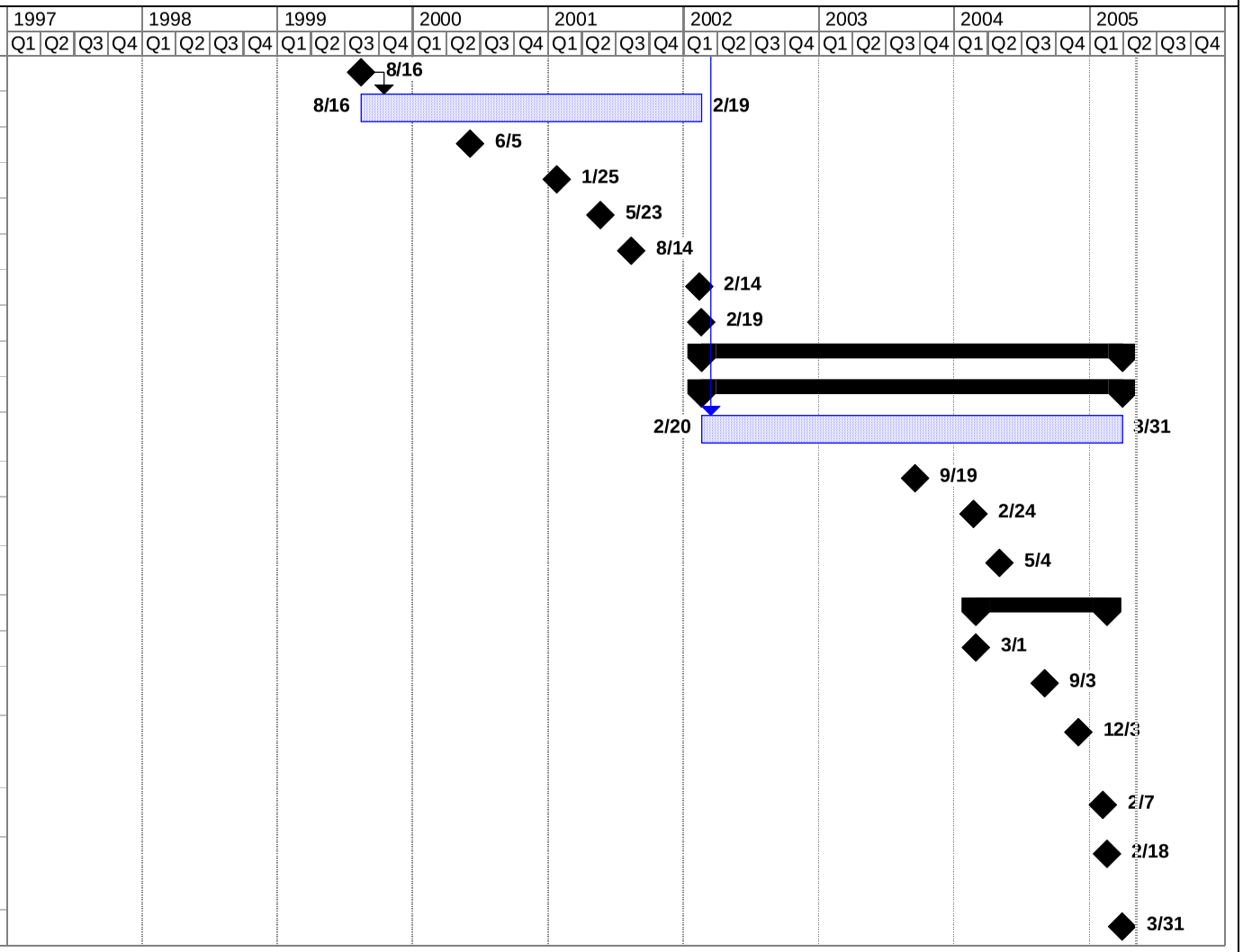


Project: NS Repowering DOE Sched
Date: Thu 5/5/05

Task		Rolled Up Task		External Tasks	
Progress		Rolled Up Milestone		Project Summary	
Milestone		Rolled Up Progress		Group By Summary	
Summary		Split			

JEA Northside Unit 2 Repowering
Summary Project Schedule

ID	Task Name
24	NTP - Boiler Construction
25	Construction Activities
26	Drum Lift
27	50% Construction Review
28	Boiler Hydro
29	100% Construction Review
30	First Fire - Solid Fuel
31	Initial Syncronization
32	**DOE Phase 3 - Operation**
33	**Project Management**
34	Project Management - Phase 3
35	Public Design Report
36	Environmental Monitoring/Test Plan
37	Start-up Modifications Report
38	**Fuel Flexibility Testing**
39	Test Protocol
40	Test Report 1 - 100% Pittsburgh 8 Coal
41	Test Report 2 - 50/50 Blend Pitt 8 Coal and Pet Coke
42	Test Report 3 - 100% Illinois 6 Coal
43	Test Report 4 - 80/20 Blend Pet Coke and Pitt 8 Coal
44	**Final Technical Report**



Project: NS Repowering DOE Sched
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Task		Rolled Up Task		External Tasks	
Progress		Rolled Up Milestone		Project Summary	
Milestone		Rolled Up Progress		Group By Summary	
Summary		Split			

3.0 PROJECT TECHNICAL OVERVIEW

The CFB boiler technology selected by JEA for the Demonstration Project is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows SO_2 capture via limestone injection, while minimizing NO_x emissions. The technology provides the capability to burn a wide range of fuels including coal, petroleum coke, and blends of the two.

Although CFB boilers are generally capable of removing over 98% of SO_2, a polishing scrubber was included to minimize reagent consumption and improve environmental performance while firing petroleum coke containing up to 8.0% sulfur. Based on the incremental amount of SO_2 removal required, dry scrubber technology, followed by a baghouse for particulate removal, was selected for the AQCS.

Firing of solid fuels on the Northside site required the design and installation of a completely new system for receiving, handling, and storing coal and petroleum coke. The same system is used for receiving and handling limestone for CFB boiler reagent.

Firing of solid fuels results in the production of ash byproducts, so new provisions had to be designed and installed for handling and processing these materials. Facilities were also included for storing the byproducts pending development of useful markets for these materials.

A detailed condition assessment of existing systems and components was conducted during the conceptual design stage of the project. Based on that report, existing systems and components were either reused, upgraded, or replaced.

Detailed System Descriptions of the major boiler, turbine, and balance of plant systems are contained in the Detailed Public Design Report for this project, which is available on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/JEAmaster.pdf

3.1 Circulating Fluidized Bed (CFB) Boilers

The need to improve the fluidized bed combustion efficiency (which also increases overall boiler efficiency and reduces operating costs) and the desire to burn a much wider range of fuels has led to the development and application of the CFB boiler. Through the years, boiler suppliers have been increasing the size of these high-efficiency steam generators. See Fig. 3-1 for the Northside CFB Process Layout.

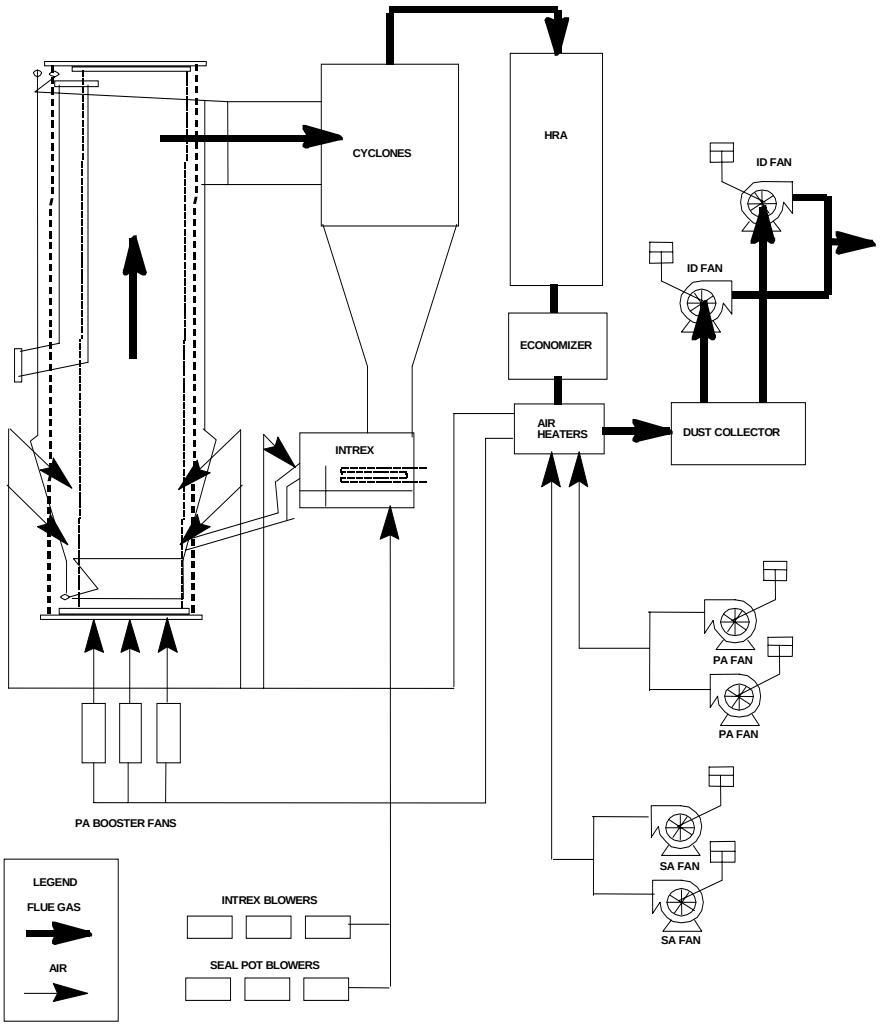


FIGURE 3-1 NORTHSIDE CFB PROCESS LAYOUT

HRA = Heat Recovery Area ID = Induced Draft
PA = Primary Air SA = Secondary Air

The CFB process offers the means for efficiently burning a wide variety of fuels while maintaining low emissions. Fuel is fed to the lower furnace where it is burned in an upward flow of combustion air. Fuel, ash, and unburned fuel carried out of the furnace are collected by a separator and returned to the lower furnace. Limestone, which is used as a sulfur sorbent, is also fed to the lower furnace. Furnace temperature is maintained in the range of 1500° to 1700° F by suitable heat absorbing surface. This process offers the following advantages:

Fuel Flexibility – The relatively low furnace temperatures are below the ash softening temperature for nearly all fuels. As a result, the furnace design is independent of ash characteristics, which allows a given furnace to handle a wide range of fuels.

Low SO_2 Emissions – Limestone is an effective sulfur sorbent in the temperature range of 1500° to 1700° F. SO_2 removal efficiency of 95% and higher has been demonstrated in the industry along with good sorbent utilization.

Low NO_X Emissions – Low furnace temperatures of 1500° to 1700° F plus staging of air feed to the furnace produces very low NO_X emissions.

High Combustion Efficiency – The long solids residence time in the furnace resulting from the collection/recirculation of solids via the cyclone, plus the vigorous solids/gas contact in the furnace caused by the fluidization airflow, results in high combustion efficiency, even with difficult-to-burn fuels. The unburned carbon loss component of the combustion efficiency is typically in the 1% to 2% range. For the JEA Northside boilers, the predicted unburned carbon loss was 2% on coal and 1.25% on petroleum coke.

3.2 Northside CFB Boilers Design Parameters

The design parameters at maximum continuous rating (MCR) for the Northside CFB Boilers are indicated in Table 3-1.

TABLE 3-1 BOILER DESIGN PARAMETERS

Parameter	100% MCR
Main Steam Flow	1,994,000 lb/hr
Main Steam Pressure at Superheater Outlet Header	2620 psig
Main Steam Pressure at Turbine	2,500 psig
Main Steam Temperature	1006° F
Reheat Steam Flow	1,773,000 lb/hr
Reheat Steam Pressure	555 psig
Reheat Steam Temperature	1006° F
Boiler Efficiency firing Performance Coal	88.1%
Boiler Efficiency firing Performance Petroleum Coke	90%

The performance fuel specifications for coal and petroleum coke, including ranges, are indicated in the following Table 3-2.

Boiler Arrangement Drawings are included in Appendix A.

TABLE 3-2 FUEL SPECIFICATIONS

Delayed Petroleum Coke				Performance Range	
	Minimum	Maximum	Performance	Minimum	Maximum
Heat Content, Btu/lb (HHV)	13,000	na	14,000	13,900	na
Hardgrove Grindability	25	80	wr	wr	wr
As received Particle Size (inches)	0	4	na	na	na
Proximate Analysis					
Volatile Matter	7.0	14.0	9.0	7.0	11.0
Fixed Carbon	71.0	88.0	81.6	na	na
Moisture	na	15.0 (Note 7)	9.0	na	15.0
Ash	na	3.0	0.4	na	3.0
Ultimate Analysis					
Carbon	78.0	89.0	79.0	79.0	85.0
Hydrogen	3.2	5.8	3.6	3.25	4.17
Nitrogen	0.4	2.0	1.0	.73	1.6
Oxygen	0.1	1.8	0.3	0.3	1.65
Sulfur	3.0	8.0	6.7	4.0	8.0
Moisture	na	15.0 (Note 7)	9.0	na	15.0
Ash	na	3.0	0.4	na	3.0
Vanadium, ppm	na	3,500 (Note 8)	na	na	na
Nickel, ppm	na	600 (Note 8)	na	na	na
Fluoride	na	(Note 5)	na	na	na
Lead	na	(Note 5)	na	na	na
Mercury	na	(Note 5)	na	na	na
Chlorine	na	(Note 10)	na	na	na
Alkalis	na	(Note 9)	na	na	na
Coal	Performance			Performance Range	
	(Note 11)			Minimum	Maximum
Heat Content, Btu/lb (HHV)	12,690			11,600	13,959
Hardgrove Grindability	na			na	na
As received Particle Size (inches)	na			na	na
Ash Fusion (reducing, soft, °F)	na			na	na
Volatile Matter (% DAF)	43.41			39.1	47.0
Proximate Analysis					
Volatile Matter	35.63			na	(Note 4)
Fixed Carbon	46.4			na	na
Moisture	5.2 (Note 8)			na	12.0
Ash (Note 3)	12.8			7.0	15.0

Coal (continued)	Performance			Performance Range	
	(Note 11)			Minimum	Maximum
Ultimate Analysis					
Carbon	68.6			66.6	70.6
Hydrogen	4.6			4.0	5.2
Nitrogen	1.3			0.8	1.6
Oxygen	4.11			3.98	4.2
Chlorine	0.09			na	0.1
Sulfur (Note 3)	3.3			2.97	3.6
Moisture	5.2 (Note 7)			na	12.0
Ash (Note 3)	12.8			7.0	15.0
Fluoride	na			na	na
Lead	na			na	na
Mercury	na			na	na
Mineral Analysis of Coal Ash					
Phosphorous Pentoxide	wr			wr	wr
Silicon Oxide	wr			wr	wr
Ferric Oxide	wr			wr	wr
Aluminum Oxide	wr			wr	wr
Titanium Oxide	wr			wr	wr
Calcium Oxide	wr			wr	wr
Magnesium Oxide	wr			wr	wr
Sulfur Trioxide	wr			wr	wr
Potassium Oxide	wr			wr	wr
Sodium Oxide	wr			wr	wr

Coal	85% MCR Range			100% MCR Range	
	Minimum	Maximum		Minimum	Maximum
Heat Content, Btu/lb (HHV)	10,000	na		11,600	na
Hardgrove Grindability	35	80		35	80
As received Particle Size (inches)	0	4		0	4
Ash Fusion (reducing, soft, °F)	2,050	2,680		2,050	2,680
Volatile Matter (% DAF)	na	47.0		na	47.0
Proximate Analysis					
Volatile Matter	20.0	40.0 (Note 4)		30	36
Fixed Carbon	37.0	na		42	na
Moisture	na	15.0 (Note 7)		Na	13.0 (Note 7)
Ash (Note 3)	7.0	15.0		7.0	15.0
Ultimate Analysis					
Carbon	49.3	86.0		59	72
Hydrogen	3.2	6.0		3.9	5.3
Nitrogen	0.4	1.9		0.8	1.6

Coal (continued)	85% MCR Range			100% MCR Range	
	Minimum	Maximum		Minimum	Maximum
Oxygen	3.0	9.8		3.0	9.8
Chlorine	na	0.3 (Note 10)		na	0.3 (Note 10)
Sulfur (Note 3)	0.5	4.5		0.5	4.5
Moisture	na	15.0 (Note 7)		na	13.0 (Note 7)
Ash (Note 3)	7.0	15.0		7.0	15.0
Fluoride	na	(Note 5)		na	(Note 5)
Lead	na	(Note 5)		na	(Note 5)
Mercury	na	(Note 5)		na	(Note 5)
Mineral Analysis of Coal Ash					
Phosphorous Pentoxide	0.04	3.0		0.04	3.0
Silicon Oxide	30.0	65.0		30.0	65.0
Ferric Oxide	2.9	45.0		2.9	45
Aluminum Oxide	18.0	36.0		18.0	36.0
Titanium Oxide	0.3	3.0		0.3	3.0
Calcium Oxide	0.5	9.0		0.5	9.0
Magnesium Oxide	0.1	2.0		0.1	2.0
Sulfur Trioxide	0.1	8.0		0.1	8.0
Potassium Oxide	0.1	4.0 (Note 9)		0.1	4.0 (Note 9)
Sodium Oxide	0.1	2.0 (Note 9)		0.1	2.0 (Note 9)

Note:

1. na = no limit applicable
2. All data is for fuel "as received", and is percent by weight unless otherwise noted.
3. Coal minimum sulfur content is 0.5% given at least 12.0% ash. Coal minimum ash content is 7.0%, given at least 1.0% sulfur. For coals with sulfur content between 0.5% and 1.0%, and ash content between 7% and 12%, the minimum coal ash content as a function of sulfur content shall be as shown in Fig. 3-5.
4. The maximum coal volatile matter is 47% on a dry-ash free basis.
5. The emissions guarantee shall be based upon uncontrolled emissions as resulting from the combined inputs from fuel and limestone that do not exceed the following values:
   Lead - 0.00278 lb/MBtu (HHV)
   Mercury - 0.0000174 lb/MBtu (HHV)
   Fluorine (as HF) - 0.0106 lb/MBtu (HHV)
6. wr = within range
7. Surface moisture of the crushed fuel should be below 10% to avoid conveying and feeding hang-ups.
8. The total vanadium and nickel content in the fuel should not exceed 2,000 ppm. Operation at higher levels than 2,000 ppm will result in increased outages for unit cleaning and repairs.
9. The fuels fired in the boiler should have a combined acetic acid soluble sodium (Na) and potassium (K) content less than 0.05% (500 ppm) on a dry fuel basis to prevent bed sintering and agglomeration.
10. The chlorine level in the fuel should be less than 0.1% on a dry fuel basis to avoid corrosion and agglomeration problems.
11. Performance coal will be Eastern US coal.

3.3 Limestone Preparation System

The limestone preparation system grinds and dries raw limestone and pneumatically transports it to the limestone storage silo for each unit. The limestone preparation system is designed for grinding limestone at a maximum feed size of 1 inch to a product size of -2000 microns meeting the CFB desired product distribution curve, with a residual moisture content of 1% maximum.

Three pneumatic transfer systems, one for each unit, and a shared spare system, are provided to convey the prepared limestone from the preparation building to the unit's silo. Each system is capable of transferring limestone to either Unit 1 or 2.

3.4 Air Quality Control System (AQCS)

To optimize overall plant performance, a polishing SO_2 scrubber was included in the design. The CFB boiler provides approximately 90% SO_2 capture via limestone injection, with the remaining capture from a semi-dry polishing scrubber via injection of lime. Overall SO_2 capture is over 98%.

Although CFB boilers can achieve 98% SO_2 removal, limestone utilization is reduced as removal efficiencies exceed 90% to 95%. The polishing scrubber allows reduction of the overall sorbent use, such that the savings in operating cost (sorbent, ash disposal) offset the capital and operating costs of the polishing scrubber. Another consideration in the decision to add the scrubber was the enhanced environmental performance regarding reductions of trace element emissions provided by the scrubber.

The polishing scrubber is a spray dryer/baghouse combination. The spray dryer utilizes a dual fluid nozzle atomized with air, and the baghouse is a pulse-jet design. A key feature of the polishing scrubber is a recycle system which adds fly ash to the reagent feed, thus utilizing the unreacted lime in the fly ash from the CFB boiler and reducing the amount of fresh lime required.

The polishing scrubber for each unit, provided by Wheelabrator Air Pollution Control (WAPC), consists of a Spray Dryer Absorber/Fabric Filter (SDA/FF) Dry Scrubbing System to control SO_2 and acid gases, solid particulates, and heavy metals. Each system consists of:

- A Two Fluid Nozzle Spray Dryer Absorber (SDA)
- A Medium-Pressure Pulse Jet Fabric Filter (FF)
- A Feed Slurry Preparation System
- A common Absorbent Preparation System for both units, consisting of a Lime Storage Silo, redundant Vertical Ball Mill Slaking Systems, and redundant Transfer/Storage Tanks and pumps.
- A common Air Compressor System to provide atomizing air for the SDA, dried pulse air for the FF, and instrument air. The compressors are provided with a closed loop cooling system. Waste heat from the compressor is used to preheat the reuse water feed to the SDA Feed Slurry System.

3.5 Turbine Generator and Balance of Plant Systems

The Unit 2 Turbine Generator (TG) was upgraded to maximize output and improve turbine heat rate as much as practical. The high pressure/intermediate pressure (HP/IP) rotor, diaphragms, and inner casing

were replaced with a General Electric (GE) Dense Pack design, which added four stages to the turbine, and increased turbine efficiency. The normal operating throttle pressure was also increased from 2400 psig to 2500 psig. In addition, the original mechanical linkage type turbine control system was replaced with a state-of-the-art Mark VI electrohydraulic control system, to allow better response to load changes and for complete integrated control, protection, and monitoring of the turbine generator and accessories. A new brushless excitation system was also installed on the generator, and a new turbine lube-oil conditioner was installed.

Unit 2 was originally designed to provide power to the JEA grid at 138kV. However, to better interface with present and future grid capabilities, the output from Unit 2 was increased to 230 kV. This required replacement of the generator step-up transformer and associated substation upgrades.

The once-through circulating water system was upgraded by replacing the original 90% copper/10% nickel heat-transfer surfaces in the condenser damaged by erosion/corrosion with modular bundles consisting of titanium tubes welded to solid titanium tubesheets. The existing circulating water pumps were replaced with larger capacity pumps. The traveling screens were replaced with those that have man-made basket material to increase their life. Debris filters were added to minimize condenser tube pluggage and possible damage. A sodium hypochlorite shock-treatment system was installed to prevent sea life from adhering to the titanium components of the condenser.

Upgrades to the condensate system in Unit 2 included upgrades to the condensate pumps and condensate booster pumps, replacement of the steam packing exhausters, replacement of the low pressure (LP) feedwater heaters, including replacement of the tube bundle in the lowest pressure heater (located in the condenser neck), replacement of the deaerator and storage tank, installation of a new condensate polisher, and installation of new chemical feed systems. The new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

Upgrades to the feedwater system in Unit 2 included replacement of the HP feedwater heaters, upgrades to the boiler feed pumps and fluid drives, and replacement of the boiler feed pump drive motor. Again, the new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

The capability of existing piping systems and components in Unit 2 was reviewed to confirm adequacy for the new operating and design conditions. If necessary, these systems and components were upgraded or replaced. Existing 2-½ inch and larger valves in Unit 2 were either refurbished or replaced. Nearly all 2 inch and smaller piping and valves in Unit 2 were replaced. Essentially all instrumentation in Unit 2 was replaced.

The original control systems in Unit 2 were replaced with a new distributed control system (DCS) provided by ABB Inc, to provide control, monitoring, and protection of the boiler, turbine interfaces, and balance of plant systems. FW provided the logic design for the CFB boiler, and B&V provided the logic design for the BOP systems, including provisions for turbine water induction prevention (TWIP). ABB provided the programming to implement the logic design for the boiler and BOP systems.

The Unit 2 auxiliary electric system (switchgear and motor control centers) was replaced because of equipment obsolescence. All power and control wiring was replaced due to the age of the wiring and because the existing control wiring was not segregated from the power wiring, thus not meeting the

requirements of the new DCS system.

Other miscellaneous enhancements included the installation of additional air dryers and screw-type air compressors and the installation of titanium plate-type heat exchangers for the Unit 2 closed cooling water system, similar to those previously installed in Unit 1.

3.6 Fuel Handling System (Coal, Petroleum Coke, and Limestone)

The function of the Fuel Handling System is to receive coal, petroleum coke, and limestone from "Panamax" vessels (maximum vessel size which can pass through the Panama Canal) and to convey it to stock-out and storage areas. From there coal and petroleum coke are reclaimed and conveyed to the in-plant fuel silos; limestone is reclaimed and conveyed to the Limestone Preparation System.

The major components of the Fuel Handling System are as follows:

- Continuous Ship Unloader
- Belt Conveyors and Support Structures
- Domes
- Radial Stacker/Reclaimers
- Traveling Trippers
- Belt Feeders
- Belt Scales
- Magnetic Separators
- Metal Detectors
- Gates and Chutework
- Dust Suppression and Dust Collection Systems
- Screw Conveyors
- Vacuum Cleaning Systems
- Hoppers
- Telescopic Chute

3.7 Ash Handling

The ash handling system transports bed ash from the outlets of the stripper coolers to the bed ash silos. It also transports fly ash from the economizer and air heater hoppers, as well as the baghouse hoppers, to the fly ash silos. Two sets of ash handling systems and associated equipment are provided, one for Unit 1 and the other for Unit 2.

3.8 Reuse Water

Reuse water is domestic wastewater that has been treated and disinfected to a high degree and is reused for beneficial purposes. The reuse water used at NGS is treated wastewater from the District II Water Reclamation Facility. The wastewater is treated through primary, secondary and advanced treatment. During primary treatment, large solids are removed from the wastewater. Secondary treatment uses microorganisms to remove the remaining solids and organic material from the wastewater. After secondary treatment, the wastewater travels through cloth membrane filters, with a pore size of approximately 10 microns, to remove virtually all remaining solids. During advanced or final treatment, the wastewater is disinfected using chlorine or ultraviolet light to destroy bacteria, viruses and

other pathogens.

Consumption of reuse water at NGS is nearly 1 million gallons per day when all three units are operating. The reuse water is used for circulating water pump seals, boiler/precipitation area drains, polishing scrubbers, ash slurry preparation, and fuel handling dust suppression and wash down. Future uses may include irrigation.

3.9 Ash Processing and Storage

Two bed ash silos and two fly ash silos provide for short term (approximately three days) surge capacity and storage of bed ash and fly ash. The bed ash and fly ash from the silos is slurried using reuse water. The bed ash slurry and fly ash slurry are then blended together and pumped to the Byproduct Storage Area (BSA) using positive displacement GEHO pumps.

Ash in the BSA sets up to form a low strength aggregate type material, with essentially the only water run-off being precipitation which falls in the area. This aggregate material is suitable for use as fill material for road construction or other applications where fill material is needed. JEA has received an approval letter from FDEP characterizing their CFB byproduct (bed ash and fly ash) as an "industrial byproduct" and allowing it to be used for beneficial purposes such as civil applications and stabilization processes for remedial projects. JEA is actively marketing and selling this material in Florida and Georgia, with the intent of transporting all ash generated to off site locations for beneficial uses.

4.0 START-UP

FW was responsible for the commissioning and start-up of the boiler and AQCS systems, and ZCC was responsible for the commissioning and start-up of BOP systems. The JEA Start-up Group was responsible for the overall coordination of plant start-up, as well as commissioning and start-up of the Material Handling Systems (coal, petroleum coke, and limestone), and of the turbine/generator and related auxiliary systems. JEA Operations was responsible for operation of completed and integrated systems after turnover of the various systems for normal operation.

Detailed design activities for the project were essentially complete by July 2001. FW began on-site staffing for the commissioning and start-up activities for the FW scope of work for the project in the latter part of 2000. Pre-boiler chemical cleaning of the Unit 2 condensate and feedwater systems (excluding boiler systems) was completed in early June 2001. Chemical cleaning of the Unit 2 boiler was completed in September 2001. First fire of Unit 2 on gas occurred on December 1, 2001, and Unit 2 steam blows were completed on January 15, 2002. Initial synchronization of Unit 2 occurred on February 19, 2002, and full load operation (on coal) was achieved and sustained on May 5, 2002.

4.1 Modifications During Start-up and Initial Operation

As indicated above, the detailed design activities for the project were essentially complete by July 2001, but some design changes and scope additions were made during the latter stages of construction and start-up. Many of these changes were issued due to scope increases or changes requested by JEA, field conditions that differed from the design basis (due to missing or incorrect vendor data, incorrect field data, etc), drawing errors, etc. Other changes were identified and implemented during start-up and initial operation of various integrated systems and initial operation of Unit 2 by JEA.

After August 2002, JEA initiated a number of modifications and changes that could be implemented quickly, with little or no down time, to improve the operation of the Unit 2 boiler and AQCS systems. Many of these modifications were implemented during the Fall 2002 planned outage. In addition, JEA developed a more comprehensive list of design modifications and changes which could be completed during a scheduled outage in the Spring of 2003, to optimize performance of Unit 2 during the summer peak period. These modifications are referred to as Phase I Completion Modifications.

A detailed description of the Unit 2 Start-up, and of the modifications made during start-up and initial operation, can be found in the Start-up Modifications Report for this project, which is available on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/Start-Up%20Modifications%20Report_final.pdf

5.0 OPERATIONS AND MAINTENANCE

Prior to the Repowering Project, Units 1 and 3 fired relatively high cost liquid fuels and natural gas (Unit 2 was not operating). As a result, capacity factor of these units was limited due to economic dispatching practices by JEA. Since Units 1 and Unit 2 have been repowered, they have fired relatively low cost solid fuels (Unit 3 continues to fire liquid fuels and natural gas). As a result, the combined power production of the three units has increased significantly, and at the same time, total plant emissions have been reduced.

Significant changes in operations and maintenance (O&M) practices were required by the change of Units 1 and 2 from oil and gas fired boilers to solid fueled boilers, with associated AQCS and ash handling systems. During start-up and testing of the units, JEA dedicated significant efforts and costs to development of O&M procedures and to training of O&M personnel for the new equipment and systems.

5.1 Unit 2 Operations Summary

From the time of initial synchronization on February 19, 2002, Unit 2 was in combined start-up, testing, and operational mode of service through the summer of 2002. Initial operation of the boiler on coal and higher ratios of coal/pet coke blends were successful. However, attempts at operation on 100% pet coke resulted in agglomeration of ash in the INTREX's and cyclones within a week or so of operation, requiring a forced outage to remove the ash build-up. As a result, blending of pet coke and coal was required for reliable operation of the boiler. Initially, the ratio was limited to a maximum of 70% pet coke, but this was increased to 80% pet coke after the 2002 summer peak season. Other significant problems encountered with the boiler operation included limestone drying and feed problems, stripper cooler pluggages, expansion joint failures, and back-sifting into the PA plenum. Problems were also encountered with density control and spray quality in the AQCS system. The issues with limestone feed resulted in an operational practice of overfeeding limestone to the boiler in order to preclude excursions of SO_2 emissions from the stack. This resulted in doing most of the SO_2 removal in the boiler.

A summary of key annual operating and availability data for Unit 2 for calendar year (CY) 2003 and 2004, is provided in Table 5-1.

TABLE 5-1 ANNUAL OPERATING AND AVAILABILITY DATA

Parameter	CY 2003	CY 2004	Remarks
Gross MWH's Generated	1,791,221	1,459,351	NERC: Gross Actual Generation (GAG)
Net MWH's	1,673,981	1,357,427	
Heat Rate, B/kWh	9,514	9,518	
Starts	15	9	Excludes Attempted Starts
Hours on Line	6,843	5,450	NERC: Service Hours (SH)
Load Factor (Gross)	88.0%	90.0%	NERC: Gross Output Factor (GOF)
Net Output Factor (NOF), %	87.2%	89.3%	
Capacity Factor (Gross)	68.7%	55.8%	NERC: Gross Capacity Factor (GCF)
Net Capacity Factor (NCF), %	68.2%	55.6%	
Equivalent Availability Factor (EAF)	72.8%	58.7%	

A monthly summary of Unit 2 operating data during 2003, and 2004 is provided in Appendix C.

For purposes of comparison to the Northside Unit 2 operating data above, Table 5-2 below presents the industry average operating and availability data for coal plants in the United States of capacity between 200 MW and 399 MW, based on data for calendar years 1999 through 2003, as reported in the North American Electric Reliability Council (NERC) Generating Availability Report. While the coal plants of this size in the NERC data base are primarily pulverized coal units with scrubbers, a comparison to Northside Unit 2 (also solid fuel fired with scrubbers) is considered to be indicative, but not directly comparable. It should also be noted that these statistics are from units that have been operating for many years and have worked through startup and early operational issues to achieve a stable O&M mode. This process has not yet been completed on Unit 2. One single issue with a large impact on performance is the failure of superheater tubes.

During the time frame of August 2003 through May 2004, the boiler experienced a series of outages due to superheater tube failures (see Section 5.2 below). A detailed discussion of technical issues surrounding these failures can be found in Section 6.1. This single issue resulted in a loss of about 464,100 MWh's of generation during CY 2003 and 2004. If these tube failures had not occurred, the average EAF during CY 2003 and 2004 would have been nearly 75%, as indicated in the Table 5-2.

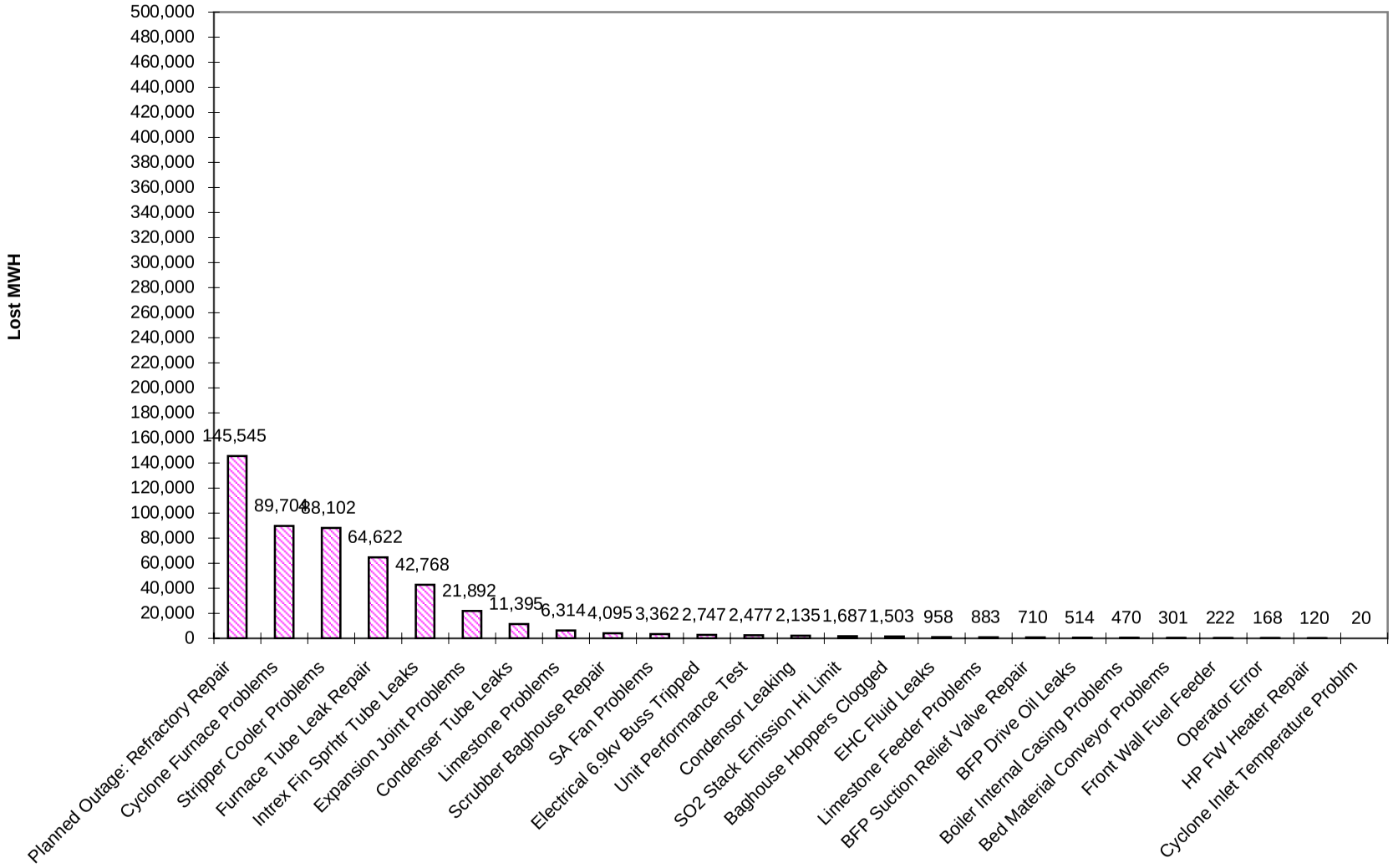
TABLE 5-2 COMPARISONS TO NERC DATA

Parameter	200 to 399 MW Unit Size (1)	NS Unit 2 Averages for CY 2003 and 2004	Northside Unit 2 Averages without SH Tube Failures CY 2003 and 2004
Average Dependable Capacity (Gross), MW	299.5	297.5	297.5
Average Actual Unit Starts per Year	14.73	12	10 (estimated)
Average Service Hours per Year	7,434	6,146.5	
Average Service Factor, SF, %	84.85	78.2	
Average Net Output Factor, NOF, %	81.21	88.3	
Average EAF, %	84.01	65.8	74.7
1. Based on North American Electric Reliability Council, Generating Availability Data System, for coal fired steam units, 1999 thru 2003.			

A graphical representation of Unit 2 lost generation hours during 2003 and 2004 by NERC cause code is provided on the following pages.

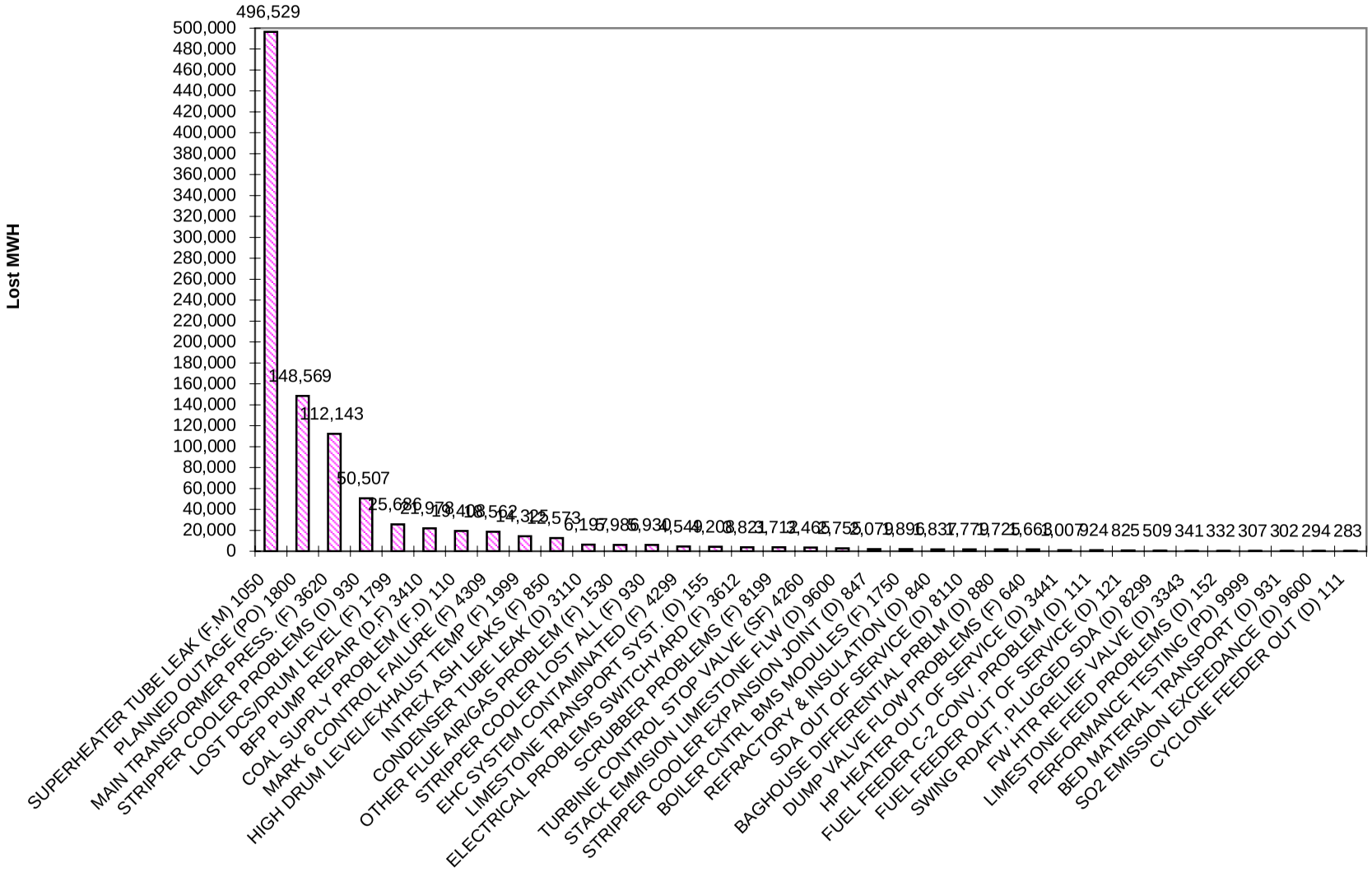
NS2 Lost MWH by Cause for FY03

(GADS Data)



NS2 Lost MWH by Cause for FY04

(GADS Data)



5.1.1 Water and Wastewater Flows. A water mass balance diagram for the Northside Plant site (Units 1, 2, and 3) is included in Appendix A. A summary of actual average daily flows for some of the key flow streams, based on available monthly flow data for CY 2003, and 2004, is shown in Table 5-3. Applicable permit limits are also indicated.

TABLE 5-3 AVERAGE DAILY WATER FLOWS

	Average Daily Flow, Gallons per Day (GPD) X 1000				
Flow Stream	**Water Balance***		**CY 2003**	**CY 2004**	**Permit Limit**
Surface Water	827,000 (827,000)		782,173	763,770	827,000
Ground Water	517.6 (1,283.7)		530.4	590.9	571.0
Reuse Water	853.9 (2,299.6)		809.6**	991.9**	928.8
CWTS Influent	431.6 (1,744.7)		497.8	601.3	
Perc Ponds to District II	0.0 (250.0)		126.8	132.1	
	* Flows in parenthesis are 24 hour maximum flows.				
	** Excludes December 2003 through April 2004 due to broken reuse water pipeline.				

Monthly water and wastewater flow rates for the Northside site are indicated with the operating data in Appendix C.

5.1.2 Stack Emissions. Stack emissions data for Unit 2 is collected and reported by the Continuous Emissions Monitoring System (CEMS). Table 5-4 below provides a summary of Unit 2 stack emissions data during 2003 and 2004.

TABLE 5-4 STACK EMISSIONS DATA

Parameter	CY 2003	CY 2004	Permit Limits
SO2 Emissions, Tons	1,131.8	1,095.6	
SO2 Emissions, lb/MMBtu	0.14	0.17	0.20 (24 hr average)
NOx Emissions, Tons	525.5	492.6	
NOx Emissions, lb/MMbtu	0.07	0.08	0.09 (30 day average)
Particulate Matter, Tons	41.23	29.72	
Particulate Matter, lb/MMbtu	0.005	0.005	
CO, Tons	297.3	290.6	
CO, lb/MMbtu	0.04	0.04	
CO, lb/hr	84	100	350 (24 hr average)
VOC, Tons	11.92	11.63	
VOC, lb/MMbtu	0.001	0.002	
VOC, lb/hr	3.4	4.0	

Monthly stack emissions data for Unit 2 is included with the operating data in Appendix C.

5.1.3 Ash Production. Total bed ash and fly ash production rates for Units 1 and 2 combined are as follows, along with an estimate of the portion of the bed ash and fly ash from Unit 2.

TABLE 5-5 ASH PRODUCTION RATES

Parameter	CY 2003	CY 2004
Total Bed Ash, Tons	312,400	195,439
Total Fly Ash, Tons	179,700	153,623
Unit 2 Bed Ash, Tons	153,236	96,515
Unit 2 Fly Ash, Tons	88,145	75,865
Byproduct Sales	0	38,312

Note that some byproduct sales were made in 2004, primarily into Georgia. In late 2004, JEA received an approval letter from FDEP characterizing their CFB byproduct (bed ash and fly ash) as an "industrial byproduct" and allowing it to be used for beneficial purposes such as civil applications and stabilization processes for remedial projects. All byproduct generated is expected to be sold, and the originally planned Cell 2 of the BSA is not being developed.

5.2 Unit 2 Maintenance Summary

The level of maintenance required on Unit 2, particularly the boiler, has been relatively high, due to the ash agglomeration problems, limestone feed problems, stripper cooler pluggages, expansion joint failures, and back-sifting into the PA plenum mentioned above. Table 5-6 provides a list of Unit 2 outages of significant duration, through December 2004, which have been required to address many of these problems.

TABLE 5-6 MAJOR UNIT 2 OUTAGES

Outage Start Date	Outage End Date	Duration, Days	Primary Purpose of Outage
April 16, 2002	April 30, 2002	14	MFT, Removal of excessive ash build-up
May 31, 2002	June 14, 2002	14	Tube Leak Repairs
July 7, 2002	July 19, 2002	12	Bed Excursion in Boiler
July 27, 2002	August 9, 2002	12	Remove Pluggage in Cyclone
October 22, 2002	November 17, 2002	26	Planned Outage for Boiler Modifications
December 21, 2002	January 8, 2003	19	Stripper Cooler Problems
January 28, 2003	February 6, 2003	9	Furnace Wall Tube Repairs
April 1, 2003	April 23, 2003	21	Planned Outage for Boiler Refractory Modifications and Repairs
August 19, 2003	September 8, 2003	20	Cyclone problems, Intrex tube leaks

Outage Start Date	Outage End Date	Duration, Days	Primary Purpose of Outage
November 3, 2003	November 25, 2003	22	Boiler Inspection
February 11, 2004	March 4, 2004	22	Superheater Tube Leaks (Intrex)
March 8, 2004	March 19, 2004	11	Superheater Tube Leaks (Intrex)
March 30, 2004	April 5, 2004	6	Superheater Tube Leaks (Intrex)
May 1, 2004	May 7, 2004	6	Superheater Tube Leaks (Intrex)
June 19, 2004	July 6, 2004	17	Change-out of Generator Step-up Transformer
October 26, 2004	November 29, 2004	32	Planned Outage for Boiler Modifications

In addition, there were numerous other load reductions and short unit outages in the above time frame. Note that the monthly Equivalent Availability Factors (EAF's) for 2003 and 2004 listed in the Operating Data in Appendix C include all unit outages and load reductions.

5.3 O&M Staffing

O&M of the three units at the Northside site is handled by a single organization within JEA, which in many cases shares or rotates duties and responsibilities between units. The total O&M staff presently consists of a total of 251 persons for the three units. Units 1 and 2 are each a nominal 300 MW CFB pet coke/coal fired unit, and Unit 3 is a 530 MW heavy oil fired unit.

5.4 O&M Costs

During the first two years of operation, Unit 2 encountered significant operating problems (primarily boiler related) and associated forced outages which resulted in high maintenance and repair costs and a low EAF, as described above. As a result, the annual O&M costs for Unit 2, particularly on a per MWh basis, were extremely high during the demonstration period, and are not considered to be representative of future O&M costs for the unit. Refer to Section 6.0 for a description of boiler design modifications and upgrades that have been, or are being, implemented to improve boiler reliability and operation.

6.0 MODIFICATIONS AND UPGRADES (PHASE II)

In addition to the Phase I Completion Modifications made during the Spring 2003 outage on Unit 2, JEA has also implemented, or is considering implementing, a number of additional major modifications, referred to as Phase II completion modifications. The intent of these modifications is to further improve the reliability, maintainability, and performance of Unit 2. These modifications include the following:

- Intrex Design Modifications
- Expansion Joint Modifications
- Stripper Cooler Modifications
- Limestone Silo and Feed System Modifications
- Limestone Preparation System Modifications

The following paragraphs provide a description of the problems encountered and the modifications being considered to resolve these problems.

6.1 Intrex Design Modifications

The intrex is the part of the boiler that contains both the loop seal and the intermediate and finishing superheater surface. The boiler has three intrex boxes, two with intermediate superheat surface and one with finishing superheat surface. There are both mechanical and operational issues with the design of the intrex. The mechanical issues consist of superheater tube support failure and in-service cracking of superheater tubes. The operational issues consist of agglomeration of the hot loop material within the intrex and backing up of material into the cyclone.

The superheater tube failures are attributed to a combination of the design of the tube bundle support system coupled with lack of solution annealing of the tube bends. The primary failure is radial cracking of the superheater tube bend at the weld. The problem is found to be the worst in the finishing superheater where the steam temperatures are the highest, and is most prevalent on the bend where the large bundle support lug is installed. The large lug acted as a heat exchange fin and caused the operating temperature of the particular tube bend to be higher than the rest of the bundle, which accelerated the failure.

An investigation revealed that at the time of design ASME code did not require solution annealing of the bends for the stresses that were calculated to exist in the bundle. Following the manufacture of these elements the code was changed, and if manufactured today the tube bends would have to be solution annealed.

As a temporary measure all of the finishing superheater bends were replaced with solution annealed bends without the large support lug. The support system was re-designed to include only a sliding pad. At the same time the temporary repair was being performed a design was done and material was ordered to install replacement finishing superheater tube bundles. The design called for 50% of the surface area to be replaced, with the balance being eliminated due to installation considerations. The replacement

bundles were installed in the fall 04 planned outages and have provided satisfactory performance.

The operational issues with the intrex boxes include agglomeration of hot loop material within the boxes while burning high percentages of petroleum coke. This has resulted in pluggage of the boiler cyclone with agglomerated hot loop material. The failure mechanism appears to be agglomeration of the material under conditions of poor fluidization. To mitigate the problem without major modifications it is necessary to burn at least 20% coal with the petroleum coke to reduce the tendency of the hot loop material to agglomerate.

JEA is currently evaluating long-term modifications that will mitigate both the agglomeration and tube failure issues. These modifications are expected to be implemented within the next five years.

6.2 Expansion Joint Modifications

JEA has experienced failures of the hot loop expansion joints, including the cyclone inlet, cyclone outlet and intrex return leg expansion joints. Minor design modifications have been successfully performed to reduce forced outages due to these expansion joints. It is expected that further modifications will be performed associated with the intrex modifications noted above.

6.3 Stripper Cooler Modifications

Bed ash is removed from the boiler through stripper coolers which are designed to remove carbon from the ash and cool the ash. JEA has experienced both mechanical and operational issues with the stripper coolers. The stripper coolers are mounted to the boiler steel and close-coupled to the boiler through a sliding expansion joint. There have been numerous failures and high O&M cost associated with these expansion joints. Modifications have been performed to reduce the forced outages and derates associated with these joints, but further improvements are desired. Operationally, the coolers are not able to operate at design capacity and forced derates sometimes occur due to pluggage or inadequate flow. A considerable amount of O&M is spent attempting to unplug or restart flow through stripper coolers. JEA is currently evaluating a range of changes from modification of the existing coolers all the way through replacement with an alternate design.

6.4 Limestone Silo and Feed System Modifications

The original limestone feed system from the bottom of the limestone silos near the boilers for Northside Units 1 and 2 were prone to “rat-holing” and/or bridging, interrupting the flow of limestone to the boilers. Frequent manual rodding of the limestone in the silo and lower hoppers was required to restore the flow of limestone, particularly when the limestone moisture content was high. To eliminate the limestone feed interruptions, Jenike & Johanson (J&J), a company specializing in the design on bulk material handling systems, designed and furnished system modifications to replace the lower conical portion of each limestone silo with a mass flow hopper bottom. In addition, the rotary feed type valves were replaced with hopper outlet slide gate valves, mass flow screw feeders, diverter valves and stainless steel pipe chutes to the inlets of existing rotary air lock valves. On-site construction work was performed by one of the JEA Alliance Contractors during the Fall 2004 outages on Units 1 and 2. Although limestone feed issues have not been eliminated, performance has improved significantly. It is believed that most remaining issues are related to moisture in the finished limestone.

6.5 Limestone Preparation System Modifications

The limestone preparation system that was supplied was not able to meet the design drying capacity or the design sizing curve. An ongoing program is underway to improve limestone drying and reduce the amount of fines produced by the preparation process. Improvements have been made, and JEA is continuing to perform tests to optimize the process. The final resolution is not yet known.

7.0 PERFORMANCE TESTING

7.1 INTRODUCTION

The Cooperative Agreement between the DOE and JEA required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels, specifically Pittsburgh 8 coal, Illinois 6 coal, and two blends of Pittsburgh 8 coal with petroleum coke. Therefore, four fuel flexibility demonstration tests were conducted during 2004 to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility was quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin
    - Furan
- Stack opacity

Note that the term “unit” refers to the combination of the CFB boiler and the AQCS. The AQCS consists of a lime-based SDA and a PJFF

7.2 Test Protocol

The tests were conducted in accordance with an approved Fuel Capability Demonstration Test Protocol, which can be accessed on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

7.3 Test Schedule

The four fuel capability demonstration tests were conducted on the following dates:

• Test 1	100% Pittsburgh 8 coal	January 13 through 16, 2004
• Test 2	50/50 Blend Pitt 8 Coal and Pet Coke	January 27 through 31, 2004
• Test 3	Illinois 6 Coal	June 7 through 9, 2004
• Test 4	80/20 Blend Pet Coke and Pitt 8 Coal	August 10 through 13, 2004

7.4 Summary of Test Results

7.4.1 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the 'closed' position of certain main steam and feedwater system valves.

7.4.2 Test Reports

A detailed test report was prepared to document the results of each test. Each report includes commentary on the test results as well as limited part load performance data. These detailed reports can be accessed on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/library/bibliography/demonstration/aepg/baepgfb_jackea.html

7.4.3 Full Load Test Results

The results of the 100% load tests are summarized in Tables 7-1 through 7-4 on the following pages. The design MCR values indicated are the original design values provided by FW. Corrections to MCR conditions were made in accordance with Section 6.2.1 of the Fuel Capability Demonstration Test Protocol.

TABLE 7-1 - 100% PITTBURGH 8 FUEL TESTS RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	January 13, 2004 Test (**corrected to MCR, see Note 4)	January 14, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1	90.6** (Note 1)	90.6** (Note 1)
Capacity Calculation (percent)	NA	97.14	94.55
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,999,572**	2,000,369**
Pressure (psig)	2,500	2,400	2400
Temperature (°F)	1,000	997**	996.6**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,820,447	1,769,377
Pressure (psig)	547.7	570.9	568.7
Temperature (°F)	1,000	1008.1**	1008.25**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,819,973	1,768,905
Pressure (psig)	608.6	570.5	568.24
Enthalpy (Btu/lb)	1,304.5	1297.3	1,297.3
Feedwater to Economizer			
Temperature (°F)	487.5	484.5	484.1
Pittsburgh 8 Coal Constituents (As-Received)			
Carbon %	68.6	72.7	72.3
Hydrogen %	4.6	4.84	4.7
Sulfur %	3.3	4.84	4.56
Nitrogen %	1.3	1.37	1.35
Chlorine %	0.09	0.18	0.14
Oxygen %	4.11	2.11	2.54
Ash %	12.8	6.89	7.06
Moisture %	5.2	7.26	7.39
HHV (Btu/lb)	12,690	12,877	12,970
Fuel Flow Rate (lb/hr)	NA	207,558	206,906
Limestone Composition (% By Weight)			
CaCO3	92.0	90.86	91.81
MgCO3	3.0	3.31	2.95
Inerts	4.0	5.34	4.9
Total Moisture	1.0	0.49	0.34

Parameter	**Design Maximum-Continuous Rating (MCR)**	**January 13, 2004 Test (**corrected to MCR, see Note 4)**	**January 14, 2004 Test (**corrected to MCR, see Note 4)**
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	45.15	46.02
MgO and inerts	15.0	54.85	53.98
AQCS Lime Slurry Density – % Solids	35	5.57	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	57,600	54,625
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.074	0.081
Uncontrolled SO_2, lb/MMBtu (HHV)	5.20	7.52	7.03
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2371	.2902
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.102	0.106
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.004	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.026	0.027
Opacity, percent	10	1.1	1.0
Ammonia (NH_3) Slip, ppmvd	2.0	1.17	
Ammonia feed rate, gal/hr	NA	7.16	8.38
Lead, lb/MMBtu	2.60×10^{-5} (max)	3.516×10^{-7}	
Mercury (fuel and limestone)	NA	8.24×10^{-6}	
Mercury, lb/MMBtu (at stack)	1.05×10^{-5} (max)	7.238×10^{-6} (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	14.0	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 3.09 \times 10^{-5}$	
Dioxins / Furans	No Limit	6.52×10^{-14}	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 1 for description of mercury testing anomaly.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.

TABLE 7-2 - 50/50 BLEND PITT 8 COAL AND PET COKE TEST RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	January 27, 2004 Test (**corrected to MCR, see Note 4)	January 28, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.6 **(Note 1)	91.7 **(Note 1)
Capacity Calculation (percent)	NA	95.3	95.4
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,848,031**	1,846,341**
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	1,002**	1,001**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,776,860	1,776,167
Pressure (psig)	547.7	569.1	565.4
Temperature (°F)	1,000	1,007**	1,008**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,775,434	1,774,004
Pressure (psig)	608.6	568.4	564.9
Enthalpy (Btu/lb)	1,304.5	1,295.25	1,292.91
Feedwater to Economizer			
Temperature (°F)	487.5	484.3	483.5
50/50 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	74.45	73.68
Hydrogen %	4.1	4.4	4.6
Sulfur %	5.0	5.34	5.86
Nitrogen %	1.15	1.47	1.63
Chlorine %	0.05	0.09	0.11
Oxygen %	2.20	1.25	1.26
Ash %	6.6	5.75	5.91
Moisture %	7.1	7.34	7.05
HHV (Btu/lb)	13,345	13,429	13,251
Fuel Flow Rate (lb/hr)	NA	194,172	195,177
Limestone Composition (% By Weight)			
$CaCO_3$	92.0	91.4	86.4
$MgCO_3$	3.0	2.95	2.82
Inerts	4.0	5.15	10.43
Total Moisture	1.0	0.51	0.36

Parameter	**Design Maximum-Continuous Rating (MCR)**	**January 27, 2004 Test (**corrected to MCR, see Note 4)**	**January 28, 2004 Test (**corrected to MCR, see Note 4)**
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	46.77	47.03
MgO and inerts	15.0	53.23	52.97
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	66,434	73,001
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.07	0.07
Uncontrolled SO_2, lb/MMBtu (HHV) - based on 50/50 blend	7.49	7.95	8.845
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2026	0.2771
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.093	0.11
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0041	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.015	0.016
Opacity, percent	10	1.01	1.80
Ammonia (NH_3) Slip, ppmvd	2.0	0.325	
Ammonia feed rate, gal/hr	NA	3.73	6.26
Lead, lb/MMBtu	2.60×10^{-5} (max)	8.22×10^{-7}	
Mercury (fuel and limestone), µg/g	NA	3.02×10^{-7}	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 8.532 (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	Not Utilized	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	1.69×10^{-5}	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 2 for description of mercury testing anomaly.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.

TABLE 7-3 - ILLINOIS 6 COAL TEST RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	June 8, 2004 Test (**corrected to MCR, see Note 4)	June 9, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Pittsburgh 8 Coal)	88.3 (Note 1)	88.0 (Note 1)
Capacity Calculation (percent)	NA	101.5	100.0
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,974,013	1,926,677
Pressure (psig)	2,500	2,400	2,400
Temperature (°F)	1,000	998	999
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,897,211	1,859,959
Pressure (psig)	547.7	571.5	573.0
Temperature (°F)	1,000	1,005	1,011
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,897,091	1,851,738
Pressure (psig)	608.6	570.9	572.3
Enthalpy (Btu/lb)	1,304.5	1,293.6	1,285.6
Feedwater to Economizer			
Temperature (°F)	487.5	484.1	484.6
Illinois 6 Fuel Analysis (As-Received)			
Carbon %	64.48	64.93	64.70
Hydrogen %	4.40	4.31	4.57
Sulfur %	2.71	3.17	3.32
Nitrogen %	1.24	1.27	1.26
Chlorine %	0.15	0.15	0.15
Oxygen %	7.34	7.14	7.37
Ash %	8.57	7.08	6.59
Moisture %	11.11	12.10	12.19
HHV (Btu/lb)	11,603	11,649	11,664
Fuel Flow Rate (lb/hr)	NA	232,730	232,535
Limestone Composition (% By Weight)			
CaCO3	92.0	96.6	96.77
MgCO3	3.0	1.3	1.39
Inerts	4.0	2.1	1.84
Total Moisture	1.0	0.16	0.22

Parameter	Design Maximum-Continuous Rating (MCR)	June 8, 2004 Test (**corrected to MCR, see Note 4)	June 9, 2004 Test (**corrected to MCR, see Note 4)
AQCS Lime Slurry Composition (% By Weight)			
CaO (See Note 5)	85.0	46.24	46.24
MgO and inerts (See Note 5)	15.0	53.76	53.76
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	64,005	73,001
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.086	0.103
Uncontrolled SO_2, lb/MMBtu (HHV)	7.49	5.44	5.69
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2763	0.2887
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.107	0.08
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0019	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.0198	0.024
Opacity, percent	10	1.5	1.0
Ammonia (NH_3) Slip, ppmvd	2.0	< 0.5206	
Ammonia feed rate, gal/hr	NA	5.53	6.76
Lead, lb/MMBtu	2.60×10^{-5} (max)	$< 4.352 \times 10^{-7}$	
Mercury (fuel), µg/g	NA	0.50	
Mercury, lb/TBtu (at stack)	10.5 (max)	0.345	
Total Mercury Removal Efficiency, percent	No requirement	95 (see Note 2)	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 4.582 \times 10^{-5}$	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 3 for basis.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.
NOTE 5: These components were not captured for this test - average results from Test #1 and Test #2 are indicated.

TABLE 7-4 - 80/20 BLEND PET COKE AND PITT 8 COAL TEST RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	August 10, 2004 Test (**corrected to MCR, see Note 4)	August 11, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.52 ** (Note 1)	91.62 ** (Note 1)
Capacity Calculation (percent)	NA	95.6	96.05
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,901,483 **	1,910,388 **
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	914.5 **	912.4 **
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,715,491	1,723,401
Pressure (psig)	547.7	592.6	590.8
Temperature (°F)	1,000	1,001.4 **	1,000.8 **
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,715,448	1,723,361
Pressure (psig)	608.6	593.5	591.6
Enthalpy (Btu/lb)	1,304.5	1,290.1	1,289.97
Feedwater to Economizer			
Temperature (°F)	487.5	420.0	419.9
80/20 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	81.36	82.14
Hydrogen %	4.1	3.63	3.67
Sulfur %	5.0	3.7	3.74
Nitrogen %	1.15	1.93	1.95
Chlorine %	0.05	0.03	0.03
Oxygen %	2.20	1.72	0.89
Ash %	6.6	2.33	2.41
Moisture %	7.1	5.34	5.20
HHV (Btu/lb)	13,345	14,085	14,081
Fuel Flow Rate (lb/hr)	NA	186,885	186,982
Limestone Composition (% By Weight)			
CaCO3	92.0	97.55	97.23
MgCO3	3.0	1.18	1.16
Inerts	4.0	1.27	1.61
Total Moisture	1.0	0.3	0.29

Parameter	Design Maximum-Continuous Rating (MCR)	August 10, 2004 Test (**corrected to MCR, see Note 4)	August 11, 2004 Test (**corrected to MCR, see Note 4)
AQCS Lime Slurry Composition (% By Weight)			
CaO (See Note 5)	85.0	46.24	46.24
MgO and inerts (See Note 5)	15.0	53.76	53.76
AQCS Lime Slurry Density – % Solids	35	1.25	1.41
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	50,892	50,405
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.0127	0.0081
Uncontrolled SO_2, lb/MMBtu (HHV) - based on 80/20 blend	7.49	5.25	5.312
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.1150	0.1636
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.058	0.07
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0024	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.0127	0.0081
Opacity, percent	10	0.07	0.08
Ammonia (NH_3) Slip, ppmvd	2.0	0.27	
Ammonia feed rate, gal/hr	NA	3.42	1.09
Lead, lb/MMBtu	2.60×10^{-5} (max)	4.424×10^{-7}	
Mercury (fuel and limestone), µg/g	NA	0.05	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 0.07385	
Total Mercury Removal Efficiency, percent	No requirement	98 (See Note 2)	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 5.3 \times 10^{-6}$	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 4 for basis.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.
NOTE 5: These components were not captured for this test - average results from Test #1 and Test #2 are indicated.

The boiler and SDA SO_2 removal efficiencies at full load for each test are summarized in Tables 7-5 through 7-8 below.

TABLE 7-5 - SO2 REMOVAL EFFICIENCIES - 100% PITT 8 FUEL
100% Load

Parameter	Design Basis	January 13, 2004 Test	January 14, 2004 Test
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	96.8	95.8
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.8	2.7
Percent of Total SO_2 Removed	97.1	98.6	98.5
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	56.9	63.5
Boiler Calcium to Sulfur Ratio	< 2.88	1.77	1.86

TABLE 7-6 - SO2 REMOVAL EFFICIENCIES - 50/50 BLEND PITT 8 COAL AND PET COKE
100% Load

Parameter	Design Basis	January 27, 2004 Test	January 28, 2004 Test
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	97.5	96.8
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.3	1.9
Percent of Total SO_2 Removed	97.1	98.8	98.7
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	54	60.3
Boiler Calcium to Sulfur Ratio	< 2.88	1.7	2.25

TABLE 7-7 - SO2 REMOVAL EFFICIENCIES - ILLINOIS 6 COAL
100% Load

Parameter	Design Basis	June 8, 2004 Test	June 9, 2004 Test
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	94.9	95.0
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	3.17	3.7
Percent of Total SO_2 Removed	97.1	98.0	98.6
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	61.0	72.0
Boiler Calcium to Sulfur Ratio	< 2.88	2.68	2.43

TABLE 7-8 - SO2 REMOVAL EFFICIENCIES - 80/20 BLEND PET COKE AND PITT 8 COAL
100% Load

Parameter	Design Basis	August 10, 2004 Test	August 11, 2004 Test)
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	97.8	96.9
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.1	1.8
Percent of Total SO_2 Removed	97.1	98.9	98.7
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	49.5	57.0
Boiler Calcium to Sulfur Ratio	< 2.88	2.29	2.29

Note that the design operating condition of the unit is to remove 85 percent of the SO_2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. JEA has chosen to operate at a much higher boiler SO_2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO_2 emissions. Over time, the operations group has learned that if limestone feed is higher than normally desired, the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to

increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO_2 removal and increased SDA SO_2 removal.

7.4.4 Partial Load Test Results

The results of the part load tests are summarized in Tables 7-9 through 7-12 below.

TABLE 7-9 - PART LOAD TEST RESULTS - 100% PITTSBURGH 8 FUEL

Parameter	January 15	January 16	
Percent Load	80%	60%	40%
Unit Capacity (MW)	240	180	120
Total Main Steam Flow, lb/hr	1,435,543	1,070,747	738,397
Main Steam Temperature, deg F	1,003	998	999
Main Steam Pressure, psig	2,400.6	1,800.4	1,300.4
Cold Reheat Steam Temperature, deg F	576.6	572.7	565.9
Hot Reheat Steam Temperature, deg F	1,005	1,006	1,004
NOx, lb/MMBtu	0.080	0.072	0.082
CO, lb/MMBtu	0.044	0.118	0.053
SO2, lb/MMBtu	0.082	0.081	0.108
Opacity, percent	1.0	1.5	1.4

TABLE 7-10 - PART LOAD TEST RESULTS - 50/50 BLEND PITT 8 COAL AND PET COKE

Parameter	January 29	January 30	January 31
Unit Capacity (MW)	240	180	120
Percent MCR Load	80%	60%	40%
Capacity Calculation (percent)	76.6	58.0	38.2
Total Main Steam Flow, lb/hr	1,442,226	1,049,633	715,464
Main Steam Temperature, deg F	1,004	993	997
Main Steam Pressure, psig	2,340	1,701	1,062
Cold Reheat Steam Temperature, deg F	577.5	558.02	573.64
Hot Reheat Steam Temperature, deg F	1,006	1,011	999
NOx, lb/MMBtu	0.04	0.043	0.033
CO, lb/MMBtu	0.024	0.0276	0.08
SO2, lb/MMBtu	0.08	0.067	0.109
Opacity, percent	1.4	1.1	0.8

TABLE 7-11 - PART LOAD TEST RESULTS - ILLINOIS 6 COAL

Parameter	June 9	June 8	June 9
Percent Load	80%	60%	40%
Unit Capacity (MW)	240	180	120
Capacity Calculation (percent)	82.21	55.50	38.27
Total Main Steam Flow, lb/hr	1,541,871	1,087,192	715,411
Main Steam Temperature, deg F	1,001	1,002	1,001
Main Steam Pressure, psig	2,400	1,700	1,200
Cold Reheat Steam Temperature, deg F	561	575	561
Hot Reheat Steam Temperature, deg F	1,007	966	1,004
NOx, lb/MMBtu	0.064	0.053	0.078
CO, lb/MMBtu	0.031	0.0338	0.138
SO2, lb/MMBtu	0.079	0.144	0.108
Opacity, percent	1.3	1.6	1.4

TABLE 7-12 - PART LOAD TEST RESULTS - 80/20 BLEND PET COKE AND PITT 8 COAL

Parameter	Aug. 12	Aug. 13
Unit Capacity (MW)	240	180
Percent MCR Load	80%	60%
Capacity Calculation (percent)	76.51	54.69
Total Main Steam Flow, lb/hr	1,393,557	1,021,784
Main Steam Temperature, deg F	980.55	980.62
Main Steam Pressure, psig	2,200.14	1,450.21
Cold Reheat Steam Temperature, deg F	579.46	595.45
Hot Reheat Steam Temperature, deg F	984.03	992.10
NOx, lb/MMBtu	0.027	0.018
CO, lb/MMBtu	0.0147	0.0218
SO2, lb/MMBtu	0.054	0.058
Opacity, percent	1	1

7.5 Boiler Efficiency Tests

For each test, the unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in the Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency.

7.5.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO_2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcination / sulfation. A complete description of the modified procedures is included in Section 4.2 of the Fuel Capability Demonstration Test Protocol. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the fly ash, and the heat loss due to radiation and convection from the insulated boiler surfaces.

7.5.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. Additional data required for the boiler efficiency calculations were collected by two independent testing contractors, Power Generation Technologies (PGT), and Clean Air Engineering (CAE).

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the PI system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, fly ash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis.

<u>Lime:</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Fly ash:</u>

Fly ash samples were taken by two different methods.

1) Flyash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Flyash was also taken by grab sample method in two different locations. One grab sample was taken every hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel:</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

Limestone:

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

Bed Ash:

Bed ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

All of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation.

7.6 AQCS Inlet and Stack Tests

7.6.1 System Description

The Unit 2 AQCS consists of a single, lime-based SDA and a multi-compartment PJFF. The SDA has sixteen independent dual-fluid atomizers. The PJFF has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Flyash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime, which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

7.6.2 Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – Conditional Test Method 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans (PCDD/F) – USEPA Method 23

7.6.3 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration, as listed above. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NO_x, SO_2, and CO_2 analyzers. The test data from the CEMS originated from the certified Data Acquisition Handling System (DAHS).

8.0 CAPITAL COSTS

8.1 Capital Cost History/Overview

At the time JEA and the DOE signed the Cooperative Agreement for the Large-Scale CFB Combustion Demonstration Project for Northside Unit 2 in September 1997, the preliminary budget estimate for Repowering Unit 2 with CFB boiler technology, plus one-half of the cost of the associated common facilities, totaled $305, 773,774. This preliminary budget estimate was used as the basis for cost sharing throughout the project life.

The preliminary project capital cost estimate increased due to refined scope definitions, improved cost estimates, and scope growth. To identify and quantify the magnitude of this increase, the project "Baseline" estimate was developed in October 2000. The "Baseline" or "Control" estimate was the joint effort by the key principles making up the project team. Estimates, based on firm scope and significant detail design, were developed by JEA, FW, B&V, FGS, and ZCC for their areas of the project. This estimate resulted in a revised budget for Unit 2 and one-half of the common facilities to $328,878,487.

At project completion, the actual capital cost for Unit 2 and one-half of the associated common facilities totaled $321,392,624, only about 5% above the original preliminary budget estimate. A breakdown of these costs by DOE Phase and Task is provided in Appendix D.

DOE financial support and limitations on DOE funding, as set forth in the Cooperative Agreement, were tied to the preliminary budget estimate. Within that budget of $305,773,774, DOE would share fifty percent (50%) of Phase 1B (Design) cost up to $11,484,482; JEA's actual portion of Phase 1B at completion totaled $22,549,532. Within Phase 2 (Construction and Start-up), DOE would share at a rate of twenty eight point three percent (28.3%) up to $59,243,317; JEA's actual portion of Phase 2 at completion totaled $228,115,293. During Phase 3 (Operations), the DOE share would total $2,344,655. The Phase 3 funds were tied to a milestone schedule for final issue of the demonstration test reports. At project completion the DOE cost share in the project is expected to be a total of $73,072,464, with the JEA cost share being $250,664,825.

8.2 Capital Improvement Projects - Phase 1

Problems with Unit 2 reliability and maintainability were encountered early in plant operations. As a result, JEA began targeting capital funds, in addition to O&M funds being expended, to mitigate and resolve many of the problems being experienced. These projects were identified as Phase 1 Completion Modifications, and are described in more detail in the Start-up Modifications Report, which is available on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/Start-Up%20Modifications%20Report_final.pdf

These Phase 1 Completion Modifications, hereinafter referred to as Capital Improvement Projects, were executed during FY 02/03 at a capital cost of $5,697,156. A description of these projects and associated costs is provided in Appendix D.

8.3 Capital Improvement Projects - Phase 2

Continuing significant operating and reliability issues lead to the identification of additional improvement projects, referred to as Phase 2 Capital Improvement Projects. These projects were implemented during FY 03/04 at a capital cost of $7,138,138. A description of these projects and associated costs is also provided in Appendix D.

8.4 Capital Improvement Projects Going Forward

Although the Cooperative Agreement between DOE and JEA is expected to be completed in April 2005, JEA is continuing to proactively investigate and implement (where appropriate) capital outlays to improve EAF and maintainability of the repowered units.

8.5 Commercialization of Large Scale CFB Combustion Technology

The JEA Large Scale CFB Combustion Demonstration Project has demonstrated the successful commercial operation of a 300 MW class CFB boiler firing both domestic coals and petroleum coke, and coal/coke blends. The operating data summarized in Section 5 of this report confirms that the Unit 2 CFB boiler is capable of routinely supporting full load operation of Unit 2 while achieving stack emissions below permit limits. The performance test results in Section 7 of this report confirm that the as-tested full load boiler efficiencies on various fuels were at or above the design values developed by FW, and are competitive with the boiler efficiencies achieved by other commercially available boiler technologies of this size.

However, the operating data in Section 5 also indicates that the EAF for Unit 2 during the two year demonstration period for the project was significantly lower than industry average values, based on a comparison to NERC/GADS data. The majority of the lost MW hours were caused by boiler related problems, and JEA has spent over 12 million dollars on capital improvement projects during the two year demonstration period to improve the reliability and maintainability of the Unit 2 CFB boiler and AQCS system. Refer to Section 6 of this report for a description of some of the significant modifications that have been made. The associated capital costs are summarized in this Section 8 of the report. In addition, JEA anticipates that significant additional capital expenditures will be required over the next 5 years, primarily on the boilers, to raise the EAF of Units 1 and 2 to near industry average values.

The most significant boiler related problem affecting EAF encountered during the demonstration period has been agglomeration and superheater tube failures in the Intrex, as described in Section 6 of this report. Investigations by JEA and FW of the issues involved and long term modifications to mitigate these issues on the Northside CFB boilers are ongoing. Options being considered include removal of the superheater surface from the Intrex. FW has already concluded that the Intrex design is not viable, and is no longer offering this design feature on new CFB boilers.

APPENDICES

Appendix A - Drawings

Appendix B - Equipment List

Appendix C - Unit 2 Operating Data

Appendix D - Capital Cost Data

APPENDIX A - Drawings

OVERALL PLOT PLAN

CMA-S1000	Site Arrangement
4600-1-51-004	Overall plot plan

CFB BOILERS

43-7587-5-51	GENERAL ARRANGEMENT UNIT 2 SIDE ELEVATION
43-7587-5-52	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (FRONT)
43-7587-5-53	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (RIGHT SIDE)
43-7587-5-54	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (LEFT SIDE)
43-7587-5-55	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (REAR)
43-7587-5-20	STEAM GENERATOR GENERAL ARRANGEMENT CROSS SECTION

AIR QUALITY CONTROL SYSTEM

3847-1-100	GEN ARRANGEMENT PLAN
3847-1-101	GEN ARRANGEMENT ELEVATION
3847-1-102	GEN ARRANGEMENT ELEVATION
3847-1-103	GEN ARRANGEMENT ELEVATION

WATER MASS BALANCE DIAGRAM

WMB-1	WATER MASS BALANCE, ANNUAL AVERAGE, CELL 1 OF BSA ONLY

APPENDIX B - Major Equipment List

The Equipment List on the following pages lists the major equipment associated with the Repowering Project and is listed by the JEA GEMS (or System) Code. Since the P&ID's are defined and numbered by their associated GEMS code, the equipment is also listed by P&ID. The quantity, percent capacity, and redundancy is indicated for each item of equipment. This information is indicated for Unit 2, Common, and Unit 1 equipment, since some items of equipment serve as an installed back-up for both units.

JEA Large-Scale CFB Demonstration Project
Major Equipment List

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
AB	INSTRUMENT AIR DRYERS		3		Nominal 50% Capacity Each	Serve Units 1, 2, and 3
AC	AIR COMPRESSORS		6		Nominal 25% Capacity Each	Provide Service and Instrument Air for Units 1, 2, and 3
BB	STEAM GENERATOR	1		1		
BB	STEAM DRUM	1		1		
BC	SECONDARY AIR TUBULAR AIR HEATER	1		1		
BC	PRIMARY AIR TUBULAR AIR HEATER	1		1		
BF	ELBOW DUCT BURNERS	3		3		For Start-up Only
BF	ABOVE BED BURNERS	3		3		100 MMBtu per Hour each
BI	SOOTBLOWER PRIMARY SUPERHEATER	8		8		
BI	SOOTBLOWER FINAL REHEATER	6		6		
BI	SOOTBLOWER REHEATER	6		6		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
BI	SOOTBLOWER ECONOMIZER	16		16		
BK	BOILER BLOWDOWN DRUM	1		1		
BN	PRIMARY AIR FAN	2		2	50% Capacity Each	
BN	SECONDARY AIR FAN	2		2	50% Capacity Each	
BN	PRIMARY AIR FAN LUBE OIL SKID	2		2		One per Fan
BO	INDUCED DRAFT FAN	2		2	50% Capacity Each	
BO	ID FAN INLET ISOLATION DAMPER	2		2		One per Fan
BO	ID FAN OUTLET ISOLATION DAMPER	2		2		One per Fan
BO	CONCRETE CHIMNEY		1			With Separate Flue for Each Unit
EF	MCC/LOAD CENTER/SWITCHGEAR	1 LOT	1 LOT	1 LOT		Essentially all MCC's, Load Centers, and Switchgear were replaced for Unit 2, Common, and Unit 1 Equipment
FG	FUEL UNLOADING DOCK		1			
FH	COINTINUOUS SHIP UNLOADER		1			
FH	COKE/COAL BELT CONVEYORS TO DOMES		7			Single String of Conveyors to Storage Domes

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
FH	COKE/COAL STORAGE DOMES		2		85,000 Tons per Dome	
FH	RADIAL STACKER RECLAIMER		2		100% Capacity Each	One per Dome - Serve Units 1 and 2
FH	SILO FILL COKE/COAL CONVEYORS		8		100% Capacity Each	Two Full Capacity Strings of Conveyors - Serve Units 1 and 2
FH	COKE/COAL CRUSHER		2		100% Capacity Each	Serve Units 1 and 2
FH	COKE/COALTRAVELING TRIPPER		2		100% Capacity Each	Serve Units 1 and 2
FN	BOILER COAL/COKE SILO	5		5		
FN	COKE/COAL DRAG CONVEYOR	2		2		For Rear Wall Feed
FN	COKE/COAL GRAVAMETRIC FEEDER	8		8		
GA	GENERATOR	1		1		
GC	MAIN SEAL OIL PUMP	1		1		
GC	EMERGENCY SEAL OIL PUMP	1		1		
GC	SEAL OIL VACUUM PUMP	1		1		
GC	SEAL OIL TANK	1		1		
GI	STATOR COOLING WATER PUMP	2		2	100% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
GI	DEIONIZER	1		1		
GI	STATOR COOLING WATER STORAGE TANK	1		1		
GI	STATOR COOLING WATER COOLERS	2		2	100% Capacity Each	
HB	NASH VACUUM PUMP	1	1	1	100% Capacity Each	
HD	BITTER WATER PUMP	1		1		
HD	BOILER FILL PUMP	1				Serves Units 1, 2, and 3
HF	CONDENSATE BOOSTER PUMP	2		2	100% Capacity Each	With Variable Speed Fluid Drives
HF	BED ASH COOLING WATER PUMP	2		2	100% Capacity Each	
HF	DEAERATOR (FWH 3) STORAGE TANK	1		1		
HF	DEAERATOR (FWH 3) HEATER SECTION	1		1		
HF	FEED WATER HEATER NO. 4	1		1		
HF	FEED WATER HEATER NO. 5	1		1		
HF	FEED WATER HEATER NO. 6	1		1		
HK	HEATER DRAIN PUMP	2		2	100% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
HK	FEED WATER HEATER NO. 6 HOTWELL	1		1		
HP	SULFURIC ACID MIXING SKID	1				
HP	CAUSTIC MIXING SKID	1				
HP	POLISHER RECYCLE PUMP	1		1		
HP	POLISHER SLUICE PUMP			1		
HP	POLISHER REGENERATION WATER PUMP	1				
HP	CAUSTIC RECYCLE PUMP	1				
HP	CONDENSATE POLISHER VESSEL	3		3	50% Capacity Each	
HP	CONDENSATE POLISHER SEPARATION AND ANION REGENERATION VESSEL	1		1		
HP	CONDENSATE POLISHER CATION REGENERATION VESSEL	1		1		
HP	CONDENSATE POLISHER MIX AND HOLD VESSEL	1		1		
HP	CONDENSATE POLISHER HOT WATER TANK	1		1		
HP	WASTE INSPECTION TANK	1				
HP	POLISHER RESIN TRAP	3		3		One per Polisher Vessel

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
IB	TRAVELING WATER SCREENS	2		2	50% Capacity Each	
IB	SCREEN WASH PUMPS		2			Serve Units 1, 2, and 3
MA	BOILER FREIGHT ELEVATOR	1		1		
MJ	BOILER SAMPLE PANEL CHILLER	1		1		
MJ	BOILER SAMPLE PANEL	1		1		
MJ	SAMPLE PANEL	1				
MJ	SAMPLE CHILLER	1				
NA	FLY ASH SILO	1		1		Fly Ash from either Unit 2 or Unit 1 can be directed to either silo
NA	FLY ASH SILO FILTER/SEPARATOR	2		2	100% Capacity Each	Fly Ash from either Unit 2 or Unit 1 can be directed to either silo
NA	FLY ASH SILO VENT FILTER	1		1		
NA	AQCS RECYCLE BIN FILTER/SEPARATOR	1		1		
NA	FLY ASH HEAD CIRCULATION PUMP	1		1		
NA	DENSE ASH SLURRY MIXING TANK FEED PUMP	2		2	50% Capacity Each	
NA	STANDBY AIR COMPRESSOR		1			

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NA	PRIMARY AIR COMPRESSOR		1			
NA	FLY ASH SLURRY MIXING TANK	1		1		
NA	FLY ASH VACUUM EXHAUSTER		4		100% Capacity Each	Crosstied to serve either Unit 2 or Unit 1
NA	BED ASH CROSS CONVEYOR		2			Between Unit 2 and Unit 1 Bed Ash Silo Outlets
NA	BED ASH CLINKER GRINDERS	1		1		Above Dense Ash Slurry Mixing Tank
NA	DENSE ASH SLURRY MIXING TANK	1		1		
NA	DENSE ASH HEAD CIRCULATION PUMP	1		1		
NA	DENSE ASH SLURRY BOOSTER PUMP	2		2	100% Capacity Each	
NA	DENSE ASH SLURRY PISTON DIAPHRAGM PUMP		2		100% Capacity Each	
NA	EMERGENCY FLUSH PUMP		1			
NB	BED ASH SILO	1		1		Bed Ash from either Unit 1 or Unit 2 can be directed to either silo
NB	BED ASH PRESSURE AIRLOCK VESSEL	4		4		
NB	BED ASH SURGE HOPPER	1		1		
NB	SIDE WALL STRIPPER/ COOLER	2		2		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NB	FRONT WALL STRIPPER COOLER	2		2		
NB	BED ASH SURGE HPR. VENT FILTER	1		1		
NB	BED ASH SILO VENT FILTER	1		1		
NB	ASH CLR. DISCHARGE CONVEYOR	4		4		One from each Stripper Cooler
NB	BED ASH GATHERING CONVEYOR	2		2		
NB	BED ASH CLINKER GRINDER	2		2		Above Bed Ash Surge Hopper
NB	BED ASH TRANSPORT BLOWER		3		100% Capacity Each	Crosstied to serve either Unit 2 or Unit 1
NB	BED ASH SURGE HOPPER VENT FILTER EXHAUST FAN	1		1		
NL	REUSE WATER ACID FEED PUMP SKID		1			
NL	REUSE WATER INHIBITOR FEED PUMP SKID		1			
NL	REUSE WATER CHEMICAL FEED STATIC MIXER		1			
NL	REUSE WATER SUPPLY PUMP		2		100% Capacity Each	
NL	CSU REUSE WATER BOOSTER PUMP		1			
NL	REUSE WATER STORAGE TANK		1			

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NN	BSA SUMP		4			
NN	BSA SUMP PUMPS		8			Two Pumps per Sump
NN	BSA LEACHATE DETECTION SUMP		4			
NN	BSA LEACHATE DETECTION SUMP PUMP		8			Two Pumps per Sump
NN	BSA POND EFFLUENT SUMP		1			
NN	BSA POND EFFLUENT SUMP PUMP		2			
NN	WASTEWATER COLLECTION SUMP 12		1			
NN	WASTEWATER COLLECTION SUMP 12 SUMP PUMP		2			
NN	FUEL STORAGE DOME SUMP 13		1			
NN	FUEL STORAGE DOME SUMP 13 SUMP PUMP		2			
NN	SUBSURFACE DRAIN SUMP		3			
NN	SUBSURFACE DRAIN SUMP PUMP		6			Two Pumps per Sump
NN	BOILER SUMP	1		1		
NN	BOILER SUMP PUMP	2		2		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NN	AQCS SUMP	1		1		
NN	AQCS SUMP PUMP	2		2		
NN	ELEVATOR SHAFT SUMP PUMP	1		1		
QB	BOILER FEED PUMP	2		2	50% Capacity Each	One motor driven, one turbine shaft driven. With variable speed fluid drives.
QB	BOILER FEED PUMP SEAL WATER LEAK OFF RECOVERY TANK	1		1		
QF	FEED WATER HEATER NO. 2	1		1		
QF	FEED WATER HEATER NO. 1	1		1		
RA	AQCS GLYCOL CIRCULATING PUMP		2		100% Capacity Each	Serve Unit 2 and Unit 1
RA	AQCS ATOMIZING AIR COMPRESSOR	1	1	1	100% Capacity Each	
RA	AQCS ATOMIZING AIR RECEIVER		1			Serves Unit 2 and Unit 1
RA	AQCS GLYCOL/WATER SURGE TANK		1			Serves Unit 2 and Unit 1
RA	ATOMIZING AIR COMPRESSOR INLET AIR FILTER/SILER.	1	1	1		One per Compressor
RA	ATOMIZING AIR COMPRESSOR UNLOADING SILER.	1	1	1		One per Compressor
RA	LIME SLURRY FEED PUMP	2		2	100% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RA	RECYCLE SLURRY TRANS. PUMP	2		2	100% Capacity Each	
RA	FEED SLURRY TRANS. PUMP	2		2	100% Capacity Each	
RA	FEED SLURRY PUMP	2		2	100% Capacity Each	
RA	AQCS FLUIDIZING AIR BLOWER	3		3	50% Capacity Each	
RA	AQCS FLUIDIZING AIR HEATER	3		3	50% Capacity Each	
RA	LIME SLURRY STORAGE TANK AGITATOR	1		1		
RA	RECY SLURRY STORAGE TANK AGITATOR	1		1		
RA	RECY SLURRY MIX TANK AGITATOR	1		1		
RA	LIME SLURRY STORAGE TANK	1		1		
RA	RECYCLE SLURRY MIX TANK	1		1		
RA	RECYCLE SLURRY STORAGE TANK	1		1		
RA	FLY ASH RECYCLE STORAGE BIN	1		1		
RA	FEED SLURRY HEAD TANK	1		1		
RA	SDA BIN ACTIVATOR	1		1		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RA	FLY ASH RECYCLE FEEDER	2		2	100% Capacity Each	
RA	SDA ASH CONVEYOR	1		1		
RA	SDA EMERGENCY DISCHARGE CONVEYOR	1		1		
RA	SDA ASH DELUMPER	1		1		
RA	SDA IMPACTOR	3		3		
RB	FABRIC FILTER COMPARTMENT	8		8		
RB	AQCS INSTRUMENT AIR DRYER		2		100% Capacity Each	Serve Unit 2 and Unit 1
RH	LIMESTONE STACK-OUT CONVEYOR		1			
RH	LIMESTONE FEED CONVEYORS TO LS PREP		3			One per Dryer/Mill Train
RH	LS PLANT AIR COMPRESSOR		2			Serve Unit 2 and Unit 1
RH	LS AIR HEATER COMBUSTION AIR FAN		3			One per Dryer/Mill Train
RH	LS DRYER/MILL DUST COLL EXHAUST FAN		3			One per Dryer/Mill Train
RH	LS PREP. DUST COLLECTOR EXHAUST FAN		3			One per Dryer/Mill Train
RH	LS PRODUCT PNEUMATIC BLOWER		3			One per Dryer/Mill Train

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RH	LS PLANT AIR RECEIVER		2			Serve Unit 2 and Unit 1
RH	LIMESTONE PRODUCT SURGE BIN		3			One per Dryer/Mill Train
RH	LS AIR HEATER		3			One per Dryer/Mill Train
RH	LIMESTONE PREP. DUST COLLECTOR		3			One per Dryer/Mill Train
RH	LIMESTONE DRYER/MILL DUST COLL		3			One per Dryer/Mill Train
RH	LIMESTONE PRODUCT SCREEN		6			Two per Dryer/Mill Train
RH	LS PLANT AIR DRYER		2			Serve Unit 2 and Unit 1
RH	LIMESTONE PROD. ELEV CONVEYOR		3			One per Dryer/Mill Train
RH	LIMESTONE SCREEN FEEDER		3			One per Dryer/Mill Train
RH	LS SCREEN PRODUCT SCREW CONV.		3			One per Dryer/Mill Train
RH	LIMESTONE DRYER/MILL		3		100% Capacity Each for 1 Unit	Each Dryer/Mill Train can supply either Unit 2 or Unit 1
RH	RAW LIMESTONE IMPACTOR		3			One per Dryer/Mill Train
RL	AQCS MILL RECYCLE FEED PUMP		2		100% Capacity Each	Serve Unit 2 and Unit 1
RL	AQCS LIME SLURRY TRANSFER PUMP		4		100% Capacity Each	Serve Unit 2 and Unit 1

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RL	AQCS LIME SLURRY TRANS. TANK AGITATOR		2			Serve Unit 2 and Unit 1
RL	AQCS LIME STORAGE SILO		1			Serves Unit 2 and Unit 1
RL	AQCS LIME SLURRY TRANSFER TANK		2			Serves Unit 2 and Unit 1
RL	AQCS MILL SEPARATING CHAMBER		2			Serves Unit 2 and Unit 1
RL	AQCS LIME STORAGE SILO BIN ACTIVATOR		1			Serves Unit 2 and Unit 1
RL	AQCS LIME STORAGE SILO DUST COLLECTOR		1			Serves Unit 2 and Unit 1
RL	AQCS MILL VENT SCRUBBER		2			Serves Unit 2 and Unit 1
RL	AQCS VERTICAL BALL MILL SLAKER		2			Serves Unit 2 and Unit 1
RN	LIMESTONE BLOWER	3		3	33-1/3% Capacity Each	
RN	STANDBY LIMESTONE BLOWER	1		1		
RN	LIMESTONE SILO	1		1		
RN	LIMESTONE FILTER/RECEIVER	3		3		
RN	LIMESTONE SILO VENT FILTER	1		1		
RN	LIMESTONE FILTER/REC. EXHAUSTER	3		3		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RN	LIMESTONE ROTARY FEEDER	3		3		
RN	LIMESTONE ROTARY AIRLOCK FEEDER	6		6		
RN	LIMESTONE ROTARY VALVE	3		3		
SI	INTREX™	3		3		
SI	INTREX™ BLOWER	3		3	50% Capacity Each	
SI	SEAL POT BLOWER	3		3	50% Capacity Each	
SJ	ERV SILENCER	1		1		
SK	CYCLONE	3		3		
SL	ECONOMIZER	1		1		
TG	STEAM TURBINE - LP	1		1		
TH	STEAM TURBINE - HP/IP	1		1		
TI	STEAM PACKING EXHAUSTER	1		1		
TJ	TURB LUBE OIL HEAT EXCHANGERS	2		2	100% Capacity Each	
TJ	TURBINE LUBE OIL CONDITIONER	2		2		One Bowser, One Turbo-Toc

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
TJ	TURBINE LUBE OIL TANK	2		2		One Operating Tank, One Storage Tank
TJ	TURBINE LUBE OIL PUMP	3		3		Two AC, One DC
TN	TURBINE ELECTRO-HYDRAULIC CONTROL UNIT	1		1		
UE	HYDRAZINE FEED PUMP	1		1		
UE	AMMONIA FEED PUMP	1		1		
UE	PHOSPHATE FEED PUMP	2		2	100% Capacity Each	
UE	PHOSPHATE STORAGE TANK	1		1		
UE	PHOSPHATE STG. TANK AGITATOR	1		1		
UR	AMMONIA PUMP	1	1	1	100% Capacity Each	Common Shared Spare
UR	AMMONIA STORAGE TANK		1			Serves Units 2 and 1
WF	DEMINERALIZED WATER TRANSFER PUMPS		2			Added Demin Water from SJRPP for Units 1, 2, and 3
XE	CONDENSATE PUMP	2		2	100% Capacity Each	
XE	CONDENSER	1		1		
XE	DEBRIS FILTERS	2		2	50% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
XJ	RIVER WATER BOOSTER PUMP	2		2	100% Capacity Each	
XK	CLOSED COOLING WATER PUMP	2		2	100% Capacity Each	
XK	CLOSED COOLING WATER BOOSTER PUMP	2		2	100% Capacity Each	
XK	CLOSED COOLING WATER SURGE TANK	1		1		
XK	CLOSED COOLING WATER PLATE HEAT EXCHANGER	2		2	100% Capacity Each	
XL	CIRCULATING WATER PUMP	2		2	50% Capacity Each	

APPENDIX C - Unit 2 Operating Data

Northside Unit 2 Operating Data
October 2002 thru December 2004

FILE: (0)JEADATA	DRAKE																		
		CALENDAR 2003	CALENDAR 2004	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
FUEL HEAT CONTENT																		
NS-2 PETCOKE	HEAT CONTENT-BTU/LB	14,107	13,949	14,133	13,893	14,240	14,321	14,257	14,182	14,042	13,932	14,273	14,215	14,044	14,263	14,002	13,973	13,950
NS-2 COAL	HEAT CONTENT-BTU/LB	12,827	11,907	13,044	12,874	12,901	12,985	13,012	12,943	13,092	13,152	13,064	13,077	13,125	12,674	12,328	12,380	12,156
NS-2	PETCOKE %S	5.28	4.53	5.43	4.77	4.13	3.73	5.84	6.66	5.55	5.23	4.25	5.71	5.87	5.42	5.13	5.97	4.02
NS-2	COAL %S	2.52	2.62	2.65	2.82	2.76	2.42	2.39	2.44	2.54	2.48	2.65	2.73	2.63	2.30	2.36	2.57	2.69
NS-2	PETCOKE %ash	0.42	0.71	0.36	0.42	0.38	0.34	0.41	0.27	0.41	0.49	0.47	0.34	0.34	0.36	0.63	0.57	0.46
NS-2	COAL %ash	8.10	8.81	7.84	8.14	8.11	8.03	7.86	7.61	7.70	7.79	7.92	8.16	8.15	8.33	8.10	8.25	9.28
NS-2 OPER DATA	(GROSS CAP) 297.5			297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5
	GROSS MWH GENERATED	1,791,221	1,459,351	122,429	70,505	114,822	130,431	144,719	188,780	50,944	196,907	207,850	195,162	123,728	134,363	164,859	41,415	212,063
	HOUSE LOAD MWH (ON-LINE)	117,240	101,924	10,444	10,570	8,577	9,595	10,924	14,937	4,145	14,266	11,357	11,159	7,546	8,048	10,568	3,648	11,049
	NET MWH (ON-LINE)	1,673,981	1,357,427	111,985	59,935	106,245	120,836	133,795	173,844	46,799	182,641	196,493	184,003	116,182	126,315	154,291	37,767	201,014
	GAS ON-LINE (KCF)	17,262	9,904	221	759	1,587	0	1,817	17	4,378	0	0	1,717	0	0	6,985	1,841	0
	PETCOKE ON-LINE (TONS)	437,099	326,250	26,603	7,389	24,154	28,929	35,520	48,300	11,684	45,761	49,879	47,972	32,720	30,503	41,601	10,120	53,522
	COAL ON-LINE (TONS)	139,343	159,871	12,625	17,580	12,101	10,560	10,801	12,346	5,327	16,701	13,730	15,176	10,162	12,761	12,416	4,429	14,784
	LIMESTONE	229,523	180,339	17,108	6,365	9,510	12,341	21,837	30,522	6,767	23,431	19,888	31,027	19,793	15,303	21,980	7,229	19,443
	HEAT CONTENT - GAS	1,057	1,034	1,051	1,054	1,054	1,060	1,058	1,054	1,057	1,061	1,063	1,064	1,058	1,058	1,054	1,050	1,047
	HEAT CONTENT - PETCOKE	14,107	13,949	14,133	13,893	14,240	14,321	14,257	14,182	14,042	13,932	14,273	14,215	14,044	14,263	14,002	13,973	13,950
	HEAT CONTENT - COAL	12,827	11,907	13,044	12,874	12,901	12,985	13,012	12,943	13,092	13,152	13,064	13,077	13,125	12,674	12,328	12,380	12,156
	HEAT RATE (O/L) (BTU/KWH, NET)	9,514	9,518	9,658	10,991	9,429	9,127	9,685	9,719	10,091	9,387	9,072	9,579	10,206	9,449	9,584	10,445	9,216
	ATTEMPTED STARTS	18	31	5	9	4	2	1	0	8	0	0	1	0	2	1	2	1
	STARTS	15	9	1	4	2	1	1	0	7	0	0	1	0	1	1	2	1
	HOURS ONLINE	6,843	5,450	453.62	304.20	456.47	493.20	535.47	744.00	227.77	744.00	720.00	725.50	441.97	537.63	724.03	218.72	731.13
	COMBUSTION HOURS	7,057	5,839	498.50	359.53	488.43	517.08	586.33	744.00	264.42	744.00	720.00	744.00	442.45	562.53	744.00	243.98	744.00
	MBTUs GAS	71,578	100,073	8,544	3,603	6,746	6,196	19,001	18	17,221	0	0	6,163	0	5,943	7,363	5,637	4,037
	MBTUs PETCOKE	12,359,656	9,148,226	753,749	206,871	692,649	834,198	1,018,439	1,369,951	336,196	1,275,106	1,423,873	1,363,830	919,015	872,260	1,164,979	287,891	1,493,919
	MBTUs COAL	3,584,539	3,827,410	330,140	456,087	314,376	276,083	282,654	319,583	142,918	439,302	358,723	396,922	266,762	324,247	306,122	111,618	359,606
	TOTAL MBTUs	16,016,637	13,076,471	1,092,467	666,562	1,013,771	1,116,476	1,320,094	1,689,552	496,334	1,714,408	1,782,596	1,767,066	1,185,777	1,202,591	1,478,716	405,359	1,857,668
	% GAS	0.45%	0.77%	0.78%	0.54%	0.67%	0.55%	1.44%	0.00%	3.47%	0.00%	0.00%	0.35%	0.00%	0.49%	0.50%	1.39%	0.22%
	% PETCOKE	77.17%	69.96%	69.00%	31.04%	68.32%	74.72%	77.15%	81.08%	67.74%	74.38%	79.88%	77.18%	77.50%	72.53%	78.78%	71.02%	80.42%
	% COAL	22.38%	29.27%	30.22%	68.42%	31.01%	24.73%	21.41%	18.92%	28.79%	25.62%	20.12%	22.46%	22.50%	26.96%	20.70%	27.54%	19.36%
	LOAD FACTOR (GROSS)	88.0%	90.0%	90.7%	77.9%	84.6%	88.9%	90.8%	85.3%	75.2%	89.0%	97.0%	90.4%	94.1%	84.0%	76.5%	63.6%	97.5%
	CAPACITY FACTOR (GROSS)	68.7%	55.8%	55.3%	32.9%	51.9%	58.9%	72.4%	85.3%	23.8%	89.0%	97.0%	88.2%	55.9%	62.7%	74.5%	19.3%	95.8%
	MWHs GAS	6,725	7,743	833	306	664	635	1,830	2	1,483	0	0	612	0	585	733	427	417
	MWHs PETCOKE	1,281,223	928,734	76,958	18,391	71,426	89,554	102,734	140,959	30,313	135,841	156,951	141,927	87,099	89,889	121,402	22,847	161,708
	MWHs COAL	369,948	385,473	33,707	40,546	32,419	29,638	28,513	32,883	12,886	46,800	39,541	41,306	25,282	33,414	31,901	8,858	38,925
	12 mth rolling CAP FACTOR			32.0%	34.7%	39.1%	44.1%	49.4%	56.2%	56.5%	58.4%	62.7%	67.1%	66.2%	64.5%	66.1%	65.0%	68.7%
STACK EMISSIONS DATA - UNIT 2																		
	SO2 Emissions, Tons	1,131.8	1,095.6	123.5	131.4	112.5	94.0	124.9	117.1	34.4	83.3	82.4	125.7	72.2	77.1	131.6	74.3	114.8
	SO2 Emissions, lb/MBtu	0.14	0.17	0.23	0.39	0.22	0.17	0.19	0.14	0.14	0.10	0.09	0.14	0.12	0.13	0.18	0.37	0.12
	NOx Emissions, Tons	525.5	492.6	30.5	46.7	24.8	38.1	51.9	48.5	27.4	51.8	66.4	43.7	37.3	34.1	29.3	28.4	68.6
	NOx Emissions, lb/Mbtu	0.07	0.08	0.06	0.14	0.05	0.07	0.08	0.06	0.11	0.06	0.07	0.05	0.06	0.06	0.04	0.14	0.07
	Particulate Matter, Tons	41.23	29.72	2.19	1.33	2.03	5.95	7.01	2.53	0.76	2.57	2.67	4.42	2.96	3.01	3.70	1.01	4.64
	Particulate Matter, lb/Mbtu	0.005	0.005	0.004	0.004	0.004	0.011	0.011	0.003	0.003	0.003	0.003	0.005	0.005	0.005	0.005	0.005	0.005
	CO, Tons	297.3	290.6	36.7	36.6	33.4	27.7	63.2	29.1	33.9	27.0	7.4	18.9	7.3	16.0	33.9	14.7	18.2
	CO, lb/Mbtu	0.04	0.04	0.07	0.11	0.07	0.05	0.10	0.03	0.14	0.03	0.01	0.02	0.01	0.03	0.05	0.07	0.02
	CO, lb/hr	84	100	147	204	137	107	216	78	256	73	21	51	33	57	91	121	49
	VOC, Tons	11.92	11.63	1.47	1.46	1.34	1.11	2.53	1.16	1.36	1.08	0.29	0.76	0.29	0.64	1.40	0.60	0.70
	VOC, lb/Mbtu	0.001	0.002	0.003	0.004	0.003	0.002	0.004	0.001	0.005	0.001	0.000	0.001	0.000	0.001	0.002	0.003	0.001
	VOC, lb/hr	3.4	4.0	5.9	8.1	5.5	4.3	8.6	3.1	10.3	2.9	0.8	2.0	1.3	2.3	3.8	4.9	1.9
GADS DATA																		
	Equivalent Availability Factor, EAF, %	72.8%	58.7%	Incompl Data	Incompl Data	Incompl Data	63.90%	78.70%	86.82%	29.65%	93.40%	99.76%	94.35%	57.22%	68.13%	77.24%	27.06%	97.58%

Northside Unit 2 Operating Data
October 2002 thru December 2004

FILE: (0)JEADATA	DRAKE	CALENDAR 2003	CALENDAR 2004	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
WATER AND WASTEWATER FLOWS (UNITS 1, 2, AND 3)																		
	Surface Water, Million Gallons	285,493	278,776	23,193	21,619	23,879	25,130	15,194	24,013	20,190	22,843	26,600	27,396	25,980	25,503	26,945	21,290	24,409
	Ground Water, Million Gallons	193.6	215.7	15.7	17.7	18.3	18.0	15.4	17.8	15.6	14.8	14.0	17.9	17.2	18.2	14.2	15.3	15.2
	Reuse Water, Million Gallons	276.8	254.5	14.7	2.4	13.9	19.4	22.1	19.8	22.9	30.3	36.7	1.1	0.0	15.1	52.4	50.7	6.4
	CWTS Influent, Million Gallons	106.5	219.5	Not Available	Not Available	Not Available	Not Available	Not Available	Not Available	Not Available	Not Available	18.1	18.3	16.9	16.5	16.5	11.1	9.2
	Perc Ponds to District II, Million Gal	46.3	48.2	Not Available	Not Available	Not Available	8.1	8.1	8.9	0.3	0.3	3.4	4.3	4.9	2.5	1.2	1.2	3.0
ASH PRODUCTION RATES																		
	Total Bed Ash, Tons, Units 1 and 2	312,400	195,439															
	Total Fly Ash, Tons, Units 1 and 2	179,700	153,623															
	Unit 2 Portion of Bed Ash, Tons	153,236	96,515															
	Unit 2 Portion of Fly Ash, Tons	88,145	75,865															
	Byproduct Sales, Tons	0	38,312															
FUEL COSTS (nominal) $/mmBTU																		
	GAS	6.23	6.66	4.82	4.81	5.49	6.14	7.80	7.15	6.06	6.55	6.61	5.82	5.75	5.41	5.41	5.13	6.89
	NS PETCOKE	0.71	0.91	0.41	0.47	0.49	0.85	0.55	0.97	0.30	0.73	0.71	0.97	0.60	0.73	0.70	0.70	0.71
	NS COAL	1.61	2.41	1.79	1.75	1.66	1.50	1.50	1.46	1.46	1.46	1.67	1.66	1.67	1.60	1.75	1.80	1.83
	NS LIMESTONE $/ton			10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125

Northside Unit 2 Operating Data
October 2002 thru December 2004

FILE: (0)JEADATA	DRAKE												
			Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
FUEL HEAT CONTENT														
NS-2 PETCOKE	HEAT CONTENT-BTU/LB		14,056	13,879	14,092	14,092	14,189	14,182	13,636	14,155	13,682	14,015	13,874	13,874
NS-2 COAL	HEAT CONTENT-BTU/LB		12,143	12,478	12,749	12,749	11,045	11,655	12,211	11,324	11,662	12,399	12,012	12,138
NS-2	PETCOKE	%S	3.75	3.91	4.04	4.04	3.67	5.36	4.45	4.94	6.14	3.82	6.14	4.03
NS-2	COAL	%S	2.93	3.23	2.98	2.98	2.77	2.64	2.71	0.62	3.01	2.68	2.26	2.66
NS-2	PETCOKE	%ash	0.17	0.91	0.92	0.92	0.53	0.24	0.45	0.76	1.00	1.43	0.93	0.27
NS-2	COAL	%ash	7.30	7.51	7.81	7.81	7.17	13.11	10.06	7.35	8.95	8.86	10.09	9.73
NS-2 OPER DATA	(GROSS CAP)	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5
	GROSS MWH GENERATED		197,874	54,281	71,595	0	141,806	87,405	167,506	209,458	196,519	158,750	470	173,687
	HOUSE LOAD MWH (ON-LINE)		14,360	4,381	5,991	0	10,113	7,305	9,609	14,151	14,333	10,831	16	10,834
	NET MWH (ON-LINE)		183,514	49,900	65,604	0	131,693	80,100	157,897	195,307	182,186	147,919	454	162,853
	GAS ON-LINE (KCF)		0	291	693	0	3,166	2,409	0	0	0	202	3,022	0
	PETCOKE ON-LINE (TONS)		27,092	12,565	16,129	0	32,971	7,829	39,467	53,336	52,289	39,700	305	44,731
	COAL ON-LINE (TONS)		39,350	5,357	7,981	0	11,653	25,811	15,391	14,239	15,843	10,386	322	13,270
	LIMESTONE		24,081	7,176	8,296	0	14,225	11,786	21,015	26,451	25,840	17,876	492	23,306
	HEAT CONTENT - GAS		1,055	1,050	1,049	1,050	1,056	1,049	1,054	1,054	1,052	1,052	1,053	1,048
	HEAT CONTENT - PETCOKE		14,056	13,879	14,092	14,092	14,189	14,182	13,636	14,155	13,682	14,015	13,874	13,874
	HEAT CONTENT - COAL		12,143	12,478	12,749	12,749	11,045	11,655	12,211	11,324	11,662	12,399	12,012	12,138
	HEAT RATE (O/L) (BTU/KWH, NET)		9,358	9,675	10,042	0	9,085	10,316	9,197	9,382	9,882	9,266	42,696	9,599
	ATTEMPTED STARTS		2	4	6	0	5	2	5	1	0	0	2	4
	STARTS		2	0	0	0	0	0	0	1	0	0	2	4
	HOURS ONLINE		714.02	227.15	308.03	0.00	508.83	383.08	604.00	725.83	720.00	623.62	6.13	628.93
	COMBUSTION HOURS		744.00	240.92	399.12	0.00	586.22	417.23	643.27	744.00	720.00	625.62	70.32	648.42
	MBTUs GAS		0	4,781	17,453	0	24,431	13,705	12,349	3,075	0	458	17,726	6,096
	MBTUs PETCOKE		761,612	356,304	460,809	0	940,229	223,116	1,087,371	1,511,364	1,430,880	1,113,215	12,376	1,250,950
	MBTUs COAL		955,650	136,580	206,275	0	258,681	604,522	379,744	322,809	369,503	257,642	11,315	324,690
	TOTAL MBTUs		1,717,262	497,665	684,659	0	1,223,612	841,498	1,479,545	1,837,247	1,800,383	1,371,323	41,417	1,581,860
	% GAS		0.00%	0.96%	2.55%	0.00%	2.00%	1.63%	0.83%	0.17%	0.00%	0.03%	42.80%	0.39%
	% PETCOKE		44.35%	71.60%	67.30%	0.00%	76.84%	26.51%	73.49%	82.26%	79.48%	81.18%	29.88%	79.08%
	% COAL		55.65%	27.44%	30.13%	0.00%	21.14%	71.84%	25.67%	17.57%	20.52%	18.79%	27.32%	20.53%
	LOAD FACTOR (GROSS)		93.2%	80.3%	78.1%	0.0%	93.7%	76.7%	93.2%	97.0%	91.7%	85.6%	25.8%	92.8%
	CAPACITY FACTOR (GROSS)		89.4%	26.2%	32.3%	0.0%	64.1%	40.8%	75.7%	94.6%	91.7%	71.7%	0.2%	78.5%
	MWHs GAS		0	412	1,472	0	2,463	1,190	1,250	312	0	46	0	598 0
	MWHs PETCOKE		81,227	32,143	40,703	-7,230	99,258	20,290	115,264	160,399	144,795	118,410	-4,975	128,450
	MWHs COAL		101,921	12,321	18,220	0	27,308	54,975	40,254	34,259	37,391	27,405	-1,921	33,340
	12 mth rolling CAP FACTOR		71.3%	67.7%	63.2%	0.0%	59.1%	54.5%	53.5%	56.7%	59.1%	58.9%	57.3%	55.8%
STACK EMISSIONS DATA - UNIT 2														
	SO2 Emissions, Tons		116.4	29.4	86.3	0.0	87.7	58.6	93.1	110.5	234.2	110.4	16.1	152.9
	SO2 Emissions, lb/MBtu		0.14	0.12	0.25	0.00	0.14	0.14	0.13	0.12	0.26	0.16	0.78	0.19
	NOx Emissions, Tons		69.8	26.5	29.5	0.0	46.6	29.9	55.0	68.6	55.7	41.5	4.0	65.5
	NOx Emissions, lb/Mbtu		0.08	0.11	0.09	0.00	0.08	0.07	0.07	0.07	0.06	0.06	0.19	0.08
	Particulate Matter, Tons		4.29	1.00	1.38	0.00	3.06	2.10	3.70	4.59	3.60	2.74	0.09	3.17
	Particulate Matter, lb/Mbtu		0.005	0.004	0.004	0.000	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004
	CO, Tons		61.6	10.5	41.1	0.0	30.7	39.1	46.5	17.3	7.8	6.4	8.4	21.2
	CO, lb/Mbtu		0.07	0.04	0.12	0.00	0.05	0.09	0.06	0.02	0.01	0.01	0.41	0.03
	CO, lb/hr		166	87	206	0	105	187	145	47	22	20	239	65
	VOC, Tons		2.46	0.42	1.64	0.00	1.23	1.57	1.86	0.69	0.31	0.26	0.34	0.85
	VOC, lb/Mbtu		0.003	0.002	0.005	0.000	0.002	0.004	0.003	0.001	0.000	0.000	0.016	0.001
	VOC, lb/hr		6.6	3.5	8.2	0.0	4.2	7.5	5.8	1.9	0.9	0.8	9.7	2.6
GADS DATA														
	Equivalent Availability Factor, EAF, %		94.73%	27.44%	38.55%	0.00%	68.12%	44.09%	79.41%	96.65%	94.53%	76.07%	0.43%	83.79%

FILE: (0)JEADATA DRAKE

	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
WATER AND WASTEWATER FLOWS (UNITS 1, 2, AND 3)												
Surface Water, Million Gallons	25,430	22,265	26,308	20,589	24,764	25,420	26,964	26,827	25,938	24,180	12,747	17,344
Ground Water, Million Gallons	20.9	19.8	20.8	19.6	25.0	21.1	21.4	11.9	13.7	14.4	12.4	14.6
Reuse Water, Million Gallons	0.0	0.0	0.0	12.5	27.4	15.6	26.3	39.5	34.0	35.6	31.7	31.9
CWTS Influent, Million Gallons	12.6	12.8	14.3	15.0	19.0	19.6	14.6	18.7	22.5	30.9	20.0	19.3
Perc Ponds to District II, Million Gal	1.9	2.8	2.4	1.3	2.2	4.3	5.5	4.2	5.8	6.1	5.8	6.0
ASH PRODUCTION RATES												
Total Bed Ash, Tons, Units 1 and 2												
Total Fly Ash, Tons, Units 1 and 2												
Unit 2 Portion of Bed Ash, Tons												
Unit 2 Portion of Fly Ash, Tons												
Byproduct Sales, Tons												
FUEL COSTS (nominal) $/mmBTU												
GAS	6.81	6.15	6.13	6.49	7.10	7.08	6.76	6.24	5.79	7.15	6.75	7.51
NS PETCOKE	0.74	0.70	0.75	0.81	0.74	0.69	0.80	1.04	1.05	1.09	1.19	1.37
NS COAL	1.86	2.09	2.36	2.37	2.37	2.37	2.38	2.40	2.66	2.70	2.66	2.70
NS LIMESTONE $/ton	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125

APPENDIX D - Capital Cost Data

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Summary by WBS
Unit 2 and 50% of Common

UNIT 2	DOE Phase	Task	WBS	Actual Costs
	1B - Design			
		Project Management and Support	2.1.11	**3,164,454**
		Permitting	2.1.12	**2,390,444**
		Preliminary Design	2.1.13	**2,175,695**
		Engineering/Detailed Design	2.1.14	**23,371,293**
		Unit 2 - Subtotal 1B Design		**$31,101,886**
	2 - Construction and Start-up			
		Project Management and Support	2.2.21	**5,826,510**
		Environmental Monitoring	2.2.22	**29,871**
		Boiler Equip/AQCS	2.2.23	**119,043,822**
		Balance of Plant Equipment	2.2.24	**35,070,257**
		Turbine/Generator Refurbishment & Upgrade	2.2.26	**15,588,735**
		Unit 2 - Subtotal Construction and Start-up		**$175,559,195**

COMMON	DOE Phase	Task	WBS	50% of Actual Costs
	1B - Design			
		Engineering/Detailed Design	3.1.14	**2,932,126**
		Common - Subtotal Engineering/Detail Design		**$2,932,126**
	2 - Construction and Start-up			
		Project Management and Support	3.2.21	**20,294,905**
		Environmental Monitoring	3.2.22	**115,751**
		Boiler Equip/AQCS	3.2.23	**9,141,358**
		Balance of Plant Equipment	3.2.24	**29,254,424**
		Fuel Handling Equipment	3.2.25	**52,992,980**
		Common - Subtotal Construction and Start-up		**$111,799,417**

TOTAL CAPITAL COST (Unit 2 Plus 50% of Common) **$321,392,624**

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

Unit 2

Unit 2	DOE Phase/Task	Work Package	Actual Costs
	1B - Design		
	Project Management and Support	PLANT MANAGEMENT	37,331
		ENGINEERING	845
		PROJECT MANAGEMENT	1,403,425
		I S MATERIAL	12,651
		LEGAL SERVICES	1,129,981
		FINANCE COSTS	499,676
		TRAVEL & TRAINING	80,545
			3,164,454
	Permitting	PERMITTING	189,857
		PERMITTING	2,200,587
			2,390,444
	Preliminary Design	PLANT MANAGEMENT	65,106
		ENGINEERING	124,447
		PRELIMINARY TESTING	227,972
		PLANT SERV. MTL & LABOR	10,835
		PRELIM. DESIGN	1,747,335
			2,175,695
	Engineering / Detail Design	STRUCT. & IMPVT`S	1,131,857
		JEA PROVIDED SERVICES	19,150
		BOILER PLANT EQUIP.	11,493,344
		PLANT MANAGEMENT	8,724
		ENGINEERING	74,480
		TURBOGENERATOR UNITS	1,810,971
	Engineering / Detail Design	ACCESSORY ELECT. EQUIP.	8,832,767
			23,371,293
	Unit 2 - Subtotal 1B Design		**$31,101,886**
	2 - Construction and Startup		
	Project Management and Support	PLANT MANAGEMENT	26,465
		PROJECT MANAGEMENT	174,078
		JEA PROVIDED SERVICES	19,874
		INSURANCE	3,479,225
		CONST. MGMT	2,099,238
		TRAVEL & TRAINING	27,630
			5,826,510
	Environmental Monitoring	ENVIRON. MON.	29,871
			29,871
	Boiler Equipment / AQCS	PLANT SERV. MTL & LABOR	2,404
		CONCRETE STACK	1,330,358
		AQCS	12,928,202
		ASH HANDLING SYSTEM	2,928,044

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

Unit 2

Unit 2	DOE Phase/Task	Work Package	Actual Costs
		C F B BOILER SUPPLY	47,112,999
		CFB BOILER ERECTION	13,612,635
		JEA PROVIDED SERVICES	95,348
		CSA	5,392,566
		BOP EQUIPMENT (FW)	10,516,441
		CONSTRUCTION INDIRECTS	15,194,347
		START-UP SUPPORT	1,990,845
		ELECTRICAL	5,176,185
		AUTOMATION & CONTROLS	2,763,448
			119,043,822
	Balance of Plant Equipment	PLANT SERV. MTL & LABOR	3,341
		FIRE PROTECTION	929,251
		CONTROL ROOM MOD.	399,372
		PAINTING	183,114
		BOILER FEED PUMPS	367,677
		CONDENSATE POLISHERS	1,476,989
		CYCLE CHEM FEED EQUIP	169,780
		DEAERATOR	800,365
		FEEDWATER HEATERS	1,025,372
		WATER SAMPLE RACK	32,091
		BULK INSULATION	609,114
		JEA PROVIDED SERVICES	21,992
		BFP FLUID DRIVE	1,166,221
		CIVIL ZCC #5032	216
		CSA	680,520
		EQUIP. INSPECTION	34,750
		SYSTEM TESTING	114,951
		CONSTRUCTION INDIRECTS	132,846
		EQUIPMENT RENTAL	653,109
		OTHER PROC. & CONST.	51,141
		CIRC. WATER PUMPS	2,072,940
		CC WATER HEAT EXCHANGER	19,207
		CONDENSATE PUMPS	15,197
		VACUUM PUMPS	146,046
		CONDENSER	2,761,842
		CONDENSER CLEANING SYS.	122,346
		BW PUMP MOTORS	4,423
		FILL PUMP	4,428
		GEN. SERVICE PUMPS	271,188
		PIPING & VALVES	7,249,577
		TRAVELING SCREENS	540,223
		VOID GROUTING	39,031
		COND. BOOSTER PUMPS	97,818
		COND. BSTR PUMP FLUID DRIVE	11,860
		CCW SURGE TANK & PIPING	570,744
		CIRC WATER PUMP STRUCT.	15,491
		NEW PUMP MTR. PROC. & INST	772,433
		MED. VOLT. SWITCHGEAR	621,466

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

Unit 2

Unit 2	DOE Phase/Task	Work Package	Actual Costs
		5 kV BUS DUCT REFURB.	31,247
		CATHODIC PROTECTION	470,104
		DCS	2,129,791
		LOW VOLTAGE SWITCHGEAR	556,629
		480V MCC & PWR PANEL REPL	470,525
		NON-SEG PHASE BUS DUCT	310,272
		PROTECTION CIRCUIT SYSTEM	5,272
		TRANSFORMERS	116,507
		BULK INSTR. & CONTROLS	371,798
		BATTERIES	10,596
		UNIT 1&2 ELECT. SEPARATION	190,486
		CTRL RM PANEL & INSTR. MODS	523,376
		RACEWAY & CONDUIT	3,037,166
		POWER & CONTROL CABLE	1,675,222
		MISCELLANEOUS ELECTRICAL	982,794
			35,070,257
	Turbine Generator Refurb./Upgrade	PLANT SERV. MTL & LABOR	1,931
		JEA PROVIDED SERVICES	97,974
		CONSTRUCTION INDIRECTS	167,074
		TURBINE	15,321,756
			15,588,735
	Unit 2 - Subtotal Construction and Startup		**$175,559,195**
	TOTAL CAPITAL COST (Unit 2)		**$206,661,081**

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

50% of Common

COMMON	DOE Phase/Task	Work Package	50% of Actual Costs
	1B - Design		
	Engineering / Detail Design	ENGINEERING	191,377
		STRUCT. & IMPVT`S	172,113
		BOILER PLANT EQUIP.	1,905,449
		TURBOGENERATOR UNITS	82
	Engineering / Detail Design	ACCESSORY ELECT. EQUIP.	663,107
			2,932,127
	Common - Subtotal Engineering/Detail Design		**$2,932,127**
	2 - Construction and Startup		
	Project Management and Support	PLANT MANAGEMENT	5,937
		CONST. MGMT	10,635,958
		INSURANCE	1,749,871
		PROJECT MANAGEMENT	299,202
		START-UP SUPPORT	7,549,330
		TRAVEL & TRAINING	54,609
			20,294,905
	Environmental Monitoring	ENVIRON. MON.	114,131
		ENVIRON. MON.	1,620
			115,751
	Boiler Equipment / AQCS	PLANT SERV. MTL & LABOR	933
		LIMESTONE PREP SYSTEM	6,535,510
		CFB BOILER ERECTION	442,793
		CSA	224,690
		CONSTRUCTION INDIRECTS	760,917
		ELECTRICAL	215,675
		MED. VOLT. SWITCHGEAR	307,524
		LOW VOLTAGE SWITCHGEAR	179,706
		480V MCC & PWR PANEL REPL	243,841
		NON-SEG PHASE BUS DUCT	139,056
		TRANSFORMERS	90,716
			9,141,358
	Balance of Plant Equipment	PLANT SERV. MTL & LABOR	24,068
		SPARE PARTS	45,021
		FIRE PROTECTION	37,277
		PAINTING	685
		AIR DRYER	2,823,353
		ASH HANDLING CONVEYORS	2,884,203
		ASH STG. & UNLOADING	3,717,055

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

50% of Common

COMMON	DOE Phase/Task	Work Package	50% of Actual Costs
		REUSE WATER TRT`MT SYS.	474,439
		HYPOCHLORITE PIPING & TKS.	80,008
		CIVIL ZCC #5032	4,621,165
		CSA	1,038,510
		CONSTRUCTION INDIRECTS	8,751,601
		EQUIPMENT RENTAL	1,091,349
		OTHER PROC. & CONST.	2,660,811
		CIRC. WATER PUMPS	4,217
		FUEL OIL TRF. PUMPS	82,870
		PIPING & VALVES	835,876
		MED. VOLT. SWITCHGEAR	123,172
		LOW VOLTAGE SWITCHGEAR	7,055
		480V MCC & PWR PANEL REPL	36,593
		TRANSFORMERS	76,144
		RACEWAY & CONDUIT	-521,146
		POWER & CONTROL CABLE	266,058
		MISCELLANEOUS ELECTRICAL	94,045
			29,254,424
	Fuel Handling Equipment	LAND PURCHASES	322,365
		SHIP UNLOADER	4,573,600
		UNLOADING DOCK	6,785,740
		FIRE PROTECTION	582,371
		MHS CONVEYORS	9,397,439
		JEA PROVIDED SERVICES	29,949
		FUEL STORAGE DOMES	4,929,191
		STACKER/RECLAIMER	2,846,066
		CSA	126,387
		MHS TRANSFER TOWERS	6,445,708
		CONSTRUCTION INDIRECTS	14,676,079
		OTHER PROC. & CONST.	291,123
		PIPING & VALVES	2,947
		MED. VOLT. SWITCHGEAR	556,775
		DCS	32,220
		RACEWAY & CONDUIT	32,748
		POWER & CONTROL CABLE	1,215,400
		MISCELLANEOUS ELECTRICAL	146,878
			52,992,980
	Common - Subtotal Construction and Startup		**$111,799,417**
	TOTAL CAPITAL COST (50% of Common)		**$114,731,543**

JEA NORTHSIDE REPOWERING PROJECT

Phase 1 Capital Improvement Projects

Unit 2 CFB Boiler and AQCS

ITEM #	Project Description	Actual Costs
1	Limestone Feed System Modifications to Improve Flow and Stabilize Feed Rate	96,102
2	Upgrade Limestone Transport to Design Capacity	1,311,310
3	Improve Reliability and Drying Capability of Limestone Preparation System	146,817
4	Modifications to Improve Silo Flow	40,998
5	Distributed Control System Initial Evaluation	32,653
6	Revamp Boiler AQCS Instrumentation for Accurate and Reliable Process Control	394,436
7	Perform Modifications to Air Quality Control System Process and Equipment to Improve Reliability of Recycle Mix Process and Slurry Pumping System	522,927
8	INTREX Tube Support Modifications and Ash Flow Modeling	380,483
9	Wind box Refractory Replacement and Damper Modifications	152,419
10	Replace Rear wall Drag Chain Slide Gates	144,512
11	Upgrade Booster Blower Bearings & Install Startup Burner Instruments	126,083
12	Evaluate, Modify, and Repair the Stripper Cooler Inlet and Cyclone Inlet Expansion Joints	781,457
13	Refractory Upgrade and Spray Water Nozzle Modifications to Stripper Coolers	234,554
14	Upgrade Fly Ash Valves and Bed Ash Blower Sole Plates	186,420
15	Replace Failed Critical Pipe Supports	399,930
16	Install Boiler Maintenance Hoist and Platforms	386,765
17	Construction Punchlist, Turnover Documentation	359,290
	Total Phase 1 Capital Improvements Projects	**$5,697,156**

JEA NORTHSIDE REPOWERING PROJECT

Phase 2 Capital Improvement Projects

Unit 2 CFB Boiler and AQCS

Item #	Project Description	Actual Costs
1	AQCS Process Improvements	721,545
2	Improve Reliability of Bed Ash and Fly Ash Valves	111,702
3	Above Bed Burners, INTREX Tubes and Furnace Grid Nozzle Replacement; also, Perform Interim INTREX Modifications to Mitigate Tube Failures.	3,513,713
4	DCS, BOP Projects, Black Belt Study, and Turnover Documentation	1,195,852
5	Modify Limestone Silo Outlet and Limestone Metering Equipment to Improve Flow Control and Stability	725,220
6	Enhancement to Ash Transport and Ash Processing Systems	870,106
	Total Phase 2 Capital Improvements Projects	**$7,138,138**

Fuel Capability Demonstration Test Report 2 for the JEA Large-Scale CFB Combustion Demonstration Project

50 / 50 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel

Submitted to
U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory (NETL)
Pittsburgh, Pennsylvania 15236
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1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels. Therefore, it was necessary for JEA to demonstrate this capability through a series of tests.

The purpose of the test program was to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility would be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin
    - Furan
- Stack opacity

This test report documents the results of JEA's Fuel Capability Demonstration Tests firing a 50/50 blend of Petroleum Coke and Pittsburgh 8 coal for the JEA Large-Scale CFB Combustion Demonstration Project. The term "blend" will be used throughout this report to describe the 50/50 blend of the two fuels. The tests were conducted in accordance with the Fuel Demonstration Test Protocol in Attachment A.

Throughout this report, unless otherwise indicated, the term "unit" refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

1.1 Test Schedule

Unit 2 of the JEA Northside plant site is a Circulating Fluidized Bed Steam Generator designed and constructed by Foster-Wheeler. The steam generator was designed to deliver main steam to the steam turbine at a flow rate of 1,993,591 lb/hr, at a throttle pressure of 2,500 psig, and at a throttle temperature of 1,000 deg F when firing Pittsburgh 8 coal.

The fuel capability demonstration test for the unit firing the blended coal was conducted over a five (5) day period beginning on January 27, 2004 and completed on January 31, 2004. During that five (5) day period, data were taken in accordance with the Test Protocol (Attachment A) while the unit was operating at 100% load, 80% load , 60% load, and 40% load.

The following log represents the sequence of testing:

- Day 1 January 27, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 1135 hours; completed at 2026 hours.
  - Boiler performance testing commenced at 1130 hours; completed at 1530 hours.

- Day 2 January 28, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 1000 hours; completed at 1604 hours.
  - Boiler performance testing commenced at 1000 hours.
  - The A1 fuel feeder went off-line at approximately 1230 hours. A1 fuel feeder back on line at approximately 1430 hours. The unit was allowed to stabilize. The test continued at 1600 hours. The test was completed at 1800 hours.

- Day 3 January 29, 2004:
  - Unit at 80% load - turbine load set and maintained at approx. 240 MW.
  - Unit began 2-hour stabilization period at 240 MW at 1315 hours.
  - Boiler performance testing commenced at 1500 hours after stabilization period completed; test completed at 1900 hours.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 3 (cont'd) January 29, 2004:
  - Unit load 60% load after completion of testing at 80% load - turbine load set and maintained at approx. 180 MW.
  - Unit began 2-hour stabilization period at 180 MW at 2000 hours.
  - Boiler performance testing commenced at 2200 hours after stabilization period completed; test completed at 0200 hours, Jan. 30, 2004.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 4 January 30, 2004:
  - Unit load decreased to 40% load - turbine load set and maintained at approx. 120 MW.
  - Unit began 2-hour stabilization period at 120 MW at 1200 hours.
  - DCS failure tripped unit at approximately 1700 hours - 40% load test postponed until January 31, 2004.

- Day 5 January 31, 2004:
  - Unit load set at 40% - began stabilization period at 0700 hours.
  - Boiler performance testing began at 0900 hours after stabilization period completed; test completed at 1300 hours.
  - Flue gas emissions data taken and recorded by CEMS system.
  - This concluded the testing of JEA Northside Unit 2 firing the 50/50 blended coal.

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of “as-fired” fuel
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Fahrenheit
FA	Fly ash
FF	Fabric Filter
gpm	gallons per minute
gr/acf	grains per actual cubic foot

Abbreviation	Definition
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater
$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside
Pb	Lead

Abbreviation	Definition
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1
W_{fe}	Fuel feed rate (lb/hr)

Abbreviation	Definition
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number

2.0 SUMMARY OF TEST RESULTS

2.1 Test Requirements

The Protocol required that the following tests be performed and the results be reported at four (4) different unit loads:

- Unit Capacity, per cent (all capacities in Megawatts are gross MW).
- Boiler Efficiency, per cent (100 % load only).
- Main Steam and Reheat Steam Temperature, deg F.
- Emissions (NOx, SO2, CO, and Particulate (see Section 4.0 of this report).

No design performance data for the boiler firing the blended fuel were provided by Foster-Wheeler. For the purposes of this report, the results of the test were compared against the design performance data of the boiler produced by Foster-Wheeler, as follows:

Boiler efficiency (firing Pittsburgh 8 coal):	88.1 % HHV
Boiler efficiency (firing Pet Coke):	90.0 % HHV
Main steam flow at turbine inlet:	1,993,591 lb/hr
Main steam temperature at turbine inlet:	1,000 deg F
Main steam pressure at turbine inlet:	2,500 psig
Hot reheat steam temperature at turbine inlet:	1,000 deg F

The average steam temperatures during the Test were compared with the limits described in the following sections (The average of the readings recorded every minute shall be determined to be the Test average):

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

2.2 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the ‘closed’ position of certain main steam and feedwater system valves. A listing of these valves is included in Attachment F.

2.3 Test Results

The results of the 100% tests are summarized in Table 1. The results of the part-load tests are summarized in Table 2. The performance of the boiler met and/or exceeded all of the design values provided by Foster-Wheeler. Two and a half hours into the 80% MCR test, the A1 feeder tripped. The problem was fixed, the feeder was put back on line, and the unit was ramped back up to 80% load. The testing commenced at approximately 1600 hours after the unit was allowed

to stabilize - no further equipment problems were observed or recorded. No further problems with the fuel feeding system were observed or recorded during the remainder of the part-load testing periods.

TABLE 1 - TESTS RESULTS - 100% LOAD

	Design Maximum-Continuous Rating (MCR)	January 27, 2004 Test (**corrected to MCR, see Note 4)	January 28, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.6 **(Note 1)	91.7 **(Note 1)
Capacity Calculation (percent)	NA	95.3	95.4
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,848,031**	1,846,341**
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	1,002**	1,001**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,776,860	1,776,167
Pressure (psig)	547.7	569.1	565.4
Temperature (°F)	1,000	1,007**	1,008**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,775,434	1,774,004
Pressure (psig)	608.6	568.4	564.9
Enthalpy (Btu/lb)	1,304.5	1,295.25	1,292.91
Feedwater to Economizer			
Temperature (°F)	487.5	484.3	483.5
50/50 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	74.45	73.68
Hydrogen %	4.1	4.4	4.6
Sulfur %	5.0	5.34	5.86
Nitrogen %	1.15	1.47	1.63
Chlorine %	0.05	0.09	0.11
Oxygen %	2.20	1.25	1.26
Ash %	6.6	5.75	5.91
Moisture %	7.1	7.34	7.05
HHV (Btu/lb)	13,345	13,429	13,251
Fuel Flow Rate (lb/hr)	NA	194,172	195,177
Limestone Composition (% By Weight)			
$CaCO_3$	92.0	91.4	86.4
$MgCO_3$	3.0	2.95	2.82

	Design Maximum-Continuous Rating (MCR)	January 27, 2004 Test (**corrected to MCR, see Note 4)	January 28, 2004 Test (**corrected to MCR, see Note 4)
Inerts	4.0	5.15	10.43
Total Moisture	1.0	0.51	0.36
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	46.77	47.03
MgO and inerts	15.0	53.23	52.97
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	66,434	73,001
Flue Gas Emissions			
Nitrogen Oxides, NOx, lb/MMBtu (HHV)	0.09	0.07	0.07
Uncontrolled SO2, lb/MMBtu (HHV) - based on 50/50 blend	7.49	7.95	8.845
Boiler Outlet SO2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2026	0.2771
Stack SO2 lb/MMBtu, (HHV)	0.15	0.093	0.11
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0041	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.015	0.016
Opacity, percent	10	1.01	1.80
Ammonia (NH3) Slip, ppmvd	2.0	0.325	
Ammonia feed rate, gal/hr	NA	3.73	6.26
Lead, lb/MMBtu	2.60×10^{-5} (max)	8.22×10^{-7}	
Mercury (fuel and limestone), µg/g	NA	3.02×10^{-7}	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 8.532 (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	Not Utilized	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	1.69×10^{-5}	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from Foster-Wheeler data).
NOTE 2: Refer to Section 4.3.4.1.
NOTE 3: Design boiler outlet SO2 emission rate based on 85% removal of SO2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of Attachment A, FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.

TABLE 2 - BOILER & SDA SO2 REMOVAL EFFICIENCY

	Design Basis	January 27, 2004 Test	January 28, 2004 Test
Percent of total SO2 removed by boiler	85.0 typical, with range of 75 - 90	97.5	96.8
Percent of total SO2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.3	1.9
Percent of Total SO2 Removed	97.1	98.8	98.7
Percent of SO2 entering SDA removed in SDA	81.0 typical with range 90 – 71	54	60.3
Boiler Calcium to Sulfur Ratio	< 2.88	1.7	2.25

TABLE 3 - TEST RESULTS - PARTIAL LOADS

	Day 3	Day 4	Day 5
Unit Capacity (MW)	240	180	120
Percent MCR Load	80%	60%	40%
Capacity Calculation (percent)	76.6	58.0	38.2
Total Main Steam Flow, lb/hr	1,442,226	1,049,633	715,464
Main Steam Temperature, deg F	1,004	993	997
Main Steam Pressure, psig	2,340	1,701	1,062
Cold Reheat Steam Temperature, deg F	577.5	558.02	573.64
Hot Reheat Steam Temperature, deg F	1,006	1,011	999
NOx, lb/MMBtu	0.04	0.043	0.033
CO, lb/MMBtu	0.024	0.0276	0.08
SO2, lb/MMBtu	0.08	0.067	0.109
Opacity, percent	1.4	1.1	0.8

2.3.1 Unit Capacity - During the five (5) day testing period, the boiler was successfully operated at a turbine load of approximately 300 MW, for day 1 and day 2, and at partial turbine loads of approximately 240 MW, 180 MW, and 120 MW, for day 3, day 4, and day 5. The unit operated steadily at each of the stated loads without any deviation in unit output. Prior to each of the testing periods, the unit was brought to load and allowed to stabilize for two (2) hours prior to the start of each test.

2.3.2 Boiler Efficiency - The steam generator operated at corrected efficiencies of 91.6 % and 91.7% on Day 1 and Day 2, respectively, of the testing period. These efficiencies exceeded the design values for firing coal by approximately 3.5 %, and by approximately 1.6% for firing pet coke.

2.3.3 Steam Temperature - During both days at 100% load operation, the average corrected main steam temperature measured at the turbine inlet was 1,001 deg F, which is within the design tolerances of the unit. Additionally, the corrected hot reheat steam temperature measured at the turbine inlet was 1,018 deg F, which is also within the design tolerances of the unit. During partial load operation, the main steam temperatures and the hot reheat temperatures were within the design tolerances previously listed in Section 2.1.

2.3.4 Steam Production - The steam flows of the unit at the 100% load operation cases and partial load operation cases were each determined by adding the main steam desuperheating system flow rates to the feed water system flow rates, and subtracting the continuous blow down flow rates and the sootblowing steam flow rates. The data for each of these systems were retrieved from the plant information system database. The main steam flow rates were corrected for deviations from the design MCR feedwater temperature. Although the corrected main steam flow rates determined for the 100% load operation cases were less than the design flow rates established by Foster-Wheeler, the main steam flow rates were adequate to maintain the steam turbine at the desired plant output. The main steam flow rates at the partial load operation cases were adequate to maintain the steam turbine at the required output.

2.3.5 Calcium to Sulfur Ratio (Ca:S) - The calcium to sulfur ratio represents the ability of the CFB boiler and limestone feed system to effectively remove the sulfur dioxide produced by the combustion process of the boiler. The maximum ratio established for firing the blended coal was 2.88. The calculated calcium to sulfur ratios for Day 1 and Day 2 are approximately 1.7 and 2.25, respectively. These values represent SO2 removal efficiencies for the boiler of greater than 95 % which are acceptable values for a CFB. SO2 reductions of greater than 90% are typically achieved in a CFB with Ca:S ratios of 2 to 2.5. These values are dependent on the sulfur content in the fuel and the reactivity of the limestone.

3.0 BOILER EFFICIENCY TESTS

The unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in Section 2 of the Attachment A Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency. No significant operational restrictions were observed during testing at the 100% MCR condition.

3.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcinations / sulfation. A complete description of the modified procedures is included in Section 4.2 of Attachment A. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the fly ash, and the heat loss due to radiation and convection from the insulated boiler surfaces. A complete list of the heat losses can be found in Section 4.2.1 of Attachment A. The completed efficiency calculations are included in Attachment F to this report.

3.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. The data provided by the plant instrumentation is included in *Attachment D, PI Data Summary*. Additional data required for the boiler efficiency calculations were provided by two independent testing contractors, PGT/ESC, and Clean Air Engineering (CAE). A summary of this information is located in *Attachments G, H, I, J, and K, lab analyses provided by PGT/ESC for the fuel, limestone, bed ash, fly ash, and environmental data,* and *Attachment C, CAE Test Report,* respectively. As directed in the test protocol (Attachment A), test data for days 1 and 2 were taken and labeled by CAE and PGT. No flue gas sampling was performed on the unit during operations at reduced loads. Data were, however, recorded by the CEMS system and are reported in this document.

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the plant information system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, fly ash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis. (Refer to Figures 1 thru 6 for approximate locations).

<u>Lime (Figure 1):</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Fly Ash (Figures 2, 3, and 4):</u>

Fly Ash samples were taken by two different methods.

1) Fly ash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Fly ash was also taken by grab sample method in two different locations. One grab sample was taken ever hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel (Figures 4, 5, and 6):</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

<u>Limestone (Figures 4 and 6):</u>

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

<u>Bed Ash (Figure 6):</u>

Bed Ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

As instructed by the Test Protocol, all of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation. The results of the lab analyses are included in Attachments G, H, I, and J.

4.0 AQCS INLET AND STACK TESTS

4.1 System Description

The Unit 2 AQCS consists of a single, lime-based spray dryer absorber (SDA) and a multi-compartment pulse jet fabric filter (PJFF). The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [Ca(OH)2] slurry, which is fed to the atomizers as a supplemental reagent.

4.2 Unit Emissions Design Points

The following sections describe the desired emissions design goals of the unit. The tests were conducted in accordance with standard emissions testing practices and test methods as listed in Section 4.2.7. It should be noted that not all tests conducted fit exactly the 4 hour performance test period that was the basis of the fuel capability demonstration test. Several of the tests (especially those not based on CEMS) had durations that were different than the 4 hour performance period due to the requirements of the testing method and good engineering/testing practice. All sampling tests were done at the 100% load case only. All data at the 100%, 80%, 60% and 40% performance load tests were collected by the CEMS.

4.3 Emission Design Limits and Results

4.3.1 NOx / SO2 / Particulate Emission Design Limits / Results

The following gaseous emissions were measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NOx) values in the flue gas as measured in the stack were expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMBtu values reported by the Continuous Emissions Monitoring system (CEMS) were used as the measure of NOx in the flue gas over the course of each fuel test. The average NOx values for Day 1 and Day 2, based on HHV, were 0.07 lb/MMBtu and 0.07 lb/MMBtu, respectively. Both of these values were less than the expected maximum value.

b. **Sulfur dioxide** (SO2) The design operating condition of the unit is to remove 85 percent of the SO2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. Burning performance coal with a boiler SO2 removal efficiency of 85%, the SO2 concentration at the air heater outlet was expected to be 1.12 lb/MMBtu, with an uncontrolled SO2 emission rate (at 0% SO2 removal) calculated to be 7.49 lb/MMBtu. JEA has chosen to operate at a much higher boiler SO2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods

with excess SO2 emissions. Over time the operations group has learned that if limestone feed is higher than normally desired the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO2 removal and increased SDA removal.

The SO2 concentration at the SDA inlet was measured by an independent test contractor, Clean Air Engineering (CAE). These results are included in Attachment C. The average SO2 values for Day 1 and Day 2, based on HHV of the fuel, out of the air heaters and into the SDA, were 0.093 lb/MMBtu and 0.11 lb/MMBtu, respectively. Both of these values were below the expected outlet emission rate. In fact, the boiler removed 98.8% and 98.7% respectively, in comparison to the design removal rate of 85%. Uncontrolled SO2 emissions rates were calculated to be 7.95 lb/MMBtu and 8.845 lb/MMBtu, respectively, for an increased SO2 input of 6.1% and 18.1% above the design performance coal SO2 input of 7.49 lb/MMBtu.

The SO2 emissions from the stack during the execution of the tests were expected to be less than 0.15 lb/MMBtu. The hourly average lb/MMBtu values (based on HHV of the fuel) reported by CEMS were used as the measure of SO2 emissions from the stack for the test. The average SO2 values for Day 1 and Day 2, (based on HHV of the fuel) were 0.102 lb/MMBtu and 0.106 lb/MMBtu, respectively. These values were 32% and 29% lower than the 0.15 lb/MMBtu permitted emission rate.

b. **Solid particulate matter** in the flue gas at the fabric filter outlet was expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input. These values were measured at the stack by CAE. The average particulate matter value for the testing period was 0.004 lb/MMBtu which is below the expected maximum value.

4.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas was expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by the plant CEMS. The average values for Day 1 and Day 2 were 0.015 lb/MMBtu and 0.016 lb/MMBtu, respectively. The average values were less than the maximum expected value.

4.3.3 SO3 Emissions Design Point

Sulfur Trioxide (SO3) in the flue gas was assumed to be zero due to the high removal efficiency of the SDA. No testing was done for SO3 as explained in the Test Protocol located in Attachment A. See Section 4.2.3 of the Fuel Capability Test Protocol for the rationale.

4.3.4 NH3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH3, Lead, Mercury, and Fluorine gaseous emissions were measured during the Test (EPA Permit averaging period). Mercury sampling and analysis was performed at the inlet to the AQCS system in addition to the samples taken at the stack. Both samples were taken by CAE. Lead, ammonia and Fluorine were sampled only at the stack by CAE. The average values are indicated in Table 1.

4.3.4.1 Mercury Testing Anomaly

During the emissions tests, the reagent used in the fourth impinger of the Ontario Hydro sampling train was a 5% HNO3 (nitric acid) / 10% H2O2 (hydrogen peroxide) solution. Mercury levels in both the 5% / 10% reagent blank and the 5% / 10% portion of the field train blanks were elevated. The mercury concentration in the reagent field blanks of the other solutions (KCI, potassium chloride, and KMnO4, potassium permanganate) used in the Ontario Hydro sampling train was at the expected levels or below the detection limit. In accordance with the Ontario Hydro Method, the allowable blank adjustments have been made to the final results presented.

A review of the total mercury in the coal was completed for comparison to measured values. The coal analyses indicated a mercury content of approximately 0.003 µg/g, with a limestone mercury content of 0.03 µg/g. This is equivalent to a total mercury content of 0.0007 lb/hr. This represents more mercury than what was measured by the independent test contractor at the inlet to the SDA. However due to the bias adjustment made by the independent test contractor, the removal efficiency was lower than expected. Subsequent tests should help determine the expected mercury removal efficiency of the unit.

4.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions testing were not required for evaluation of the blended coal.

4.3.6 Opacity

The opacity was measured by the plant CEMS/COMS (Continuous Opacity Monitoring System) to determine the opacity of the unit over a six minute block average during the test period. The maximum expected opacity was 10%. The testing indicated that the maximum opacity of the unit during the two day test was 1.8%, which is much less than the maximum opacity value.

4.4 Flue Gas Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – CTM 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans – PCDD/F

Specific descriptions of the testing methods (non-CEMS) are included in the Clean Air Engineering Emissions Test Report located in Attachment D of this document.

4.5 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration and as listed in Section 4.2.7. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NOX, SO2, and CO2 analyzers. The data listed for CEMS in Section 4.2.7 originated from the certified Data Acquisition Handling System (DAHS).

Attachments

Attachment A - Fuel Capability Demonstration Test Protocol

Attachment B - Boiler Efficiency Calculation

Attachment C - CAE Test Report

Attachment D - PI Data Summary

Attachment E - Abbreviation List

Attachment F - Isolation Valve List

Attachment G - Fuel Analyses - 50/50 Blend Pet Coke and Pittsburgh 8 Coal

Attachment H - Limestone Analyses

Attachment I - Bed Ash Analyses

Attachment J - Fly Ash (Air Heater and PJFF) Analyses

Attachment K - Ambient Data, Jan. 27, 2004 and Jan. 28, 2004

Attachment L - Ambient Temperatures, Jan. 29, 2004, Jan. 30, 2004, and Jan. 31, 2004

ATTACHMENT A

Fuel Capability Demonstration Test Protocol

This Document is located via the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

ATTACHMENT B

Boiler Efficiency Calculation

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	194,172	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7445	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0440	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0125	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0147	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0534	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0575	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0734	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	13,429	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	66,434	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9140	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0295	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0515	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0051	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.8462		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	0	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0003	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0003	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2113	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	42,543	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0169	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0169	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2096	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	30,492	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	108	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	53	LB/HR	
1.5.4	Fan Outlet Temperature, °F	108	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	755,011	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	110	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	35,790	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	166	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	44706	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	178	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)
Test Date:	January 27, 2004
Test Start Time:	11:30 AM
Test End Time:	3:30 PM
Test Duration, hours:	4

Boiler Efficiency: 91.64

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	64.24	°F	ta
1.6.2	Ambient wet bulb temperature, °F	57.96	°F	tawb
1.6.3	Barometric pressure, inches Hg	29.99	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0087	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	304.70	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates)
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	574.12	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0027	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	1533.2	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	484.3	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,828,819	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	2,561.5	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.7	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,700.6	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	303.0	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	19,086	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.7	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	1,003.5	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,847,905	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	713.66	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	300.87	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	1,426	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	568.42	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	604.01	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	569.12	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,007.48	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,775,313	LB/HR	RHin - From turbine heat.

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1	Average Air Heater Inlet Temperature	109.29	

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	182,495	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0295	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9705		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1	**Accumulation of Bed Inventory**	0	lb/h
4.2	**Corrected Ash Carbon Content**		
4.2.1	Bottom Ash, fraction	0.0003	lb/lb BA
4.2.2	Fly Ash, fraction	0.0169	lb/lb FA
4.3	**Bottom Ash Flow Rate**		
4.3.1	Total bottom ash including bed change	42,543.0267140	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.9940	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.933458109	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	66434	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.993961966	mole Ca/mole S	
	LImestone Flow Rate from PI Data, lb/h	**66,434**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-1.65859E-05	percent	
4.4.6	Calculated Fly Ash Flow Rate	30,492	lb/h	
4.4.7	Difference Calculated vs Measured	0.0000582144	percent	
4.5	**Total Dry Refuse**			
4.5.1	Total Dry Refuse Hourly Flow Rate	73,035	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.4002	lb/lb AF fuel	
4.6	**Heating Value Of Total Dry Refuse**			
4.6.1	Average Carbon Content Of Ash	0.0072	fraction	
4.6.2	Heating Value Of Dry Refuse	104.84	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1	**Carbon Burned Adjusted For Limestone**		
5.1.1	Carbon Burned	0.7416	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7767	lb/lb AF fuel

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	27.984	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3786	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.9007	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.8459	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6398	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	10.1116	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0147	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0734	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3931	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0019	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.1143	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.6151	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6442	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	14.1977	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7873	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.5543	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0111	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.8166	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1180	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	0.00085028	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1455		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8095		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.5672	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6385	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.5668	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01032	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.1946	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.3330	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1100	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7853	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	14.1498	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7794	lb/lb mole	

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0470	fraction
5.2.19.2	Nitrogen, fraction weight	0.7440	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2090	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.489	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.8459	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4853	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.5984	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0147	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0734	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3931	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0019	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.1085	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.9474	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7361	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.5242	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8375	lb/lb AF fuel
		Volume Basis	
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	% Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.3508	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	80.9131	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1245	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	0.000304142	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1535	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8078	
5.3.12	Weight Dry FG At Air Heater INLET	12.9405	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8291	lb/lb mole

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

		Volume Basis % Wet Flue Gas	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.3.14.1	Carbon Dioxide, volume percent	14.2664	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01085	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3457	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.1972	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1157	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	7.0641	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.5173	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9210	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0374	fraction
5.3.17.2	Nitrogen, fraction weight	0.7379	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2191	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0056	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0358	fraction
5.3.18.2	Nitrogen, fraction weight	0.7064	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2098	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0054	fraction
5.3.18.6	Moisture, fraction weight	0.0425	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.367	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.8459	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5299	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.7468	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0147	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0734	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3931	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0019	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.1102	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	13.1404	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7085	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	13.7189	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.8225	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas		
5.4.7.1 a	Carbon Dioxide, volume percent	14.0568	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.2379	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1140	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.9806	percent volume
		100.0000	percent volume

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
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Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.1117	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8702	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	80.8841	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1225	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-2.24399E-05	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-2.65237E-09	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

	Oxygen
C0	-1.1891960E+02
C1	4.2295190E-01
C2	-1.6897910E-04
C3	3.7071740E-07
C4	-2.7439490E-10
C5	7.384742E-14

5.5.2 a	Flue Gas Constituent Enthalpy At tG15	5.070631E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8	7.095556E+00

	Nitrogen
C0	-1.3472300E+02
C1	4.6872240E-01
C2	-8.8993190E-05
C3	1.1982390E-07
C4	-3.7714980E-11
C5	-3.5026400E-16

5.5.2 b	Flue Gas Constituent Enthalpy At tG15	5.6222912E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8	7.9570436E+00

	Carbon Dioxide
C0	-8.5316190E+01
C1	1.9512780E-01
C2	3.5498060E-04
C3	-1.7900110E-07
C4	4.0682850E-11
C5	1.0285430E-17

5.5.2 c	Flue Gas Constituent Enthalpy At tG15	4.9179481E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8	6.5873912E+00

	Carbon Monoxide
C0	-1.3574040E+02
C1	4.7377220E-01
C2	-1.0337790E-04
C3	1.5716920E-07
C4	-6.4869650E-11
C5	6.1175980E-15

5.5.2 d	Flue Gas Constituent Enthalpy At tG15	5.6822088E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8	8.0274306E+00

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.5811376E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	4.8434473E+00		

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	54.49	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	7.63	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	635.78	Btu/lb AF fuel	
5.6 HHV Percent Loss, as tested		4.73	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1197.78	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * $(tG15)^2$ + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	77.29	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	82.20	Btu/lb AF fuel	
6.4 HHV Percent Loss, as tested		0.61	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	440.48	Btu/lb AF fuel
7.2 HHV Percent Loss, as tested		3.28	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	41.96	Btu/lb AF fuel
8.2 HHV Percent Loss, as tested		0.31	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	-6.37	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	6.53	Btu/lb AF fuel
9.2 Total Dry Refuse Heat Loss, as tested		0.16	Btu/lb AF fuel
9.3 HHV Percent Loss, as tested		0.00	percent

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.64**
Test Date:	January 27, 2004		
Test Start Time:	11:30 AM		
Test End Time:	3:30 PM		
Test Duration, hours:	4		

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.48	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	151.08	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	53.62	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	11.41	Btu/lb
10.3 HHV Percent Loss, as tested		0.08	percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	221.58	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	2.08	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-349.25	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-125.59	Btu/lb AF Fuel
11.5 HHV Percent Loss		-0.94	percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss		0.27	percent
12.1.1	Radiation & Convection Heat Loss	36.78	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	635.78
13.1.2	82.20
13.1.3	440.48
13.1.4	41.96
13.1.5	0.16
13.1.6	11.41
13.1.7	-125.59
13.1.8	36.78
	1,123.18

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Unit Tested:	**Northside Unit 2 - Test #2 (50/50 Blend)**	**Boiler Efficiency:**	**91.64**
Test Date:	**January 27, 2004**		
Test Start Time:	**11:30 AM**		
Test End Time:	**3:30 PM**		
Test Duration, hours:	**4**		

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.73
13.1.10	Moisture In Fuel	0.61
13.1.11	H2O From H2 In Fuel	3.28
13.1.12	Unburned Combustibles In Refuse	0.31
13.1.13	Dry Refuse	0.00
13.1.14	Moisture In Combustion Air	0.08
13.1.15	Calcination/Sulfation	-0.94
13.1.16	Radiation & Convection	0.27
		8.36
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***91.64***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.42	Btu/lb
14.1.2	Blow Down, Btu/lb	738.40	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	277.56	Btu/lb
14.1.5	Main Steam, Btu/lb	1463.44	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	271.71	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1293.94	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1521.20	Btu/lb
14.2 Heat Output		2,245,760,604	Btu/h
		2,247,546,274	

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,450,735,926	Btu/h
15.1.2	Fuel Burned - CALCULATED	182,496	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-0.000699774	percent

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Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.74**
Test Date:	January 28, 2004		
Test Start Time:	10:00 AM		
Test End Time:	4:00 PM		
Test Duration, hours:	4		

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	195,177	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7368	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0460	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0126	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0163	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0586	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0591	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0705	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	13,251	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	73,001	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.8639	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0282	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.1043	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0036	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.7909		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	0	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0001	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0001	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2119	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	54,570	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0167	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0167	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2107	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	27,159	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	96	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	54	LB/HR	
1.5.4	Fan Outlet Temperature, °F	96	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	755,011	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	95	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	35,984	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	150	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	45158	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	162	°F	tspb

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1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	39.96	°F	ta
1.6.2	Ambient wet bulb temperature, °F	43.19	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.34	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0065	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	293.84	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates)
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	570.21	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0052	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	1501.9	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	483.5	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,823,519	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	2,562.0	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.7	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,699.7	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	295.1	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	22,822	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.9	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	1,002.7	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,846,341	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	708.45	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	316.17	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	2,164	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	564.91	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	599.83	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	565.43	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,008.17	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,774,004	LB/HR	RHin - From turbine heat.

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CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1	Average Air Heater Inlet Temperature	96.32	

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	185,198	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0269	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9731		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1	**Accumulation of Bed Inventory**	0	lb/h
4.2	**Corrected Ash Carbon Content**		
4.2.1	Bottom Ash, fraction	0.0001	lb/lb BA
4.2.2	Fly Ash, fraction	0.0167	lb/lb FA
4.3	**Bottom Ash Flow Rate**		
4.3.1	Total bottom ash including bed change	54,570.4521370	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.8606	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.96324464	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	73001	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.860570872	mole Ca/mole S	
	LImestone Flow Rate from PI Data, lb/h	**73,001**		
4.4.5	Difference Estimated vs Assumed - Ca:S	9.12915E-06	percent	
4.4.6	Calculated Fly Ash Flow Rate	27,159	lb/h	
4.4.7	Difference Calculated vs Measured	0.0000000026	percent	
4.5	**Total Dry Refuse**			
4.5.1	Total Dry Refuse Hourly Flow Rate	81,729	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.4413	lb/lb AF fuel	
4.6	**Heating Value Of Total Dry Refuse**			
4.6.1	Average Carbon Content Of Ash	0.0056	fraction	
4.6.2	Heating Value Of Dry Refuse	81.44	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1	**Carbon Burned Adjusted For Limestone**		
5.1.1	Carbon Burned	0.7343	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7679	lb/lb AF fuel

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Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	28.056	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3817	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.9110	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.8135	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6397	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	10.1305	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0163	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0705	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.4114	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.0851	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.6032	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6180	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	14.1717	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7822	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.3889	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0111	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.9689	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1311	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	0.000647346	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1439		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8111		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.5512	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6147	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.4347	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01033	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.2015	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.5993	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1224	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.6317	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	14.1197	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7763	lb/lb mole	

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5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0470	fraction
5.2.19.2	Nitrogen, fraction weight	0.7461	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2069	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.569	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.8135	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4852	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.6173	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0163	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0705	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.4114	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.0808	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.9355	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7084	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.4997	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8301	lb/lb AF fuel

		Volume Basis % Dry Flue Gas	
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas		
5.3.7.1	Carbon Dioxide, volume percent	15.1763	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.0737	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1383	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	0.000655001	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1518	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8071	
5.3.12	Weight Dry FG At Air Heater INLET	12.9631	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8923	lb/lb mole

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		Volume Basis % Wet Flue Gas	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.3.14.1	Carbon Dioxide, volume percent	14.1261	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01086	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3509	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.4633	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1287	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.9201	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.5273	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9981	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7357	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2163	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0108	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0357	fraction
5.3.18.2	Nitrogen, fraction weight	0.7050	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2072	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0103	fraction
5.3.18.6	Moisture, fraction weight	0.0416	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.402	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.8135	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5289	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.7623	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0163	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0705	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.4114	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.0820	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	13.1242	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.6819	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	13.6896	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.8160	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas		
5.4.7.1 a	Carbon Dioxide, volume percent	13.9236	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.5031	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1269	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.8357	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.74**
Test Date:	January 28, 2004		
Test Start Time:	10:00 AM		
Test End Time:	4:00 PM		
Test Duration, hours:	4		

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	14.9452	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8641	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.0430	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1362	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-4.148E-06	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	0.000940575	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

	Oxygen
C0	-1.1891960E+02
C1	4.2295190E-01
C2	-1.6897910E-04
C3	3.7071740E-07
C4	-2.7439490E-10
C5	7.384742E-14

5.5.2 a	Flue Gas Constituent Enthalpy At tG15	4.824907E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8	4.242769E+00

	Nitrogen
C0	-1.3472300E+02
C1	4.6872240E-01
C2	-8.8993190E-05
C3	1.1982390E-07
C4	-3.7714980E-11
C5	-3.5026400E-16

5.5.2 b	Flue Gas Constituent Enthalpy At tG15	5.3532667E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8	4.7612480E+00

	Carbon Dioxide
C0	-8.5316190E+01
C1	1.9512780E-01
C2	3.5498060E-04
C3	-1.7900110E-07
C4	4.0682850E-11
C5	1.0285430E-17

5.5.2 c	Flue Gas Constituent Enthalpy At tG15	4.6700315E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8	3.9252409E+00

	Carbon Monoxide
C0	-1.3574040E+02
C1	4.7377220E-01
C2	-1.0337790E-04
C3	1.5716920E-07
C4	-6.4869650E-11
C5	6.1175980E-15

5.5.2 d	Flue Gas Constituent Enthalpy At tG15	5.4097371E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8	4.8028593E+00

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.74**
Test Date:	January 28, 2004		
Test Start Time:	10:00 AM		
Test End Time:	4:00 PM		
Test Duration, hours:	4		

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.4021227E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	2.8883721E+00		

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	51.87	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	4.56	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	641.07	Btu/lb AF fuel	
5.6 HHV Percent Loss, as tested		4.84	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1192.82	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * $(tG15)^2$ + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	64.32	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	79.59	Btu/lb AF fuel	
6.4 HHV Percent Loss, as tested		0.60	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	464.30	Btu/lb AF fuel
7.2 HHV Percent Loss, as tested		3.50	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	35.94	Btu/lb AF fuel
8.2 HHV Percent Loss, as tested		0.27	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	-7.10	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	5.79	Btu/lb AF fuel
9.2 Total Dry Refuse Heat Loss, as tested		-1.30	Btu/lb AF fuel
9.3 HHV Percent Loss, as tested		-0.01	percent

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.74**
Test Date:	January 28, 2004		
Test Start Time:	10:00 AM		
Test End Time:	4:00 PM		
Test Duration, hours:	4		

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.50	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	145.61	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	47.22	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	8.58	Btu/lb
10.3 HHV Percent Loss, as tested		0.06	percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	212.04	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	1.60	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-384.13	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-170.49	Btu/lb AF Fuel
11.5 HHV Percent Loss		-1.29	percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss		0.27	percent
12.1.1	Radiation & Convection Heat Loss	36.22	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	641.07
13.1.2	79.59
13.1.3	464.30
13.1.4	35.94
13.1.5	-1.30
13.1.6	8.58
13.1.7	-170.49
13.1.8	36.22
	1,093.91

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2 - Test #2 (50/50 Blend)	**Boiler Efficiency:**	**91.74**
Test Date:	January 28, 2004		
Test Start Time:	10:00 AM		
Test End Time:	4:00 PM		
Test Duration, hours:	4		

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.84
13.1.10	Moisture In Fuel	0.60
13.1.11	H2O From H2 In Fuel	3.50
13.1.12	Unburned Combustibles In Refuse	0.27
13.1.13	Dry Refuse	-0.01
13.1.14	Moisture In Combustion Air	0.06
13.1.15	Calcination/Sulfation	-1.29
13.1.16	Radiation & Convection	0.27
		8.26
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***91.74***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	468.53	Btu/lb
14.1.2	Blow Down, Btu/lb	738.47	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	269.63	Btu/lb
14.1.5	Main Steam, Btu/lb	1462.92	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	287.42	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1291.55	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1521.67	Btu/lb
14.2 Heat Output		2,251,429,948	Btu/h
		2,253,136,163	

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,454,020,283	Btu/h
15.1.2	Fuel Burned - CALCULATED	185,199	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-0.000322748	percent

ATTACHMENT C

CAE Test Report

Black & Veatch Corporation
10751 Deerwood Park Boulevard, Suite 130
Jacksonville, FL 32256

REPORT ON
LARGE SCALE CFB COMBUSTION DEMONSTRATION PROJECT
50% PITTSBURGH NO. 8 COAL
50% PETROLEUM COKE

Performed for:

BLACK & VEATCH CORPORATION
UNIT 2, SDA INLET AND STACK
JEA - NORTHSIDE GENERATING STATION

Client Reference No: 137064.96.1400
CleanAir Project No: 9475-2
Revision 0: March 9, 2004

To the best of our knowledge, the data presented in this report are accurate and complete and error free, legible and representative of the actual emissions during the test program.

Submitted by,

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Reviewed by,

Timothy D. Rodak
Manager, Pittsburgh Regional Office

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PROJECT OVERVIEW

The Northside Generating Station Repowering project provided JEA (formerly the Jacksonville Electric Authority) with the two largest circulating fluidized bed (CFB) boilers in the world. The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Black and Veatch Corporation (B&V) contracted Clean Air Engineering, Inc. (CleanAir) to perform the air emission measurements required as part of the demonstration test program. This report covers air emission measurements obtained during the firing of a blend of 50% Pittsburgh No. 8 coal and 50% Petroleum Coke to the unit.

The test program included the measurement of the following parameters:

- particulate matter (PM), [SDA Inlet and Stack];
- sulfur dioxide (SO_2), [SDA Inlet];
- fluoride (F), [Stack];
- lead (Pb), [Stack];
- speciation of mercury (Hg^0, Hg^{2+}, Hg^{tp}), [SDA Inlet and Stack];
- ammonia (NH_3).

The field portion of the test program took place at the Unit 2 SDA Inlet and Stack locations on January 27 and 28, 2004. Coordinating the field portion of the testing were:

T. Compaan – Black and Veatch
R. Huggins – Black and Veatch
W. Goodrich - JEA
K. Davis - JEA
J. Martin - RMB
J. Stroud - Clean Air Engineering

Table 1-1 contains a summary of the specific test locations, various reference methods and sampling periods for each of the sources sampled during the program.

The results of the test program are summarized in Table 1-2. A more detailed presentation of the test data is contained in Tables 2-1 through 2-10. Process data collected during the test program is contained in Appendix H.

PROJECT OVERVIEW

Table 1-1:
Summary of Air Emission Field Test Program

Run Number	Location	Method	Analyte	Date	Start Time	End Time	Notes
1	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/27/04	11:35	12:44	
2	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/27/04	13:11	14:18	
3	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/27/04	14:57	16:04	
1	Unit 2 - SDA Inlet	Method 6C	SO2	1/27/04	11:35	12:35	
2	Unit 2 - SDA Inlet	Method 6C	SO2	1/27/04	13:11	14:11	
3	Unit 2 - SDA Inlet	Method 6C	SO2	1/27/04	14:57	15:57	
1	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	1/27/04	11:30	13:36	
2	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	1/27/04	14:58	17:57	
3	Unit 2 - SDA Inlet	Ontario Hydro	Mercury	1/27/04	18:14	20:26	
1	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/27/04	08:00	10:07	
2	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/27/04	10:35	12:43	
3	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/27/04	13:08	15:20	
1	Unit 2 Stack	Ontario Hydro	Mercury	1/27/04	11:30	13:39	
2	Unit 2 Stack	Ontario Hydro	Mercury	1/27/04	14:58	17:54	
3	Unit 2 Stack	Ontario Hydro	Mercury	1/27/04	18:14	20:23	
4	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04	10:00	11:03	
5	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04	11:10	12:16	
6	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04			(1)
7	Unit 2 - SDA Inlet	USEPA Method 17	Particulate	1/28/04	15:00	16:03	
4	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	10:01	11:01	
5	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	11:10	12:10	
6	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	12:19	12:54	(1)
7	Unit 2 - SDA Inlet	Method 6C	SO2	1/28/04	15:00	16:00	
1	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04			(2)
2	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04	10:02	11:11	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04	11:24	12:30	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04			(1)
5	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/28/04	15:00	16:04	
1	Unit 2 Stack	CTM-027	Ammonia	1/28/04	08:00	09:08	
2	Unit 2 Stack	CTM-027	Ammonia	1/28/04	10:02	11:11	
3	Unit 2 Stack	CTM-027	Ammonia	1/28/04	11:34	12:39	

Notes:
[1] EPA Method 6C - Run 6, EPA Method 13B - Run 4, EPA Method 17 - Run 6 voided to due plant problems.
[2] EPA Method 13B, Run 1 voided. Post-test leak check rate exceeded.

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PROJECT OVERVIEW

Table 1-2:
Summary of Test Results

Source Constituent	Sampling Method	Average Emission
Unit 2 SDA Inlet		
Sulfur Dioxide (ppmdv), Runs 1-3	EPA M6C	99.8
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 1-3	EPA M6C/19	0.2026
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 1-3	EPA M6C/19	0.1965
Sulfur Dioxide (ppmdv), Runs 4-6	EPA M6C	135.6
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2771
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2718
Particulate (gr/dscf), Runs 1-3	EPA M17	6.025
Particulate F_d-based, (lb/MMBtu), Runs 1-3	EPA M17/19	10.478
Particulate F_c-based, (lb/MMBtu), Runs 1-3	EPA M17/19	10.088
Particulate (gr/dscf), Runs 4-6	EPA M17	5.379
Particulate F_d-based, (lb/MMBtu), Runs 4-6	EPA M17/19	9.563
Particulate F_c-based, (lb/MMBtu), Runs 4-6	EPA M17/19	9.307
Mercury (lb/hr)	Ontario Hydro	6.615E-02
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	2.274E-05
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	2.171E-05
Unit 2 Stack		
Particulate (gr/dscf)	EPA M5	0.0022
Particulate (lb/hr)	EPA M5	11.52
Particulate F_d-based, (lb/MMBtu)	EPA M5/19	0.0041
Particulate F_c-based, (lb/MMBtu)	EPA M5/19	0.0040
Fluoride (lb/hr)	EPA M13B/19	<0.0478
Fluoride F_d-based, (lb/MMBtu)	EPA M13B/19	<1.69E-05
Fluoride F_c-based, (lb/MMBtu)	EPA M13B/19	<1.69E-05
Lead (lb/hr)	EPA M29	2.311E-03
Lead F_d-based, (lb/MMBtu)	EPA M29/19	8.224E-07
Lead F_c-based, (lb/MMBtu)	EPA M29/19	8.087E-07
Mercury (lb/hr)	Ontario Hydro	<2.360E-02
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	<8.532E-06
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	<8.251E-06
Mercury (% Removal)	Ontario Hydro/19	53.5
Ammonia (ppmdv)	CTM-027	0.325
Ammonia (lb/hr)	CTM-027	0.564
Ammonia F_d-based, (lb/MMBtu)	CTM-027/19	0.0002
Ammonia F_d-based, (lb/MMBtu)	CTM-027/19	0.0002

Notes:
1. The mass emission rate (lb/MMBtu) presented in the above table for all test parameters was calculated using a dry fuel factor (F_d) of 9,851 dscf/MMBtu and a carbon-based fuel factor (F_c) of 1,837 scf/MMBtu.
2. Total mercury emission results are shown on above table. A speciated breakdown of the mercury emissions is contained in Section 2 of the report.
3. Percent removal efficiency was calculated based on the units of F_d-based lb/MMBtu.

PROJECT OVERVIEW

PROJECT MANAGER'S COMMENTS

Ontario Hydro Test Results

Each Ontario Hydro sampling train consists of five (5) sample fractions. These fractions, starting from the sampling nozzle, consist of:

1. 0.1N HNO_3 (Front-half Rinse)
2. Filter
3. KCl (Impingers 1 through 3)
4. HNO_3-H_2O_2 (Impinger 4)
5. KMnO4 (Impingers 5 through 7)

An aliquot of each reagent and an unused filter are placed in pre-cleaned sample containers and labeled as Reagent Blanks. In addition, a sampling train is prepared, taken to the respective sampling location, leak-checked and allowed to remain at the sampling location a duration comparable to the length of a sampling run. The train is then recovered and each of the five fractions listed above are labeled as a Field Train Blanks.

Laboratory results indicated elevated mercury levels in the Fraction 4 (HNO_3-H_2O_2, Elemental Mercury Fraction) of the Reagent Blank and the Field Train Blanks (SDA Inlet and Stack) [Appendix G].

The mercury concentration in the remaining four sample fractions of the Reagent and Field Blanks were at acceptable levels or below the method detection limit.

The Ontario Hydro Method maximum allowable blank adjustment, outlined in Section 13.41, is based on the following criteria:

1. 10% of the measured regent blank value (6.20 ug) or,
2. Ten (10) times the method detection limit of 0.005 ug (0.05 ug), whichever is less.

The numbers indicated in the parentheses are applicable to fraction 4 (HNO_3-H_2O_2).

In accordance with the above criteria a maximum blank correction of 0.05 ug was applied to the fraction 4 (HNO3-H2O2) data and these results are shown in this report. Review of the laboratory, sampling and recovery procedures indicates that the elevated mercury present in fraction 4 of the samples was most likely attributed to the HNO_3-H_2O_2 reagent and present prior to testing. Therefore, in allowing a maximum blank value of 0.05 ug the results may show an emission rate biased higher than those present in the flue gas stream.

PROJECT OVERVIEW

Based on the above information, applying a correction to the fraction 4 portion of the sample train equivalent to the fraction 4 value of the respective Field Blank Trains is recommended (i.e., SDA Inlet = 35.8 ug and Stack = 22.6 ug).

Following this modified blank correction procedure the average total mercury emissions (F_d-based lb/MMBtu) at the SDA Inlet and Stack would be 1.426E-05 and 5.434E-07, respectively. This calculates to an average removal efficiency of 97.0%.

RESULTS

Table 2-1:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 1 through 3

Run No.	**1**	**2**	**3**	**Average**
Date (2004)	January 27	January 27	January 27	
Start Time	11:35	13:11	14:57	
End Time	12:35	14:11	15:57	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	**9,851**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	**1,837**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Oxygen (dry volume %)	4.1	4.0	4.0	**4.0**
Carbon dioxide (dry volume %)	15.6	15.5	15.4	**15.5**
Actual water vapor in gas (% by volume)	7.88	6.81	6.50	**7.06**
Volumetric flow rate, actual (acfm)	985,459	983,592	983,917	**984,323**
Volumetric flow rate, standard (scfm)	639,139	632,012	634,453	**635,201**
Volumetric flow rate, dry standard (dscfm)	588,774	588,994	593,203	**590,324**
Sulfur Dioxide (SO_2) Results				
Concentration (ppmdv)	101.9	75.3	122.2	**99.8**
Mass Emission Rate (lb/hr)	598.5	442.7	723.2	**588.1**
Mass Emission Rate (ton/year)	2,622	1,939	3,168	**2,576**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2077	0.1527	0.2475	**0.2026**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.1999	0.1481	0.2417	**0.1965**

RESULTS

Table 2-2:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 4 through 6

Run No.	**4**	**5**	**7**	**Average**
Date (2004)	January 28	January 28	January 28	
Start Time	10:01	11:10	15:00	
End Time	11:01	12:10	16:00	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	**9,851**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	**1,837**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Oxygen (dry volume %)	4.2	4.1	4.2	**4.1**
Carbon dioxide (dry volume %)	15.1	15.2	15.4	**15.2**
Actual water vapor in gas (% by volume)	7.05	6.89	6.56	**6.84**
Volumetric flow rate, actual (acfm)	966,174	956,170	968,672	**963,672**
Volumetric flow rate, standard (scfm)	632,018	632,876	632,315	**632,403**
Volumetric flow rate, dry standard (dscfm)	587,468	589,246	590,807	**589,174**
Sulfur Dioxide (SO_2) Results				
Concentration (ppmdv)	144.8	124.4	137.6	**135.6**
Mass Emission Rate (lb/hr)	848.7	731.1	811.3	**797.0**
Mass Emission Rate (ton/year)	3,717	3,202	3,553	**3,491**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2969	0.2527	0.2817	**0.2771**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.2931	0.2498	0.2725	**0.2718**

RESULTS

Table 2-3:
Unit 2 – SDA Inlet – Particulate Matter, Runs 1 through 3

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		11:35	13:11	14:57	
Stop Time (approx.)		12:44	14:18	16:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.2	3.8	4.0	**4.0**
CO_2	Carbon dioxide (dry volume %)	15.6	15.8	15.6	**15.7**
T_s	Sample temperature (°F)	315	322	319	**318**
B_w	Actual water vapor in gas (% by volume)	7.88	6.81	6.50	**7.06**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	985,459	983,592	983,917	**984,323**
Q_s	Volumetric flow rate, standard (scfm)	639,139	632,012	634,453	**635,201**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	588,774	588,994	593,203	**590,324**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	5.3389	7.1792	5.5577	**6.0253**
$E_{lb/hr}$	Particulate Rate (lb/hr)	26,952	36,256	28,268	**30,492**
$E_{T/yr}$	Particulate Rate (Ton/yr)	118,051	158,802	123,813	**133,555**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	9.4060	12.3524	9.6756	**10.4780**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	8.9842	11.9281	9.3524	**10.0882**

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RESULTS

Table 2-4:
Unit 2 – SDA Inlet – Particulate Matter, Runs 4 through 6

Run No.		4	5	7	Average
Date (2004)		Jan 28	Jan 28	Jan 28	
Start Time (approx.)		10:00	11:10	15:00	
Stop Time (approx.)		11:03	12:16	16:03	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.3	4.5	4.2	**4.3**
CO_2	Carbon dioxide (dry volume %)	15.2	15.0	15.4	**15.2**
T_s	Sample temperature (°F)	308	300	310	**306**
B_w	Actual water vapor in gas (% by volume)	7.05	6.89	6.56	**6.84**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	966,174	956,170	968,672	**963,672**
Q_s	Volumetric flow rate, standard (scfm)	632,018	632,876	632,315	**632,403**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	587,468	589,246	590,807	**589,174**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	6.2515	6.0481	3.8358	**5.3785**
$E_{lb/hr}$	Particulate Rate (lb/hr)	31,489	30,557	19,431	**27,159**
$E_{T/yr}$	Particulate Rate (Ton/yr)	137,922	133,840	85,108	**118,957**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	11.0801	10.8505	6.7579	**9.5628**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	10.7967	10.5848	6.5387	**9.3067**

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RESULTS

Table 2-5:
Unit 2 – SDA Inlet – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		11:30	14:58	18:14	
Stop Time (approx.)		13:36	17:57	20:26	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.0	4.2	4.3	**4.2**
CO_2	Carbon dioxide (dry volume %)	15.7	15.6	15.6	**15.6**
T_s	Sample temperature (°F)	311	315	310	**312**
B_w	Actual water vapor in gas (% by volume)	7.18	7.47	6.91	**7.19**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	993,457	986,276	989,118	**989,617**
Q_s	Volumetric flow rate, standard (scfm)	647,181	639,188	645,156	**643,841**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	600,693	591,450	600,596	**597,580**
Total Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	5.427E-02	7.865E-02	6.553E-02	**6.615E-02**
$E_{T/yr}$	Rate (Ton/yr)	2.377E-01	3.445E-01	2.870E-01	**2.897E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.834E-05	2.733E-05	2.255E-05	**2.274E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.762E-05	2.610E-05	2.141E-05	**2.171E-05**
Particulate Bound Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	3.458E-02	4.405E-02	4.110E-02	**3.991E-02**
$E_{T/yr}$	Rate (Ton/yr)	1.514E-01	1.929E-01	1.800E-01	**1.748E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.169E-05	1.530E-05	1.414E-05	**1.371E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.122E-05	1.462E-05	1.343E-05	**1.309E-05**
Oxidized Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	1.751E-04	4.127E-04	4.040E-04	**3.306E-04**
$E_{T/yr}$	Rate (Ton/yr)	7.671E-04	1.808E-03	1.770E-03	**1.448E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	5.920E-08	1.434E-07	1.391E-07	**1.139E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	5.686E-08	1.370E-07	1.320E-07	**1.086E-07**
Elemental Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	1.951E-02	3.419E-02	2.403E-02	**2.591E-02**
$E_{T/yr}$	Rate (Ton/yr)	8.547E-02	1.498E-01	1.052E-01	**1.135E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	6.596E-06	1.188E-05	8.269E-06	**8.914E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	6.335E-06	1.135E-05	7.851E-06	**8.511E-06**

[1] The elemental mercury (HNO_3-H_2O_2 fraction) was calculated using the maximum allowable blank value of (0.05 ug) which is ten (10) times the laboratory detection limit of 0.005 ug.

RESULTS

Table 2-6:
Unit 2 – Stack – Particulate Matter

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		08:00	10:35	13:08	
Stop Time (approx.)		10:07	12:43	15:20	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.0	4.6	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.0	14.7	14.9	**14.5**
T_s	Sample temperature (°F)	226	228	235	**229**
B_w	Actual water vapor in gas (% by volume)	10.76	10.68	10.52	**10.65**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	900,538	897,667	896,953	**898,386**
Q_s	Volumetric flow rate, standard (scfm)	689,974	685,607	677,997	**684,526**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	615,732	612,366	606,699	**611,599**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	0.0018	0.0024	0.0024	**0.0022**
$E_{lb/hr}$	Particulate Rate (lb/hr)	9.32	12.57	12.68	**11.52**
$E_{T/yr}$	Particulate Rate (Ton/yr)	40.82	55.07	55.54	**50.47**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	0.0034	0.0044	0.0044	**0.0041**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	0.0033	0.0043	0.0043	**0.0040**

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RESULTS

Table 2-7:
Unit 2 – Stack - Fluoride

Run No.		2	3	5	Average
Date (2004)		Jan 28	Jan 28	Jan 28	
Start Time (approx.)		10:02	11:24	15:00	
Stop Time (approx.)		11:11	12:30	16:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.2	4.9	4.8	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.3	14.7	14.8	**14.6**
T_s	Sample temperature (°F)	235	226	222	**227**
B_w	Actual water vapor in gas (% by volume)	8.51	8.92	9.18	**8.87**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	870,686	867,477	867,526	**868,563**
Q_s	Volumetric flow rate, standard (scfm)	661,986	668,606	672,322	**667,638**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	605,644	608,958	610,603	**608,402**
Hydrogen Fluoride (HF) Results [1]					
C_{sd}	HF Concentration (ppmdv)	<0.0258	<0.0201	<0.0298	**<0.0253**
$E_{lb/hr}$	HF Rate (lb/hr)	<0.0487	<0.0381	<0.0567	**<0.0478**
$E_{T/yr}$	HF Rate (Ton/yr)	<0.2134	<0.1668	<0.2485	**<0.2096**
E_{Fd}	HF Rate - Fd-based (lb/MMBtu)	<1.76E-05	<1.34E-05	<1.98E-05	**<1.69E-05**
E_{Fc}	HF Rate - Fc-based (lb/MMBtu)	<1.72E-05	<1.30E-05	<1.92E-05	**<1.65E-05**

[1] The "less than" sign indicates that the sample was below the laboratory minimum detection limit of 0.06 mg/liter. The minimum detection limit was used in the calculations.

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RESULTS

Table 2-8:
Unit 2 – Stack – Lead

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		08:00	10:35	13:08	
Stop Time (approx.)		10:07	12:43	15:20	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.0	4.6	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.0	14.7	14.9	**14.5**
T_s	Sample temperature (°F)	226	228	235	**229**
B_w	Actual water vapor in gas (% by volume)	10.76	10.68	10.52	**10.65**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	900,538	897,667	896,953	**898,386**
Q_s	Volumetric flow rate, standard (scfm)	689,974	685,607	677,997	**684,526**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	615,732	612,366	606,699	**611,599**
Lead Results - Total					
$E_{lb/hr}$	Rate (lb/hr)	4.712E-03	5.092E-04	1.711E-03	**2.311E-03**
$E_{T/yr}$	Rate (Ton/yr)	2.064E-02	2.230E-03	7.495E-03	**1.012E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.694E-06	1.795E-07	5.938E-07	**8.224E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.673E-06	1.732E-07	5.796E-07	**8.087E-07**

RESULTS

Table 2-9:
Unit 2 – Stack – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 27	Jan 27	Jan 27	
Start Time (approx.)		11:30	14:58	18:14	
Stop Time (approx.)		13:39	17:54	20:23	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	4.7	4.8	**4.8**
CO_2	Carbon dioxide (dry volume %)	14.9	14.8	14.8	**14.8**
T_s	Sample temperature (°F)	215	222	232	**223**
B_w	Actual water vapor in gas (% by volume)	10.64	10.23	10.51	**10.46**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	843,739	846,892	885,409	**858,680**
Q_s	Volumetric flow rate, standard (scfm)	651,187	653,047	672,266	**658,833**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	581,926	586,245	601,600	**589,924**
Total Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<2.083E-02	<2.326E-02	<2.672E-02	**<2.360E-02**
$E_{T/yr}$	Rate (Ton/yr)	<9.126E-02	<1.019E-01	<1.170E-01	**<1.034E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.727E-06	<8.404E-06	<9.465E-06	**<8.532E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.357E-06	<8.208E-06	<9.187E-06	**<8.251E-06**
RE	Removal Efficiency (%) Fd-based (lb/MMBtu)	57.9%	54.2%	48.4%	**53.5%**
Particulate Bound Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<2.040E-06	<2.052E-06	<2.112E-06	**<2.068E-06**
$E_{T/yr}$	Rate (Ton/yr)	<8.933E-06	<8.988E-06	<9.250E-06	**<9.057E-06**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.564E-10	<7.414E-10	<7.482E-10	**<7.487E-10**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.202E-10	<7.241E-10	<7.262E-10	**<7.235E-10**
Oxidized Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	<4.079E-05	<4.104E-05	8.447E-05	**<5.544E-05**
$E_{T/yr}$	Rate (Ton/yr)	<1.787E-04	<1.798E-04	3.700E-04	**<2.428E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<1.513E-08	<1.483E-08	2.993E-08	**<1.996E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<1.440E-08	<1.448E-08	2.905E-08	**<1.931E-08**
Elemental Mercury Results					
$E_{lb/hr}$	Rate (lb/hr)	2.081E-02	2.324E-02	2.663E-02	**2.356E-02**
$E_{T/yr}$	Rate (Ton/yr)	9.116E-02	1.018E-01	1.166E-01	**1.032E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.719E-06	8.397E-06	9.435E-06	**8.517E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.349E-06	8.200E-06	9.157E-06	**8.236E-06**

[1] Less than symbol indicates that one or more factions (oxidized mercury) were below the laboratory minimum detection limit. Any fraction below the minimum detection limit was calculated using a value of 0.5 times the non-detect value.

[2] Removal efficiency calculate using F_d-based (lb/MMBtu)

[3] The elemental mercury (HNO_3-H_2O_2 fraction) was calculated using the maximum allowable blank value of (0.05 ug) which is ten (10) times the laboratory detection limit of 0.005 ug.

RESULTS

Table 2-10:
Unit 2 – Stack - Ammonia

Run No.		1	2	3	Average
Date (2004)		Jan 28	Jan 28	Jan 28	
Start Time (approx.)		08:00	10:02	11:34	
Stop Time (approx.)		09:08	11:11	12:39	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,851	9,851	9,851	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,837	1,837	1,837	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	5.1	4.9	**5.0**
CO_2	Carbon dioxide (dry volume %)	14.4	14.4	14.6	**14.5**
T_s	Sample temperature (°F)	221	237	227	**228**
B_w	Actual water vapor in gas (% by volume)	7.20	8.99	8.74	**8.31**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	952,145	917,860	910,351	**926,785**
Q_s	Volumetric flow rate, standard (scfm)	739,165	695,434	699,865	**711,488**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	685,981	632,929	638,684	**652,531**
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (ppmdv)	0.3656	0.3027	0.3068	**0.3250**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	0.6647	0.5079	0.5194	**0.5640**
$E_{T/yr}$	Ammonia Rate (Ton/yr)	2.9114	2.2245	2.2748	**2.4702**
E_{Fd}	Ammonia Rate - Fd-based (lb/MMBtu)	0.0002	0.0002	0.0002	**0.0002**
E_{Fc}	Ammonia Rate - Fc-based (lb/MMBtu)	0.0002	0.0002	0.0002	**0.0002**

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DESCRIPTION OF INSTALLATION

PROCESS DESCRIPTION

The Jacksonville Electric Northside Generating Station Unit 2 consists of a 300 MW circulating fluidized bed (CFB) boiler a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The control system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

The testing reported in this document was performed at the Unit 2 SDA Inlet and Stack locations.

A schematic of the process indicating sampling locations is shown in Figure 3-1.

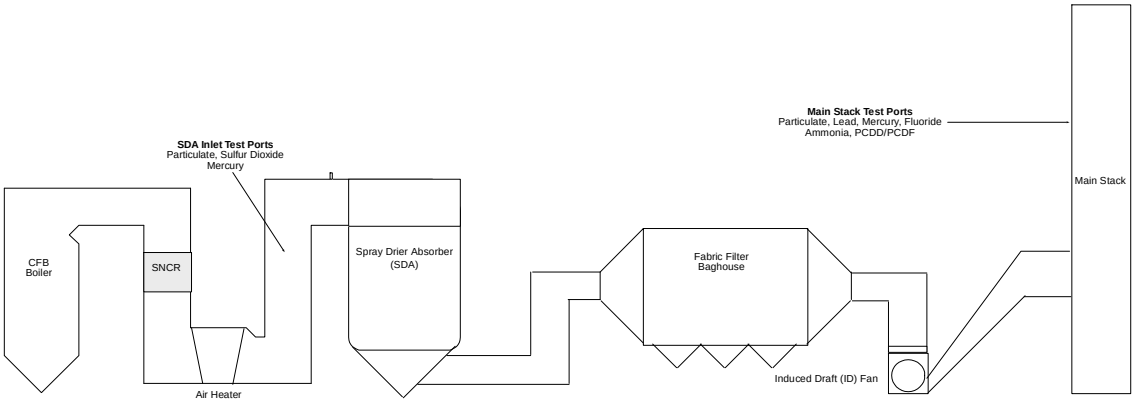


Figure 3-1: Process Schematic

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION(S)

Sampling point locations were determined according to EPA Method 1.

Table 3-1 outlines the sampling point configurations. Figure 3-3 and 3-3 illustrate the sampling points and orientation of sampling ports for each of the sources tested in the program.

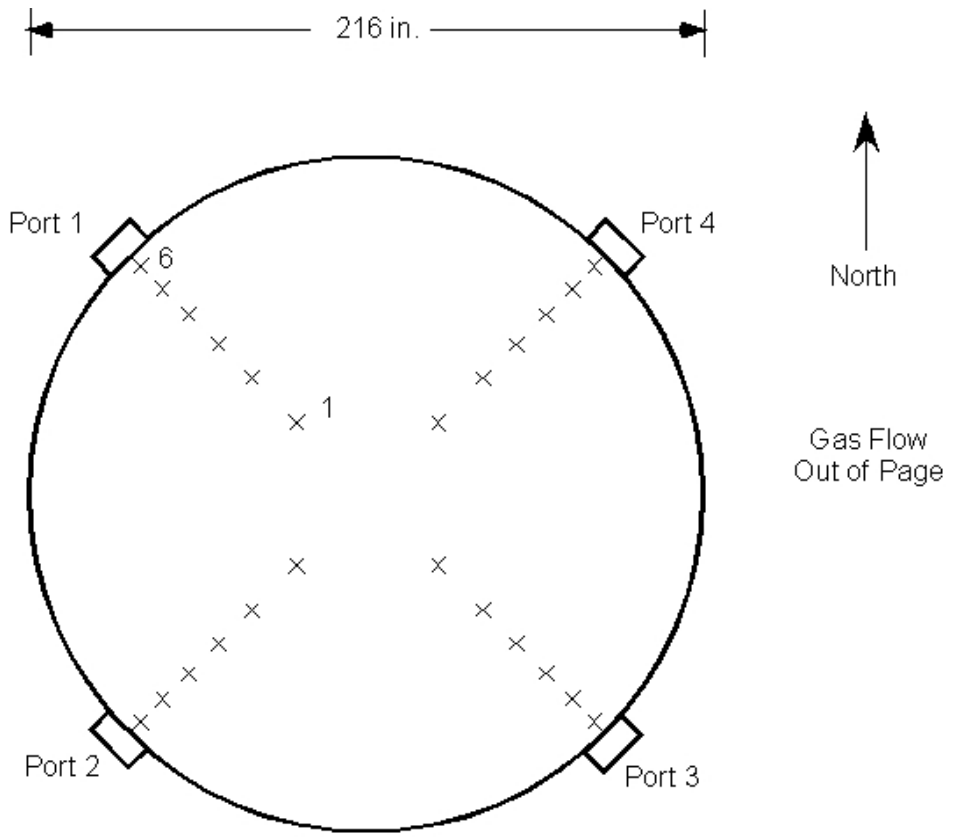
Table 3-1:
Sampling Points

Location	Constituent	Method	Run No.	Ports	Points per Port	Minutes per Point	Total Minutes	Figure
Unit 2 SDA Inlet	SO2	6C	1-7	1	1	60[1]	60	N/A
Unit 2 SDA Inlet	Particulate	17	1-7	4	6	2.5	60	3-1
Unit 2 SDA Inlet	Mercury	OH[2]	1-3	4	6	5	120	3-1
Unit 2 Stack	Particulate	5	1-3	4	3	10	120	3-2
Unit 2 Stack	Fluoride	13B	1-5	4	3	5	60	3-2
Unit 2 Stack	Lead	29	1-3	4	3	10	120	3-2
Unit 2 Stack	Mercury	OH[2]	1-3	4	3	10	120	3-2
Unit 2 Stack	Ammonia	CTM-027	1-3	4	3	5	60	3-2

[1] Sulfur Dioxide was sampled from a single point in the duct. Readings were collected at one-second intervals by the computer based data acquisition system and reported as one-minute averages.
[2] Mercury was determined using the Ontario Hydro method.

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



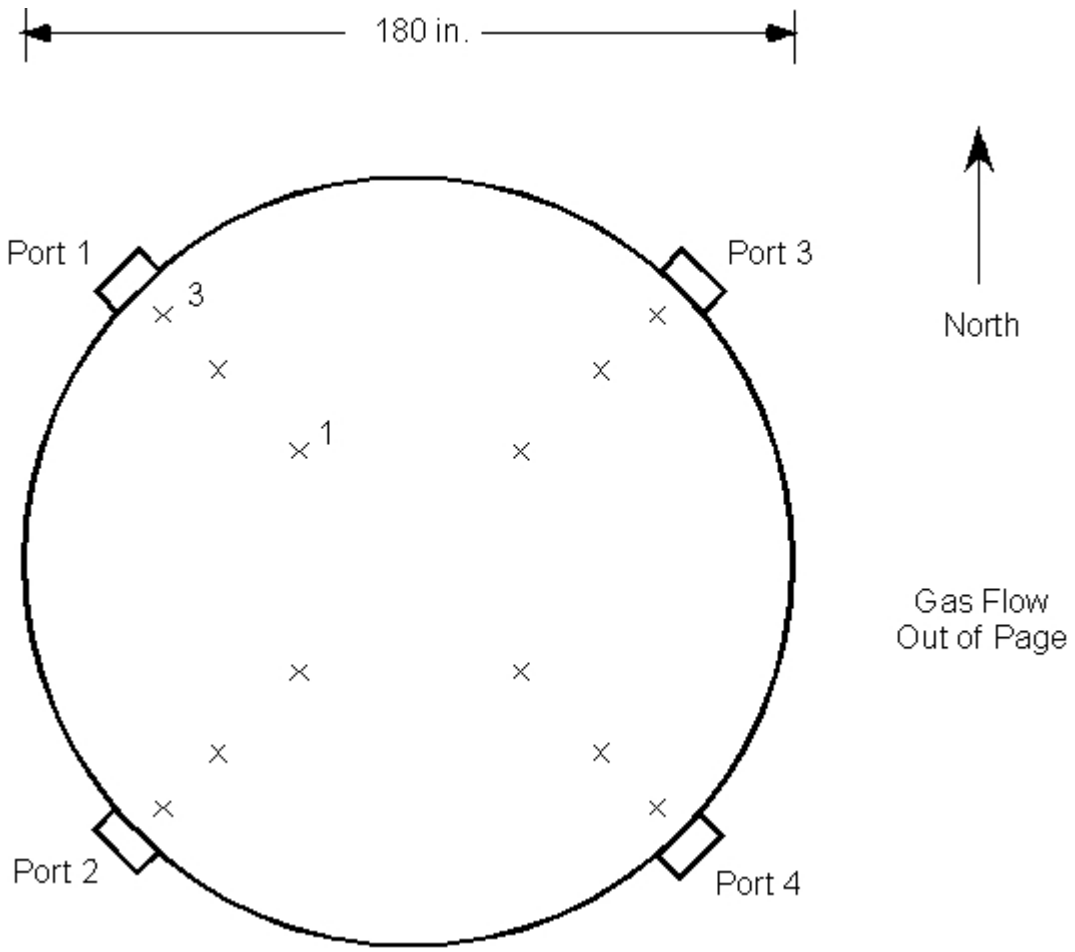
Sampling Point	Port to Point Distance (in.)
1	76.9
2	54.0
3	38.2
4	25.5
5	14.5
6	4.5

Diameters to upstream disturbance: >2.0 — Limit: 2.0 (minimum)
Diameters to downstream disturbance: >0.5 — Limit: 0.5 (minimum)

Figure 3-2: SDA Inlet Sampling Point Determination (EPA Method 1)

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



Sampling Point	Port to Point Distance (in.)
1	53.3
2	26.3
3	7.9

Diameters to upstream disturbance: >8.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >2.0 Limit: 0.5 (minimum)

Figure 3-3: Stack Sampling Point Determination (EPA Method 1)

METHODOLOGY

Clean Air Engineering followed procedures as detailed in U.S. Environmental Protection Agency (EPA) Methods 1, 2, 3A, 4, 5, 6C, 13B, 23, 29, Conditional Test Method CTM-027 and the Ontario Hydro Method. The following table summarizes the methods and their respective sources.

Table 4-1:
Summary of Sampling Procedures

Title 40 CFR Part 60 Appendix A	
Method 1	"Sample and Velocity Traverses for Stationary Sources"
Method 2	"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)"
Method 3A	"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 4	"Determination of Moisture Content in Stack Gases"
Method 5	"Determination of Particulate Emissions from Stationary Sources"
Method 6C	"Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 13B	"Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)"
Method 23	"Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources"
Method 29	"Determination of Metals Emissions from Stationary Sources"
Conditional Test Method	
CTM-027	"Procedure for the Collection and Analysis of Ammonia in Stationary Sources."
Draft Methods	
Ontario Hydro	"Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources."

The EPA Methods (1 through 29) appear in detail in Title 40 of the Code of Federal Regulations (CFR). The Conditional Test Method and the Hydro Ontario Method appear in detail on the US EPA Emissions Measurement Center web page. All methods may be found on the World Wide Web at http://www.cleanair.com.

Diagrams of the sampling apparatus and major specifications of the sampling, recovery and analytical procedures are summarized for each method in Appendix A.

Clean Air Engineering followed specific quality assurance and quality control (QA/QC) procedures as outlined in the individual methods and in USEPA "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III Stationary Source-Specific Methods", EPA/600/R-94/038C. Additional QA/QC methods as prescribed in Clean Air's internal Quality Manual were also followed. Results of all QA/QC activities performed by Clean Air Engineering are summarized in Appendix D.

APPENDIX

TEST METHOD SPECIFICATIONS ..... A
SAMPLE CALCULATIONS ..... B
PARAMETERS C
QA/QC DATA ..... D
FIELD DATA ..... E
FIELD DATA PRINTOUTS ..... F
LABORATORY DATA ..... G
FACILITY OPERATING DATA ..... H

ATTACHMENT D

PI Data Summary

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Date:	**January 27, 2004**	**January 28, 2004**
Start:	**1130 hours**	**1000 hours**
End:	**1530 hours**	**1600 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air	Avg. Out A and B, Deg F	102.7	87.5
	Average, deg F	108.0	95.7
	Count	480	480
	Standard Deviation	2.8720	7.0768
Secondary Air	Total SA flow, klb/hr	0.7020	0.61
	Average, Total SA Flow, klb/hr	0.7011	0.63
	Count	240	240
	Standard Deviation	0.0084	0.0458
	Avg. Out A and B, Deg F	103.4	88.65
	Average, deg F	109.7	95.30
	Count	480	480
	Standard Deviation	6.8505	7.4273
Fuel	Total Flow, klb/hr	194.5	195.12
	Average, deg F	194.2	195.18
	Count	240	240
	Standard Deviation	0.3008	0.4515
PAHTR Gas Out	Gas Out, deg F, A train	295.7	288.10
	Gas Out, deg F, B train	309.3	303.83
	Average, deg F	311.1	298.65
	Count	480	480
	Standard Deviation	7.7917	8.2852
SAHTR Gas Out	Gas Out, deg F, A train	288.4	286.55
	Gas Out, deg F, B train	288.2	294.79
	Average, deg F	289.8	282.62
	Count	480	480
	Standard Deviation	11.8296	11.2515
PAH Gas In	Gas In, deg F, A & B train	563.7	575.73
	Average, deg F	572.5	568.58
	Count	240	240
	Standard Deviation	4.8307	4.5239
SAH Gas In	Gas In, deg F A & B train	566.6	579.20
	Average, deg F	575.7	571.83
	Count	240	240
	Standard Deviation	5.0519	4.7635
PAH Air Out	Air Out, deg F A & B train	461.6	464.06
	Average, deg F	470.7	461.60
	Count	240	240
	Standard Deviation	4.0990	3.4760
SA Airheater Air Out	Air Out, deg F A & B train	431.3	441.20
	Average, deg F	434.3	435.22
	Count	240	240
	Standard Deviation	3.12231	3.98815

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
	Ash leaving temperature, deg F, A	0.0	0.00
	Ash leaving temperature, deg F, B	0.0	0.00
Stripper/	Ash leaving temperature, deg F, C	0.0	0.00
Coolers - A, B,	Ash leaving temperature, deg F, D	0.0	0.00
C, D	Average, deg F	0.0	0.00
	Count	480	480
	Standard Deviation	0.0000	0.000
	Temperature, deg F		
SDA Hopper	Average, deg F	210.3	209.95
	Count	240	240
	Standard Deviation	3.9223	6.2670
	Feedrate, feeders 1, 2, 3, klb/hr	72.3	65.25
Limestone	Average, klb/hr	66.4	73.0
Feed Rate 1	Count	240	240
	Standard Deviation	11.6244	3.9721
	AH inlet, ppm		
SO2, in flue	Average, ppm mv	27.1	51.87
Gas	Count	240	240
	Standard Deviation	13.6302	15.4369
	Flow to A, B, C, lb/hr	35896.6	35776.20
Intrex Blower	Average, lb/hr	35790.2	35983.87
Air Flow	Count	1440	1440
	Standard Deviation	98.0315	158.7149
	PA Flow to Intrex A, B, C, lb/hr	45404.1	45975.88
Intrex Seal Pot	Average, lb/hr	44706.3	45157.57
Blower	Count	240	240
	Standard Deviation	1010.0263	972.9776
Intrex Blower	Average, deg F	165.8	150.41
Exit Air Temp	Count	240	240
	Standard Deviation	2.8880	6.2597
Seal Pot	Average, deg F	178.3	162.09
Blower Exit Air	Count	240	240
Temp	Standard Deviation	3.6163	5.4888
Feedwater	Average, deg F	484.3	483.53
Temperature to	Count	240	240
Econ	Standard Deviation	1.1649	0.8814
Feedwater	Average, psiG	1533.2	1501.89
Pressure to	Count	240	240
Econ	Standard Deviation	5.8658	19.6988
(DSH)SH-1	Average, klb/hr	19.1	22.82
Spray Flow	Count	240	240
	Standard Deviation	2.2703	4.1563

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
SH-1 Spray Temperature	Average, deg F	303.0	295.14
	Count	240	240
	Standard Deviation	1.8619	4.2962
SH-1 Spray Pressure	Average, psiG	2700.6	2699.71
	Count	240	240
	Standard Deviation	8.1842	5.2985
Drum Pressure	Average of three pressure values	2562.8	2561.88
	Average, psiG	2561.5	2561.98
	Count	720	720
	Standard Deviation	8.2880	5.1986
Main Steam Temperature	Average, deg F	1003.5	1002.70
	Count	240.0	240
	Standard Deviation	1.5012	0.7836
Main Steam Pressure	Average of two pressure values	2403.3	998.74
	Average, psiG	2400.7	999.81
	Count	480.0	480
	Standard Deviation	5.5393	1.0825
Reheater Outlet Temperature	Average of three temp values	1008.4	1007.91
	Average, deg F	1007.5	1008.17
	Count	720.0	720
	Standard Deviation	3.5757	1.5791
Reheater Outlet Pressure	Average of two pressure values	567.6	566.6
	Average, psiG	569.1	565.4
	Count	480	480
	Standard Deviation	25.8969	25.6913
CRH Ent Attemp Temp	Average, deg F	604.0	599.83
	Count	240.0	240
	Standard Deviation	4.8862	7.7452
CRH Ent Attemp Press	Average, psiG	568.4	564.91
	Count	240.0	240
	Standard Deviation	6.9791	5.5262
RH Spray Flow	Average, klb/hr	1.4	2.16
	Count	240	240
	Standard Deviation	2.4150	3.0002
RH Spray Temp	Average, deg F	300.9	316.17
	Count	240	240
	Standard Deviation	28.2255	16.4067
RH Spray Pressure	Average, psiG	713.7	708.45
	Count	240	240
	Standard Deviation	24.1003	28.4373

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Htr 1 FW Entering Temp	Data	417.6	417
	Data	483.8	484.2
	Average, deg F	451.1	450.25
	Count	480	480
	Standard Deviation	33.2734	33.3245
Htr 1 FW Entering Pressure	Data	1541.9	1521.5
	Data	1541.9	1521.5
	Average, psiG	1533.2	1501.9
	Count	480	480
	Standard Deviation	5.8597	19.6782
Htr 1 FW Leaving Temp	Average, deg F	484.3	483.53
	Count	240	240
	Standard Deviation	1.1649	0.8814
Htr 1 FW Leaving Pressure	Average, psiG	1533.2	1501.9
	Count	240	240
	Standard Deviation	5.8658	19.6988
Htr 1 Extraction Stm Temp	Average, deg F	632.7	630.3
	Count	240	240
	Standard Deviation	2.3422	1.1165
Htr 1 Extraction Stm Pressure	Average, psiG	572.0	568.2
	Count	240	240
	Standard Deviation	6.7983	5.5608
Htr 1 Drain Temp	Average, deg F	423.1	422.3
	Count	240	240
	Standard Deviation	0.9820	0.8009
Htr 1 Drain Pressure	Average, psiG	572.0	568.2
	Count	240.0	240
	Standard Deviation	6.7983	5.5608
Feedwater to Econ	Pressure, psiG	1556.6	1536.4
	Temperature, deg F	483.8	484.2
	Density, lb / cu. ft.	0.01990	0.0199
Primary Air to SC A	Total of three flow values	47.6	48.2
	Average, k lb/hr	47.0	47.7
	Count	240	240
	Standard Deviation	0.2949	0.3281
Primary Air to SC B	Total of three flow values	10.3	10.3
	Average, k lb/hr	10.3	10.3
	Count	240	240
	Standard Deviation	0.0412	0.0656
Primary Air to SC C	Total of three flow values	14.3	14.5
	Average, k lb/hr	14.1	14.3
	Count	240	240
	Standard Deviation	0.1	0.1073

JEA Northside Unit 2
Test #2
50 / 50 Blend - Pittsburgh 8 Coal Pet Coke
SUMMARY PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air to SC D	Total of three flow values	46.6	46.8
	Average, k lb/hr	46.0	45.9
	Count	240	240
	Standard Deviation	0.4491	1.5559
Combustion Air Flow into PAH (hot), lb/hr	Total of fourteen flow values	13878.8	14104.5
	Average, k lb/hr	13853.4	14054.1
	Count	240	240
	Standard Deviation	55.7703	51.5375
Combustion Air Flow bypassing PAH (cold), lb/hr	Total of four flow values	53.9	54.9
	Average, k lb/hr	53.2	53.9
	Count	240	240
	Standard Deviation	0.2761	0.6130
Total air Flow, klb/hr	Average, k lb/hr	2393.5	2382.7
	Count	240	240
	Standard Deviation	7.8346	11.5825

ATTACHMENT E

Abbreviation List - Refer to Section 1.2

ATTACHMENT F

Isolation Valve List

Hole #	Description	Approximate Location	Closed (Yes / No)			
			13-Jan-04	14-Jan-04	15-Jan-04	16-Jan-04
37	RHA to CRH	Next to Heat 1	closed	closed	closed	closed
Use Digital Readout	MS Bypass to CRH (Upstream)	Next to Heater 1	closed	closed	closed	closed
38	Desup Wtr from BFP Disch to MS Bypass		closed	closed	closed	closed
Bare Pipe	Heater 1 ~~Running~~ Vent	On Side of Heater 1	closed	closed	closed	closed
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	closed	closed	closed	closed
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	closed	closed	closed	closed
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	closed	closed	closed	closed
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	closed	closed	closed	closed
33	Aux Steam Header (GRAY Valve) 337	Platform Overhead	closed	closed	closed	closed
55	CRH Line Drains - common line	Below Turbine	closed	closed	~~open~~ closed	closed
56	CRH Line Drains - common line	Below Turbine	closed	closed	closed	closed
57	CRH Line Drains - North	Below Turbine	closed	closed	closed	closed
58	CRH Line Drains - South	Below Turbine	closed	closed	closed	closed
60	MS Line Drain	Below Turbine	closed	closed	closed	closed
61	MS Line Drain	Below Turbine	closed	closed	closed	closed
#1	Extraction Drain	Below Turbine	closed	closed	closed	closed
	Heat Soak Valve SA330	Below Turbine	closed	closed	closed	closed

#1 Heater Shell Drain balking small amount

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
Mezzanine Level			
35	DA Pegging Steam (Upstream)	Next to Heater 1	
36	DA Pegging Steam (Downstream)	Next to Heater 1	
34	DA Pegging Steam Line Drain	Next to Heater 1	
37	RHA to CRH	Next to Heater 1	
39	MS Bypass to CRH (Upstream)	Over railing by Heater 1	
Use Digital Readout	MS Bypass to CRH (Downstream)	Next to Heater 1	
38	Desup Wtr from BFP Disch to MS Bypass	Near railing by Heater 1	
Bare Pipe	Heater 1 Running Vent	On Side of Heater 1	
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	
Visual	Heater 1 FW Bypass	Directly above Heater 1	
Bare Pipe	Heater 2 Running Vent	On Side of Heater 2	
Bare Pipe	Heater 2 Relief Vent	Top of Heater 2	
Visual	Heater 2 FW Bypass	Directly above Heater 2	
41	Aux Steam to Unit 3 CRH	Against wall - stairs near Htr 5	
40	Aux Steam from Unit 3 CRH	Against wall - stairs near Htr 5	
42	MS to SSH	Platform (overhead)	
43	SSR Bypass Line	Platform (overhead)	
44	Aux Steam Supply Line to SSR	Vertical Pipe near Platform	
Gauge	SSH Pressure	Board on Platform	
45	Heater 4 Running Vent	Side of Heater 4	
Bare Pipe	Heater 4 Relief Vent	Top of Heater 4	
Visual	Heater 4 FW Bypass	Directly above Heater 4	
46	Heater 5 Vent	Side of Heater 5	
47	Heater 5 Vent	Side of Heater 5	
Bare Pipe	Heater 5 Relief Vent	Top of Heater 5	
Visual	Heater 5 FW Bypass	Directly above Heater 5	
48	CBP Disch to BFP Suction	To the side of Heater 5	
Visual	Heater 6 FW Bypass	Near Condenser Wall	
19	BDV to Cond	Near Condenser Wall (right side)	
20	RFDV (Ventilator Valve) to Cond	Bare Pipe near Cond Wall (R/S)	
21	Equalizer Valve to Cond (CRV-1)	Bare Pipe near Cond Wall (R/S)	
22	Equalizer Valve to Cond (CRV-2)	Bare Pipe near Cond Wall (R/S)	
12	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
14	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
52	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
53	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
13	Stm Lead Drains	Near Condenser Wall (R/S)	
16	Stm Lead Drains	Near Condenser Wall (R/S)	
17	Stm Lead Drains	Near Condenser Wall (R/S)	
18	Stm Lead Drains	Near Condenser Wall (R/S)	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
15	CRV Drain Lines	Near HRH Line	
23	CRV Drain Lines	Hear HRH Line	
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	
DCS	HRH Bypass to Condenser (Downstream)	Control Room	
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	
Visual	SDBFP Recirc to DA	Near HRH Bypass Line	
Visual	MDBFP Recirc to DA	Near HRH Bypass Line	
	Condenser Vacuum		

Ground Floor

24	TDV to Cond (SS Dump)	Into Condenser (use platform)	
7	CRH Drain Hdr 1	Hdr into Cond on Left Side	
8	MS Drain Hdr 2	Hdr into Cond on Left Side	
6	Extraction Drain Hdr 3	Hdr into Cond on Left Side	
10	Drain Hdr 4	Hdr into Cond on Right Side	
9	Drain Hdr 5	Hdr into Cond on Right Side	
11	Steam Lead Drains	Bare Pipe - Side of Condenser	
51	BAC Return to Condenser (CV-4)	U/S of CV-4	
Double Isolate	Hotwell Makeup		
	Polisher Drains	Near Condensate Polishing Sys	
	Bitter Water Pump Off	Near Condensate Polishing Sys	Yes / No
	Unit 2 Fill Pump Off	Near Condensate Polishing Sys	Yes / No
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	/
2	Htr 6 Dump to Cond	Upstream of Valve	
3 / 26	Htr 2 Dump to Cond	Up/Downstream of Valve	/
4 / 27	Htr 4 Dump to Cond	Up/Downstream of Valve	/
5 / 28	Htr 5 Dump to Cond	Up/Downstream of Valve	/
29	Aux Stm to CRH Warm. (U/S of Check Vlv)	Platform Overhead	
30	Aux Stm to CRH Warm. (D/S of Check Vlv)	Platform Overhead	
31	Aux Steam to/from Unit 3 CRH	Platform Overhead	
32	Aux Steam to SSH	Platform Overhead	
33	Aux Steam Header Gray Valve	Platform Overhead	
54	HRH Line Drains	Below Turbine	
59	HRH Line Drains	Below Turbine	
55	CRH Line Drains - common line	Below Turbine	
56	CRH Line Drains - common line	Below Turbine	
57	CRH Line Drains - North	Below Turbine	
58	CRH Line Drains - South	Below Turbine	
60	MS Line Drain	Below Turbine	
61	MS Line Drain	Below Turbine	
	#1 Extr Drain Heat Soak Valve	Below Turbine	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
	Hotwell Make-Up Valves		
	Boiler Blow Down Valve		
	Valve SA 328 (turbine soak line)		
	Auxiliary Steam Supply to Seal Steam System		
	Valve 331 Auxiliary Steam from Cold RH		
	Reheat Attemperator		
	Heater #1 Continuous Vent		
	Heater #2 Continuous Vent		
	Heater #4 Continuous Vent		
	Heater #5 Continuous Vent		

ATTACHMENT G

Fuel Analyses - 50/50 Blend Pet Coke and Pittsburgh 8 Coal

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FUEL ANALYSES

Fuel	Unit #2				
	Jan. 27, 2004				
Time	1L & 2L 11:30	1L & 2L 12:30	1L & 2L 13:30	1L & 2L 14:30	1L & 2L 15:30
Proximate Analysis					
Moisture, wt% (±0.25)	7.24	7.81	7.64	7.04	6.96
Ash, wt% (±0.49)	5.45	6.25	5.54	5.68	5.83
Volatile, wt% (±1.0)	36.90	36.65	37.99	30.63	37.84
Fixed Carbon, wt% (±1.0)	50.41	49.29	48.83	56.66	49.38
Ultimate Analysis					
Carbon, wt% (±2.51)	75.62	73.42	72.95	73.90	76.37
Hydrogen, wt% (±0.30)	4.24	4.13	4.49	4.43	4.71
Nitrogen, wt% (±0.17)	1.50	1.58	1.39	1.44	1.45
Sulfur, wt% (±0.009)	4.68	5.61	6.73	6.19	3.51
Moisture, wt% (±0.25)	7.24	7.81	7.64	7.04	6.96
Ash, wt% (±0.49)	5.45	6.25	5.54	5.68	5.83
Oxygen, wt% (±2.51)	1.27	1.21	1.26	1.33	1.18
Higher Heating, Btu/lb (±107 Btu/lb)	13,361	13,457	13,371	13,391	13,567
Total Chlorine, wt% (±200 ug/g)	0.06	0.07	0.17	0.09	0.07
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000
Total Mercury, ug/g (±0.031 ug/g)	0.003	0.001	0.003	0.002	0.002
Total Lead, ug/g (±9 ug/g)	0.000	0.002	0.002	0.000	0.000
Moisture (oven), wt% (±1.0)	7.24	7.81	7.64	7.04	6.96
Ash elemental analysis					
SiO_2, wt% (±0.65)	0.55	0.51	0.58	0.66	0.71
Al_2O_3, wt% (±0.98)	58.89	63.91	60.76	62.89	67.44
Fe_2O_3, wt% (±1.44)	5.59	6.73	8.08	6.19	5.39
CaO, wt% (±4.74)	22.56	14.73	17.81	15.96	13.75
MgO, wt% (±1.25)	3.22	2.72	2.83	3.09	2.77
Na_2O, wt% (±3.70)	5.47	6.36	6.04	6.55	6.04
K_2O, wt% (±4.25)	3.28	4.54	3.32	4.01	3.35
Ti_2O, wt% (±1.52)	0.42	0.51	0.57	0.64	0.55
Particulate size distribution					
Particulate Left Mesh, 1/2", wt%	14.11	8.60	8.32	14.05	8.99
Particulate Left Mesh, 1/4", wt%	19.73	18.26	21.18	16.37	17.71
Particulate Left Mesh, #4, wt%	9.31	7.24	6.88	7.69	6.59
Particulate Left Mesh, #8, wt%	18.58	18.87	19.29	18.76	19.69
Particulate Left Mesh, #14, wt%	11.84	15.35	14.96	13.94	14.98
Particulate Left Mesh, #28, wt%	16.91	20.47	18.37	18.23	21.77
Particulate Left Mesh, #50, wt%	5.96	7.10	6.76	6.80	6.81
Particulate Left Mesh, #100, wt%	1.97	2.50	2.49	2.55	2.08
Bottom, wt%	0.75	0.59	0.76	0.69	0.41

The values obtained are averages of tests performed on two separate composite samples for each day and each hour

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FUEL ANALYSES

Fuel	Unit #2				
	Jan. 28, 2004				
Time	1L & 2L 10:00	1L & 2L 11:00	1L & 2L 12:00	1L & 2L 15:00	1L & 2L 16:00
Proximate Analysis					
Moisture, wt% (±0.25)	6.95	7.18	7.01	6.84	7.29
Ash, wt% (±0.49)	6.02	6.86	7.28	4.80	4.63
Volatile, wt% (±1.0)	38.02	36.95	33.35	37.82	37.96
Fixed Carbon, wt% (±1.0)	49.02	49.01	52.37	50.55	50.13
Ultimate Analysis					
Carbon, wt% (±2.51)	71.58	75.23	74.65	75.38	71.55
Hydrogen, wt% (±0.30)	4.73	5.00	4.37	4.26	4.67
Nitrogen, wt% (±0.17)	1.90	1.49	1.59	1.66	1.53
Sulfur, wt% (±0.009)	7.63	2.99	3.77	5.66	9.27
Moisture, wt% (±0.25)	6.95	7.18	7.01	6.84	7.29
Ash, wt% (±0.49)	6.02	6.86	7.28	4.80	4.63
Oxygen, wt% (±2.51)	1.21	1.27	1.34	1.40	1.07
Higher Heating, Btu/lb (±107 Btu/lb)	12,971	13,563	13,445	13,340	12,936
Total Chlorine, wt% (±200 ug/g)	0.17	0.15	0.06	0.08	0.11
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000
Total Mercury, ug/g (±0.031 ug/g)	0.002	0.003	0.006	0.003	0.003
Total Lead, ug/g (±9 ug/g)	0.006	0.003	0.001	0.000	0.000
Moisture (oven), wt% (±1.0)	6.95	7.18	7.01	6.84	7.29
Ash elemental analysis					
SiO_2, wt% (±0.65)	0.54	0.48	1.08	1.11	0.68
Al_2O_3, wt% (±0.98)	60.13	64.01	67.55	59.31	66.96
Fe_2O_3, wt% (±1.44)	9.82	7.52	6.47	6.30	6.35
CaO, wt% (±4.74)	15.25	13.67	13.85	20.82	12.21
MgO, wt% (±1.25)	2.97	2.75	2.54	2.88	2.41
Na_2O, wt% (±3.70)	6.05	6.49	4.65	5.39	7.53
K_2O, wt% (±4.25)	4.62	4.47	3.44	3.65	3.30
Ti_2O, wt% (±1.52)	0.62	0.60	0.43	0.51	0.55
Particulate size distribution					
Particulate Left Mesh, 1/2", wt%	11.11	14.84	15.29	9.15	8.96
Particulate Left Mesh, 1/4", wt%	15.79	18.35	17.06	17.18	15.09
Particulate Left Mesh, #4, wt%	7.47	7.89	7.05	6.09	6.82
Particulate Left Mesh, #8, wt%	19.14	17.13	16.65	18.20	18.65
Particulate Left Mesh, #14, wt%	15.67	12.63	15.04	15.47	18.06
Particulate Left Mesh, #28, wt%	20.37	17.67	17.87	23.57	22.00
Particulate Left Mesh, #50, wt%	6.71	7.53	7.01	5.92	6.65
Particulate Left Mesh, #100, wt%	2.17	2.56	2.56	3.55	2.07
Bottom, wt%	0.39	0.55	0.56	0.31	0.66

ATTACHMENT H

Limestone Analyses

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Test #2 Jan. 27, 2004					
Lab number	32077-01A	32077-02B	32077-03C	32077-04D	32077-05E	Average Values
Date	1/27/2004	1/27/2004	1/27/2004	1/27/2004	1/27/2004	
Time	11:30	12:30	13:30	14:30	15:30	
Compound Analysis						
$CaCO_3$, wt% (±0.41)	91.26	90.18	91.64	92.51	91.39	91.40
$MgCO_3$, wt% (±0.41)	3.17	3.03	2.97	2.82	2.74	2.95
Moisture (oven), wt% (±1.0)	0.53	0.50	0.52	0.47	0.53	0.51
Inerts (subtraction), wt% (±1.0)	5.03	6.29	4.87	4.20	5.33	5.15
Total Chlorine, wt% (±200 ug/g)	0.12	0.11	0.05	0.06	0.13	0.10
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.01	0.01	0.000	0.000	0.00
Particulate size distribution						
Particulate Left Mesh, #8, wt%	28.03	30.08	43.46	31.92	31.52	33.00
Particulate Left Mesh, #14, wt%	13.52	17.98	10.34	18.11	14.56	14.90
Particulate Left Mesh, #28, wt%	16.38	18.15	10.41	18.86	14.69	15.70
Particulate Left Mesh, #50, wt%	9.82	9.30	8.12	9.85	9.00	9.22
Particulate Left Mesh, #100, wt%	8.02	5.56	5.93	6.14	6.10	6.35
Particulate Left Mesh, #200, wt%	9.45	5.88	8.67	9.82	9.54	8.67
Particulate Left Mesh, #270, wt%	7.42	6.38	8.31	2.60	10.80	7.10
Bottom, wt%	5.86	4.54	3.58	1.56	2.72	3.65
Conversion Fraction	83.46	85.81	85.70	83.27	84.86	84.62

JEA Northside Unit2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Test #2 Jan. 28, 2004					
Lab number	32078-01A	32078-02B	32078-03C	32078-04D	32078-05E	Average Values
Date	1/28/2004	1/28/2004	1/28/2004	1/28/2004	1/28/2004	
Time	10:00	11:00	12:00	15:00	16:00	
Compound Analysis						
$CaCO_3$, wt% (±0.41)	84.83	87.93	86.04	87.88	85.28	86.39
$MgCO_3$, wt% (±0.41)	2.72	3.00	2.78	2.76	2.83	2.82
Moisture (oven), wt% (±1.0)	0.29	0.30	0.29	0.47	0.45	0.36
Inerts (subtraction), wt% (±1.0)	12.16	8.76	10.89	8.89	11.44	10.43
Total Chlorine, wt% (±200 ug/g)	0.03	0.20	0.07	0.05	0.05	0.08
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.001	0.002	0.004	0.002	0.004	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.000	0.01	0.000	0.000	0.00
Particulate size distribution						
Particulate Left Mesh, #8, wt%	24.94	28.39	44.25	40.85	39.33	35.55
Particulate Left Mesh, #14, wt%	13.20	11.48	17.67	17.64	15.00	15.00
Particulate Left Mesh, #28, wt%	13.65	12.24	13.38	12.98	13.21	13.09
Particulate Left Mesh, #50, wt%	11.79	12.47	5.92	5.91	14.44	10.11
Particulate Left Mesh, #100, wt%	13.90	15.21	6.54	6.53	6.03	9.64
Particulate Left Mesh, #200, wt%	20.58	12.54	5.33	5.32	6.15	9.98
Particulate Left Mesh, #270, wt%	0.00	4.89	7.83	7.82	2.82	4.67
Bottom, wt%	0.89	1.36	0.79	1.54	1.63	1.24
Conversion Fraction	80.51	79.40	79.03	78.70	77.81	79.09

ATTACHMENT I

Bed Ash Analyses

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Test #2 Jan. 27, 2004						
Lab Number	**32075-01**	**32075-02**	**32075-03**	**32075-04**	**32075-05**	**32075-06**	**32075-07**
Date	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**	**1/27/2004**
Time	**11:30**	**12:30**	**12:30**	**13:30**	**13:30**	**14:30**	**15:30**
Unburned carbon, wt%	0.01	0.02	0.06	0.01	0.08	0.03	0.02
Compound analysis							
CaSO4, wt% (±0.2)	24.90	15.60	18.90	27.60	20.40	26.40	15.90
Sulfur, wt% (±0.09)	0.94	0.62	0.70	1.04	0.77	1.07	0.65
Ash compound analysis							
SiO2, wt% (±0.65)	2.64	2.12	2.02	1.88	1.83	2.17	1.70
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	58.97	68.43	70.11	66.97	71.79	68.51	71.79
CaO, wt% (±4.74) (Not Part of Normalization)	20.74	21.38	21.34	21.06	20.96	21.12	21.30
MgO, wt% (±1.25)	32.45	24.42	23.16	24.31	21.90	24.52	22.29
Na2O, wt% (±3.70)	3.71	2.83	2.35	3.28	2.27	3.24	2.13
K2O, wt% (±4.25)	0.87	0.32	0.23	2.30	0.22	0.37	0.19
Vanadium, wt% (±1.0)	0.57	0.63	0.81	0.23	0.69	0.02	0.48
Nickel, wt% (±1.0)	0.80	1.24	1.32	1.03	1.30	1.18	1.43
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.01	0.02	0.02	0.02	0.02	0.02	0.02
K, wt% (±0.5 ug/g)	0.000	0.000	0.000	0.02	0.000	0.000	0.000
Particulate size distribution							
Particulate Left Mesh, 1/2", wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #8, wt%	2.37	21.04	4.25	4.48	4.00	8.04	8.44
Particulate Left Mesh, #14, wt%	5.11	7.15	6.15	6.46	6.19	6.22	6.49
Particulate Left Mesh, #28, wt%	18.24	18.53	18.58	16.70	16.96	18.01	17.69
Particulate Left Mesh, #48, wt%	26.34	19.79	23.28	20.91	23.68	22.58	21.92
Particulate Left Mesh, #100, wt%	34.15	18.11	26.15	25.22	27.26	25.91	24.19
Particulate Left Mesh, #200, wt%	11.99	15.07	19.21	25.64	20.96	17.98	20.22
Bottom, wt%	0.33	0.04	0.18	0.09	0.07	0.16	0.10

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	
Lab Number **Date** **Time**	**Average Values**
Unburned carbon, wt%	0.03
Compound analysis	
CaSO4, wt% (±0.2)	21.39
Sulfur, wt% (±0.09)	0.83
Ash compound analysis	
SiO2, wt% (±0.65)	2.05
SO3, wt% (±0.98)	0.00
Fe2O3, wt% (±1.44)	68.08
CaO, wt% (±4.74) (Not Part of Normalization)	21.13
MgO, wt% (±1.25)	24.72
Na2O, wt% (±3.70)	2.83
K2O, wt% (±4.25)	0.64
Vanadium, wt% (±1.0)	0.49
Nickel, wt% (±1.0)	1.18
Elemental analysis, AA	
Na, wt% (±0.5 ug/g)	0.02
K, wt% (±0.5 ug/g)	0.00
Particulate size distribution	
Particulate Left Mesh, 1/2", wt%	0.00
Particulate Left Mesh, #4, wt%	0.00
Particulate Left Mesh, #8, wt%	7.52
Particulate Left Mesh, #14, wt%	6.25
Particulate Left Mesh, #28, wt%	17.82
Particulate Left Mesh, #48, wt%	22.64
Particulate Left Mesh, #100, wt%	25.85
Particulate Left Mesh, #200, wt%	18.72
Bottom, wt%	0.14

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Test #2 Jan. 28, 2004						
Lab Number	**32076-01**	**32076-02**	**32076-03**	**32076-04**	**32076-05**	**32076-06**	**32076-07**
Date	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**	**1/28/2004**
Time	**10:00**	**11:00**	**12:00**	**12:00**	**15:00**	**16:00**	**16:00**
Unburned carbon, wt%	0.02	0.01	0.01	0.03	0.01	0.01	0.01
Compound analysis							
CaSO4, wt% (±0.2)	23.10	20.70	24	21.30	20.40	26.70	27.60
Sulfur, wt% (±0.09)	0.86	0.81	0.81	0.78	0.83	1.09	1.11
Ash compound analysis							
SiO2, wt% (±0.65)	1.01	1.97	1.99	1.85	1.78	2.04	1.76
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	72.10	69.20	69.34	72.60	67.67	70.82	70.61
CaO, wt% (±4.74) (Not Part of Normalization)	21.03	21.24	21.23	20.92	21.13	21.38	21.39
MgO, wt% (±1.25)	23.22	24.83	23.86	21.34	25.93	23.88	23.43
Na2O, wt% (±3.70)	2.01	2.26	2.52	2.11	2.54	1.78	2.10
K2O, wt% (±4.25)	0.20	0.33	0.36	0.25	0.30	0.21	0.30
Vanadium, wt% (±1.0)	0.05	0.49	0.88	0.67	0.65	0.02	0.60
Nickel, wt% (±1.0)	1.41	0.93	1.04	1.19	1.13	1.26	1.20
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.01	0.01	0.02	0.02	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Particulate size distribution							
Particulate Left Mesh, 1/2", wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #4, wt%	0.13	0.21	0.25	0.31	0.27	0.31	0.22
Particulate Left Mesh, #8, wt%	3.07	4.78	3.77	7.20	11.16	10.20	9.48
Particulate Left Mesh, #14, wt%	4.51	9.23	5.72	6.37	12.11	7.71	6.32
Particulate Left Mesh, #28, wt%	13.55	15.52	17.76	16.71	20.91	19.22	16.63
Particulate Left Mesh, #48, wt%	20.07	21.21	23.03	20.19	19.33	21.18	23.77
Particulate Left Mesh, #100, wt%	28.39	26.52	26.91	22.75	20.86	24.12	26.11
Particulate Left Mesh, #200, wt%	29.85	22.36	22.44	26.32	14.72	17.02	17.34
Bottom, wt%	0.09	0.17	0.13	0.15	0.11	0.14	0.13

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	
Lab Number Date Time	Average Values
Unburned carbon, wt%	0.01
Compound analysis	
CaSO4, wt% (±0.2)	23.40
Sulfur, wt% (±0.09)	0.90
Ash compound analysis	
SiO2, wt% (±0.65)	1.77
SO3, wt% (±0.98)	0.00
Fe2O3, wt% (±1.44)	70.33
CaO, wt% (±4.74) (Not Part of Normalization)	21.19
MgO, wt% (±1.25)	23.78
Na2O, wt% (±3.70)	2.19
K2O, wt% (±4.25)	0.28
Vanadium, wt% (±1.0)	0.48
Nickel, wt% (±1.0)	1.16
Elemental analysis, AA	
Na, wt% (±0.5 ug/g)	0.01
K, wt% (±0.5 ug/g)	0.00
Particulate size distribution	
Particulate Left Mesh, 1/2", wt%	0.00
Particulate Left Mesh, #4, wt%	0.24
Particulate Left Mesh, #8, wt%	7.09
Particulate Left Mesh, #14, wt%	7.42
Particulate Left Mesh, #28, wt%	17.19
Particulate Left Mesh, #48, wt%	21.25
Particulate Left Mesh, #100, wt%	25.09
Particulate Left Mesh, #200, wt%	21.44
Bottom, wt%	0.13

ATTACHMENT J

Fly Ash (Air Heater and PJFF) Analyses

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 27, 2004					
Lab Number	32073-05 (Air Heater)	32073-08 (Air Heater)	32073-10 (Air Heater)	32073-12 (Air Heater)	32073-16 (Air Heater)	Average Values
Time	11:30	12:30	13:30	14:30	15:30	
Unburned carbon, wt%	1.07	1.05	1.72	2.10	2.49	1.69
Compound analysis						
CaSO4, wt% (±0.2)	26.10	18.90	29.10	29.10	21.60	24.96
Sulfur, wt% (±0.09)	0.91	0.73	1.08	1.17	0.90	0.96
Ash compound analysis						
SiO2, wt% (±0.65)	1.03	0.59	0.85	0.81	0.74	0.80
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	73.84	74.81	72.33	72.49	72.53	73.20
CaO, wt% (±4.74) (Not Part of Norm	20.99	21.30	20.76	20.71	21.03	20.96
MgO, wt% (±1.25)	10.14	9.65	10.41	10.60	11.23	10.41
Na2O, wt% (±3.70)	7.76	7.84	8.84	8.92	8.27	8.33
K2O, wt% (±4.25)	5.36	5.36	5.74	6.06	5.51	5.61
Vanadium, wt% (±1.0)	0.76	0.65	0.76	0.02	0.63	0.57
Nickel, wt% (±1.0)	1.10	1.09	1.06	1.11	1.10	1.09
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.04	0.05	0.05	0.05	0.04	0.05
K, wt% (±0.5 ug/g)	0.02	0.02	0.02	0.02	0.02	0.02
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.33	0.08	0.08	0.00	0.00	0.10
Particulate Left Mesh, #14, wt%	0.17	0.17	0.06	0.46	0.04	0.18
Particulate Left Mesh, #28, wt%	0.12	0.13	0.10	0.29	0.17	0.16
Particulate Left Mesh, #48, wt%	0.21	0.15	0.07	0.29	0.00	0.14
Particulate Left Mesh, #100, wt%	0.33	0.45	0.35	0.75	0.37	0.45
Particulate Left Mesh, #270, wt%	79.58	76.31	75.81	72.30	70.32	74.86
Particulate Left Mesh, #325, wt%	5.16	6.01	5.92	6.58	6.24	5.98
Bottom, wt%	13.74	16.71	17.60	18.96	22.61	17.92

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 27, 2004				
Lab Number	32073-09 (Bag House)	32073-11 (Bag House)	32073-13 (Bag House)	32073-17 (Bag House)	Average Values
Time	12:30	13:30	14:30	15:30	
Unburned carbon, wt%	7.17	6.74	6.97	6.96	5.91
Compound analysis					
CaSO4, wt% (±0.2)	39.60	26.10	27.60	18.90	27.43
Sulfur, wt% (±0.09)	1.40	0.90	1.02	0.77	1.01
Ash compound analysis					
SiO2, wt% (±0.65)	0.32	0.20	0.25	0.19	0.35
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	70.32	74.15	76.04	74.40	73.62
CaO, wt% (±4.74) (Not Part of Norm	21.17	21.22	21.27	20.98	21.16
MgO, wt% (±1.25)	4.98	5.79	5.58	5.92	5.57
Na2O, wt% (±3.70)	13.75	10.81	9.24	10.64	11.11
K2O, wt% (±4.25)	9.75	7.76	6.29	7.55	7.84
Vanadium, wt% (±1.0)	0.44	0.86	2.48	0.85	1.16
Nickel, wt% (±1.0)	0.43	0.43	0.12	0.44	0.35
Elemental analysis, AA					
Na, wt% (±0.5 ug/g)	0.24	0.19	0.18	0.18	0.20
K, wt% (±0.5 ug/g)	0.18	0.15	0.14	0.14	0.15
Particulate size distribution					
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.09	0.00	0.00	0.17	0.07
Particulate Left Mesh, #28, wt%	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #48, wt%	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #100, wt%	0.10	0.00	0.00	0.25	0.09
Particulate Left Mesh, #270, wt%	19.11	19.72	19.33	20.35	19.63
Particulate Left Mesh, #325, wt%	25.25	29.75	26.11	22.34	25.86
Bottom, wt%	55.45	50.16	54.56	55.60	53.94

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 28, 2004					
Lab Number	32073-01 (Air Heater)	32073-03 (Air Heater)	32073-06 (Air Heater)	32073-14 (Air Heater)	32073-18 (Air Heater)	Average Values
Time	10:00	11:00	12:00	15:00	16:00	
Unburned carbon, wt%	1.73	1.38	1.79	1.61	1.85	1.67
Compound analysis						
CaSO4, wt% (±0.2)	39.60	29.40	33.30	26.70	27.90	31.38
Sulfur, wt% (±0.09)	1.52	1.09	1.26	1.19	1.04	1.22
Ash compound analysis						
SiO2, wt% (±0.65)	1.05	0.80	1.03	0.54	0.69	0.82
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	72.87	73.89	73.80	74.60	75.47	74.13
CaO, wt% (±4.74) (Not Part of Norm	21.00	21.10	21.10	21.05	21.07	21.07
MgO, wt% (±1.25)	11.04	10.26	10.19	10.36	10.33	10.44
Na2O, wt% (±3.70)	8.32	8.41	7.94	8.03	7.05	7.95
K2O, wt% (±4.25)	5.51	5.59	5.04	5.46	4.70	5.26
Vanadium, wt% (±1.0)	0.21	0.06	1.00	0.01	0.71	0.40
Nickel, wt% (±1.0)	1.00	1.00	1.01	1.00	1.04	1.01
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.05	0.05	0.05	0.05	0.04	0.05
K, wt% (±0.5 ug/g)	0.02	0.02	0.02	0.02	0.01	0.02
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.00	0.00	0.13	0.08	0.00	0.04
Particulate Left Mesh, #14, wt%	0.04	0.07	0.11	0.17	0.00	0.08
Particulate Left Mesh, #28, wt%	0.04	0.11	0.09	0.17	0.08	0.10
Particulate Left Mesh, #48, wt%	0.04	0.08	0.12	0.14	0.04	0.08
Particulate Left Mesh, #100, wt%	0.25	0.28	0.37	0.48	0.46	0.37
Particulate Left Mesh, #270, wt%	75.79	77.21	76.17	74.94	77.55	76.33
Particulate Left Mesh, #325, wt%	6.70	6.02	5.88	5.89	5.59	6.02
Bottom, wt%	16.77	16.23	17.13	18.14	15.87	16.83

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY FLYASH ANALYSES

Fly Ash	Test #2 Jan. 28, 2004					
Lab Number	32073-02 (Bag House)	32073-04 (Bag House)	32073-07 (Bag House)	32073-15 (Bag House)	32073-19 (Bag House)	Average Values
Time	10:00	11:00	12:00	15:00	16:00	
Unburned carbon, wt%	7.27	6.68	6.45	6.06	6.13	1.67
Compound analysis						
CaSO4, wt% (±0.2)	30.90	30.60	29.40	29.40	28.10	31.38
Sulfur, wt% (±0.09)	1.21	1.19	1.10	1.18	1.04	1.22
Ash compound analysis						
SiO2, wt% (±0.65)	0.37	0.43	0.32	0.33	0.35	0.82
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	71.78	73.66	72.59	73.43	76.35	74.13
CaO, wt% (±4.74) (Not Part of Norm	21.26	20.79	20.89	21.30	20.92	21.07
MgO, wt% (±1.25)	5.88	5.66	6.37	6.78	6.21	10.44
Na2O, wt% (±3.70)	12.28	11.14	11.68	10.82	9.71	7.95
K2O, wt% (±4.25)	8.48	7.94	7.90	7.37	6.63	5.26
Vanadium, wt% (±1.0)	0.81	0.78	0.73	0.84	0.46	0.40
Nickel, wt% (±1.0)	0.41	0.39	0.41	0.45	0.29	1.01
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.23	0.23	0.20	0.17	0.14	0.05
K, wt% (±0.5 ug/g)	0.17	0.18	0.15	0.12	0.10	0.02
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.04
Particulate Left Mesh, #14, wt%	0.01	0.04	0.00	0.00	0.07	0.08
Particulate Left Mesh, #28, wt%	0.00	0.00	0.00	0.00	0.00	0.10
Particulate Left Mesh, #48, wt%	0.00	0.00	0.00	0.00	0.00	0.08
Particulate Left Mesh, #100, wt%	0.31	0.92	0.00	0.00	0.39	0.37
Particulate Left Mesh, #270, wt%	18.92	19.93	17.12	20.02	19.13	76.33
Particulate Left Mesh, #325, wt%	26.72	20.38	30.02	21.26	24.25	6.02
Bottom, wt%	54.04	58.32	51.96	58.72	56.16	16.83

ATTACHMENT K

Ambient Data, Jan. 27, 2004 & Jan. 28, 2004

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
SUMMARY MET DATA

Date:	**January 27, 2004**	**January 28, 2004**
Start:	**1130 hours**	**1000 hours**
End:	**1530 hours**	**1600 hours**

Characteristic Being Measured	**Values Used in Efficiency Calculation**	
Dry Bulb Temperature, North / South, deg F	64.24	39.96
Count	482	482
Standard Deviation	3.7952	5.8027
Wet Bulb Temperature, North / South, deg F	57.96	43.19
Count	482	482
Standard Deviation	0.9488	6.8152
Atmospheric Pressure, in Hg	29.99	30.23
Atmospheric Pressure, psia	14.7	14.8
Count	5	6
Standard Deviation	0.00841	0.01025

ATTACHMENT L

Ambient Data, Jan. 29, 2004, Jan. 30, 2004, & Jan. 31, 2004

JEA Northside Unit 2
Test #2
50/50 Blend Pet Coke and Pittsburgh 8 Coal
MET DATA PARTIAL LOADS

DATE	TIME	WET BULB, DEG F	DRY BULB, DEG F	PRESSURE, PSIA	RELATIVE HUMIDITY, %
JAN. 31, 2004	12:00 AM	44	51	14.9	56.25
40% LOAD	1:00 AM	45	52	14.9	59.97
	2:00 AM	46	55	14.9	46.59
	3:00 AM	50	58	14.9	56.38
	4:00 AM	49	56	14.9	57.81
JAN. 29/30, 2004	10:00 PM	45	48	14.85	79.63
60% LOAD	11:00 PM	44	46	14.85	85.73
	12:00 PM	43	45	14.85	85.43
	1:00 AM	45	49	14.85	73.60
	2:00 AM	46	50	14.85	74.11
JAN. 29, 2004	3:00 PM	45.0	56	14.85	40.13
80% LOAD	4:00 PM	47.0	62	14.85	30.37
	5:00 PM	47.0	62	14.85	30.37
	6:00 PM	47.5	58	14.85	44.58
	7:00 PM	48.0	56	14.85	57.51

FIGURES

FIGURE 1 - GENERAL ARRANGEMENT PLAN, DRAWING NO. 3847-1-100, REV. 3

FIGURE 2 - GENERAL ARRANGEMENT ELEVATION, DRAWING NO. 3847-1-101, REV. 3

FIGURE 3 - FABRIC FILTER EAST END ELEVATION, DRAWING NO. 3847-9-268, REV. 2

FIGURE 4 - GENERAL ARRANGEMENT UNIT 2 ISO VIEW (RIGHT SIDE), DRAWING NO. 43-7587-5-53

FIGURE 5 - GENERAL ARRANGEMENT UNIT 2 FRONT ELEVATION VIEW A-A, DRAWING NO. 43-7587-5-50, REV. C

FIGURE 6 - GENERAL ARRANGEMENT UNIT 2 SIDE ELEVATION, DRAWING NO. 43-7587-5-51, REV. C

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3847-1-100

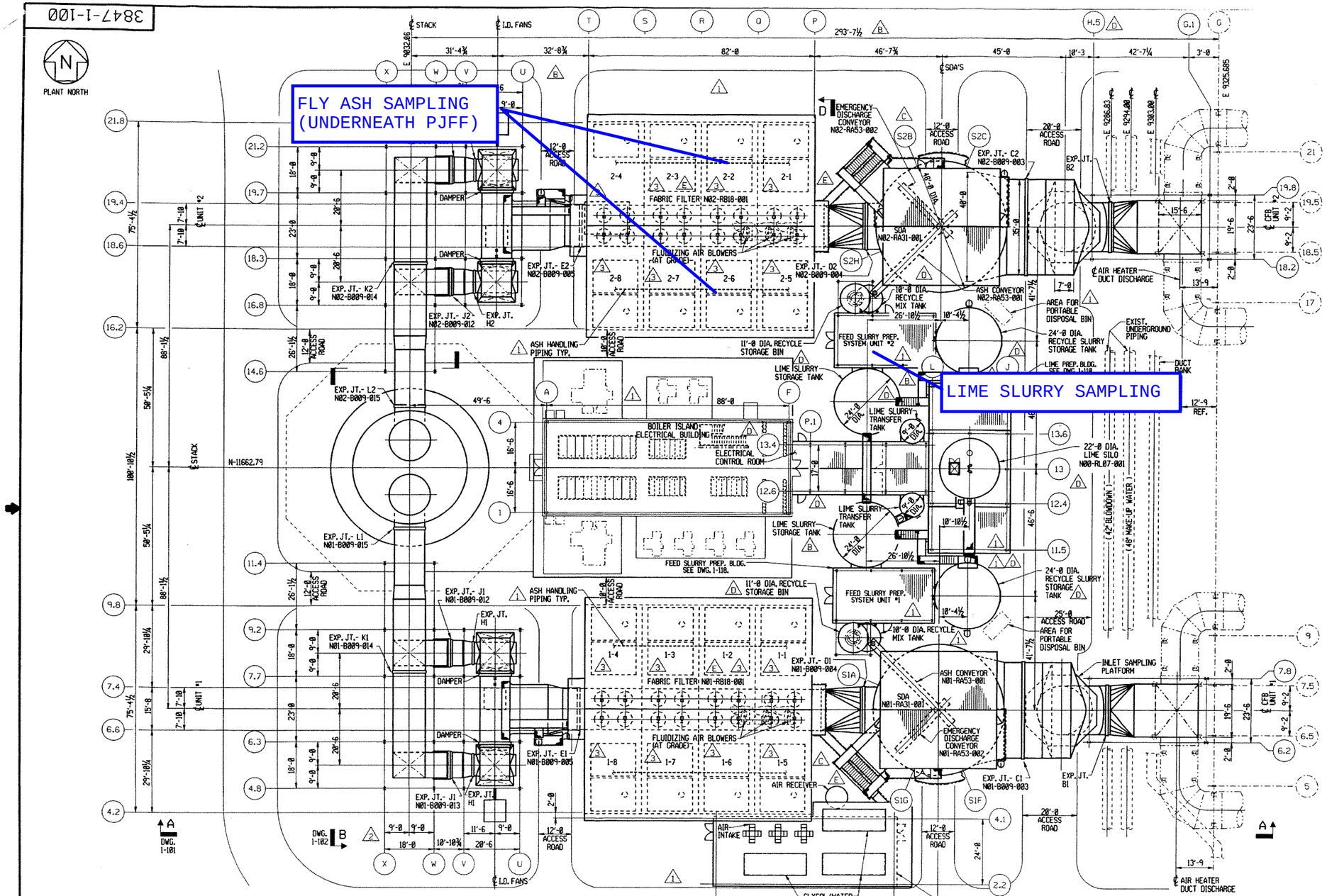

FIGURE 1

NOTES:

1. FOR COMPLETE COLUMN DESIGNATIONS & LOCATIONS SEE DWG. 9-001.
2. FOR TANK LOCATIONS SEE DWG. 9-003.

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NO.	REVISION	DWN.	CHK.	DATE
B	REVISED DIMENSIONS & LAYOUT ABS PREP AREA	RK	BN	8-28-99
C	MOVED STAIR TOWER	RK	BN	2-15-99
D	REV. TANK & COL. DESIGNATIONS	RWK		1-9-00
E	MOVED STAIR TOWER, REVISED EQUIP. NO'S.	RK	BN	2-4-00
R	DRAWING UPDATED AND CHECKED.	RK	DLM	3-1-00

NO.	REVISION	DWN.	CHK.	DATE
1	ADD ELECT BLDG & ASH HANDLING REF	CC		4-27-00
2	ADD OUT DUCT SUPT INFO, INC CUST COMMENT, ADD EXP JT TAGS	CC	BN	7-12-00
3	REV F.F. COMPARTMENT NUMBERING	CC		8-15-00

ISSUE RECORD

REV.	DATE	TO	FOR
2	7-14-00	WAPC & WATKINS	CONSTRUCTION
2	8-4-00	INSULATOR	BIOS
3	9-20-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
E	2-7-00	FOSTER WHEELER	INFORMATION
B	3-1-00	FABRICATOR	FAB INFO
B	4-3-00	FABRICATOR	BID INFO
I	4-28-00	FOSTER WHEELER	INFO
D	7-14-00	FOSTER WHEELER	INFO

REV.	DATE	TO	FOR
A	10-1-99	FOSTER WHEELER	INFORMATION
B	10-29-99	FOSTER WHEELER	INFORMATION
C	12-15-99	NELS	MODEL BID
D	1-11-00	NELS	MODEL FAB
D	1-14-00	FABRICATOR	BID INFO.

DRN. BY	RK	DATE	9-9-99
CHKD. BY	DLM	DATE	2-29-00
APPVD. BY	GG	DATE	3-1-00
SCALE	1/16"=1'-0		
CERTIFIED BY:		DATE:	

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

GENERAL ARRANGEMENT PLAN

Wheelabrator Air Pollution Control
A Waste Management Company

DRAWING NUMBER 3847-1-100 REV. NO. 3

B&V DWG. #62.0200.05-C0005
GEM CODE #N01-RA31-001, N02-RA31-001
N01-RB18-001 THRU 008, N02-RB18-001 THRU 008

m:\contract\3847\cad\38471100.dgn

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LAST PLOTTED BY: RK

P062713.62.0200.05-C0005 St:NE 11/21/00 MM-01186

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3847-1-101

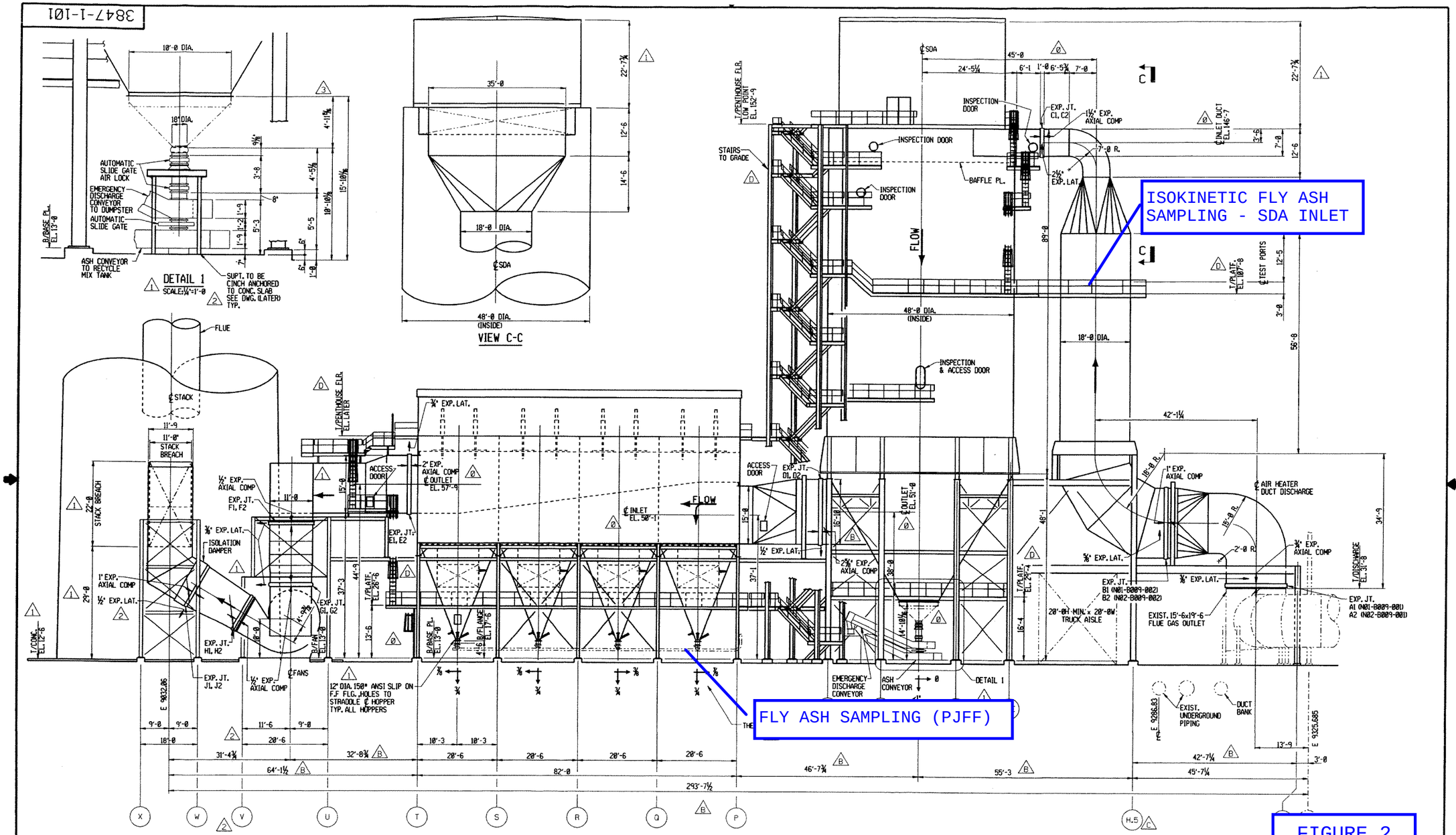

FIGURE 2

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B&V DWG. #62.0200.05-C0006
GEM CODE #N01-RA31-001, N02-RA31-001
N01-RB18-001 THRU 008, N02-RB18-001 THRU 008

NO.	REVISION	DRN.	CHK.	DATE
B	REVISED DIMENSIONS & TRUCK AISLE	BN	RK	8-26-99
C	REVISED COLUMN DESIGNATION	BN	RK	1-4-00
D	REVISED ACCESS ADDED ELEVATIONS	BN	RK	2-4-00
E	DWG UPDATED AND CHECKED	BN	RWK	3-1-00
F	REV DUCT DIM & ADD DETAIL 1	DM	CC	

NO.	REVISION	DRN.	CHK.	DATE
1	REVISED OUTLET DUCT & GENERAL REV.		RWK	4-27-00
2	ADD OUTLET DUCT SUPT INFO & INCORPORATE CUSTOMER COMMENT	BN	CC	7-12-00
3	ADD EXP MOVEMENTS AND EXP JT TAGS	BN	CC	7-19-00
3	REV. DIMENSIONS AT DETAIL 1			

ISSUE RECORD

REV.	DATE	TO	FOR
3	8-4-00	INSULATOR	BIDS
3	9-20-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
D	2-7-00	FOSTER WHEELER	INFORMATION
E	3-1-00	FABRICATOR	FAB INFO
1	4-28-00	FOSTER WHEELER	INFO
2	7-14-00	FOSTER WHEELER	INFO
2	7-14-00	WARC & WATKINS	CONSTRUCTION

REV.	DATE	TO	FOR
A	10-1-99	FOSTER WHEELER	INFORMATION
B	10-29-99	FOSTER WHEELER	INFORMATION
B	12-15-99	NELS	MODEL BID
B	1-11-00	NELS	MODEL FAB
C	1-14-00	FABRICATOR	BID INFO.

DRN. BY RK DATE 9-9-99
CHKD. BY DLM DATE 2-29-00
APPVD. BY GG DATE 3-1-00
SCALE 3/32"=1'-0
CERTIFIED
BY: DATE:

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

GENERAL ARRANGEMENT
ELEVATION

Wheelabrator Air Pollution Control
A Waste Management Company

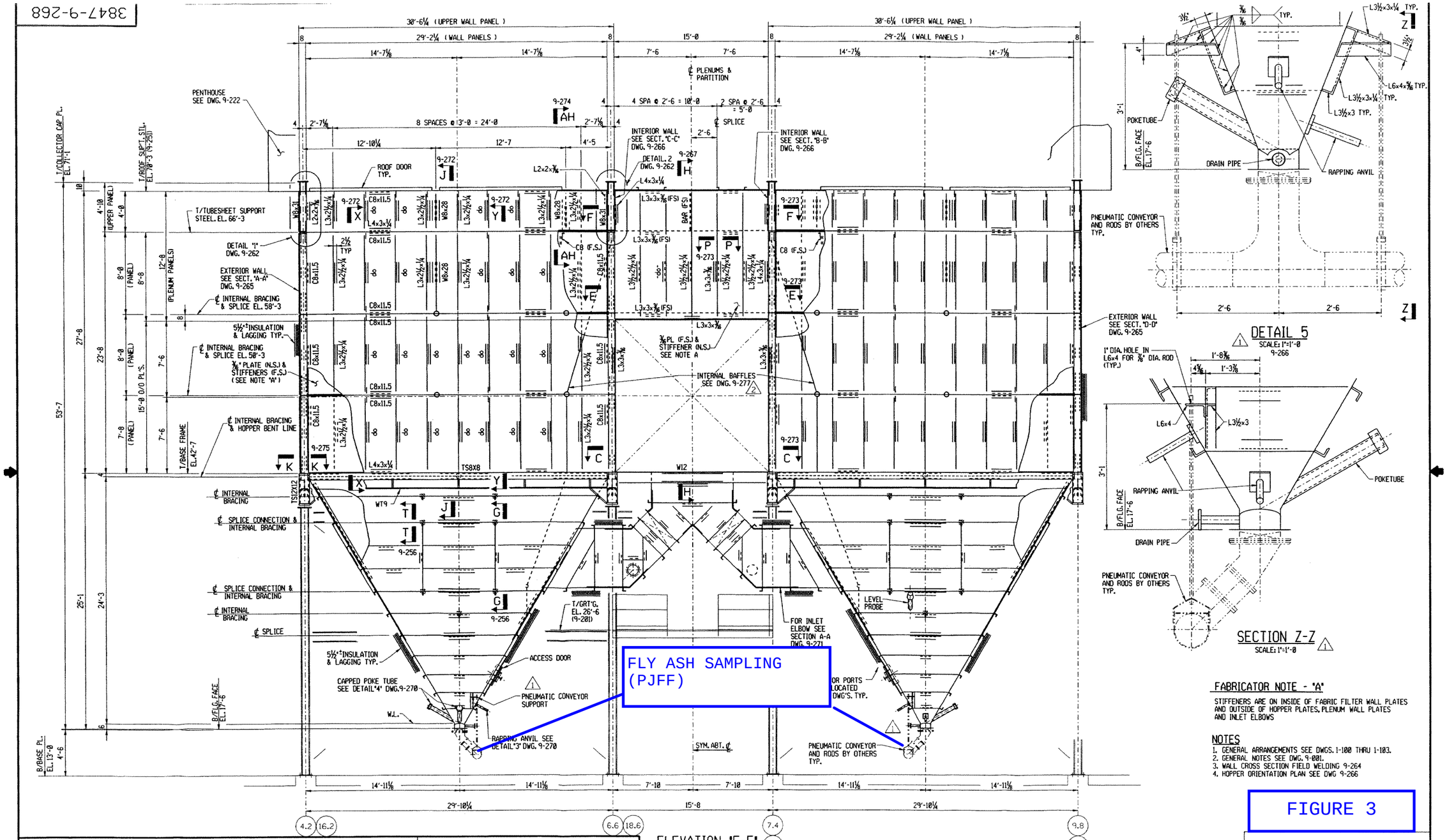
DRAWING NUMBER 3847-1-101
REV. NO. 3

m:\contract\3847\cad\3847101.dgn

PLOT DATE: 15 SEP 2000 13:28:26
LAST PLOTTED BY: RK

3847-9-268

DWG40998 03-MAR-2004 14:42:45



FLY ASH SAMPLING (PJFF)

ELEVATION "E-E"

(LOOKING WEST)
9-250 THRU 9-255

DETAIL 5

SCALE: 1"=1'-0
9-266

SECTION Z-Z

SCALE: 1"=1'-0

FABRICATOR NOTE - "A"

STIFFENERS ARE ON INSIDE OF FABRIC FILTER WALL PLATES AND OUTSIDE OF HOPPER PLATES, PLENUM WALL PLATES AND INLET ELBOWS

NOTES

1. GENERAL ARRANGEMENTS SEE DWGS. 1-100 THRU 1-103.
2. GENERAL NOTES SEE DWG. 9-001.
3. WALL CROSS SECTION FIELD WELDING 9-264
4. HOPPER ORIENTATION PLAN SEE DWG 9-266

FIGURE 3

GEM CODE *N01-RB18-001 THRU 008
N02-RB18-001 THRU 008

B&V DWG NO: 62.0200.05-C0064

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NO.	REVISION	DWN.	CHK.	DATE
0	DRAWING CHECKED	GL	WCC	2-24-00
1	ADD SUPTS FOR PNEUMATIC CONV., DET 5 & SECT Z-Z	CC	BW	5-22-00
2	REMOVED HOLD @ BAFFLE PL'S.	RK		8-15-00

NO.	REVISION	DWN.	CHK.	DATE

ISSUE RECORD

REV.	DATE	TO	FOR
2	9-13-00	WAPC & WATKINS	CONSTRUCTION
2	9-23-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
A	1-14-00	FABRICATOR	BID
0	3-1-00	MCKAMISH	FAB
0	4-20-00	FOSTER WHEELER	INFO
1	5-22-00	MCKAMISH	INFO
1	8-4-00	INSULATOR	BID

DRN. BY	J.H.	DATE	12-16-99
CHKD. BY	W.C.C.	DATE	2-24-00
APPVD. BY	K.R.	DATE	3-1-00
SCALE	¼" = 1'-0		
CERTIFIED BY:		DATE:	

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

FABRIC FILTER
EAST END
ELEVATION E-E

Wheelabrator Air Pollution Control
A Waste Management Company

DRAWING NUMBER 3847-9-268
REV. NO. 2

m:\contract\3847\cad\38479268.dgn

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LAST PLOTTED BY: RK

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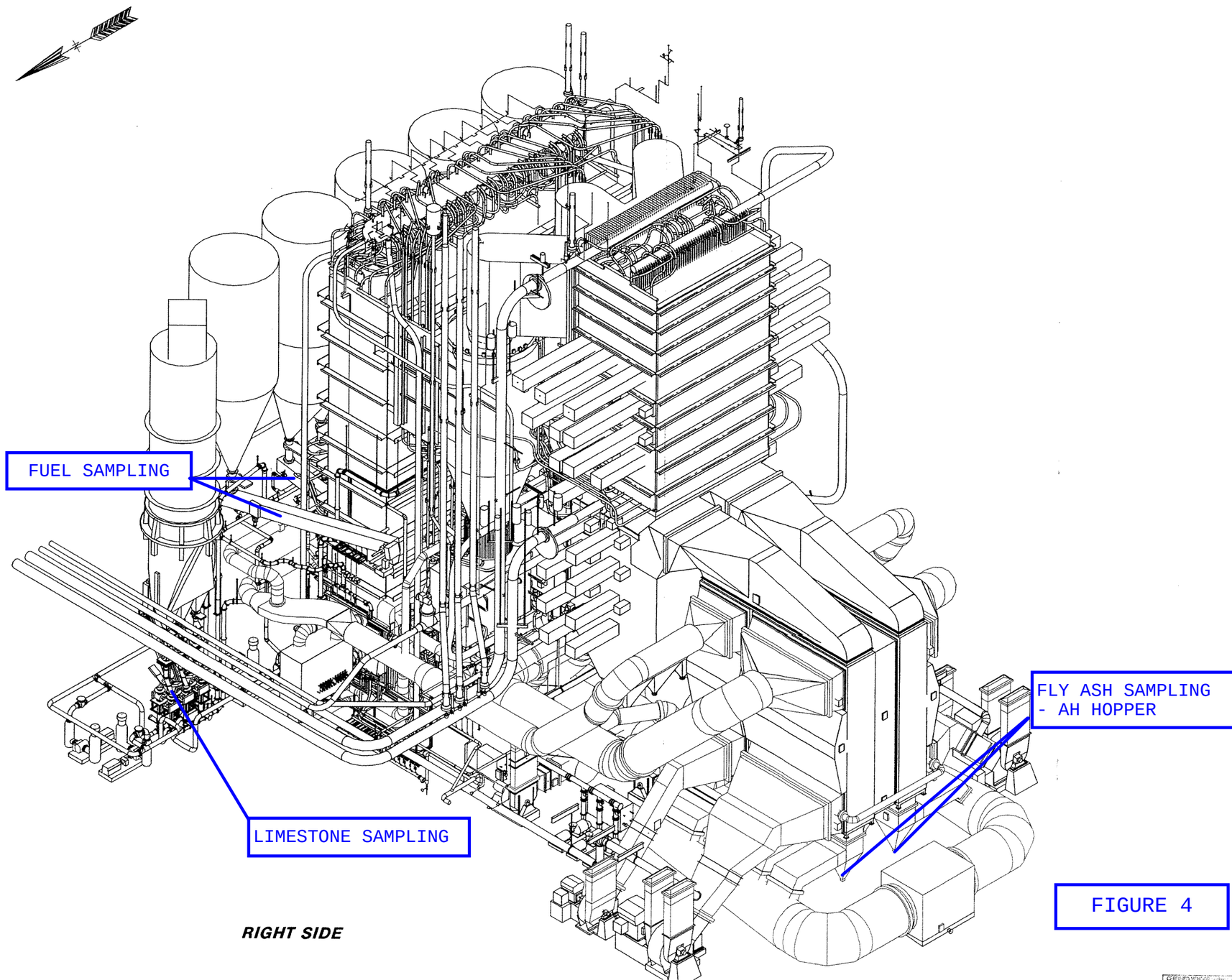

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2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. FOR ADDITIONAL NOTES & REFERENCE DRAWINGS SEE DRAWING 43-7587-5-50

B&V Dwg No. 62.3401.05-C0012

REV	DATE	BY	DESCRIPTION
C	5-23-00	JHM	UPDATED DRAWING
B	5-26-99	JHM	DESIGN UPDATE
A	5-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
ISO VIEW (RIGHT SIDE)

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.
B&V Drawing No.: 62.3401.05-C0012

DRAWING NUMBER: 43-7587-5-53 | SCALE: | REVISION: C

DRAWN BY	JHM	3-16-99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

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CERTIFIED VENDOR DRAWING
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REVISE ONLY IN PDMS

FIGURE 4

P062713.62.3401.05-C0012 St:NE 08/04/00 MM-00739

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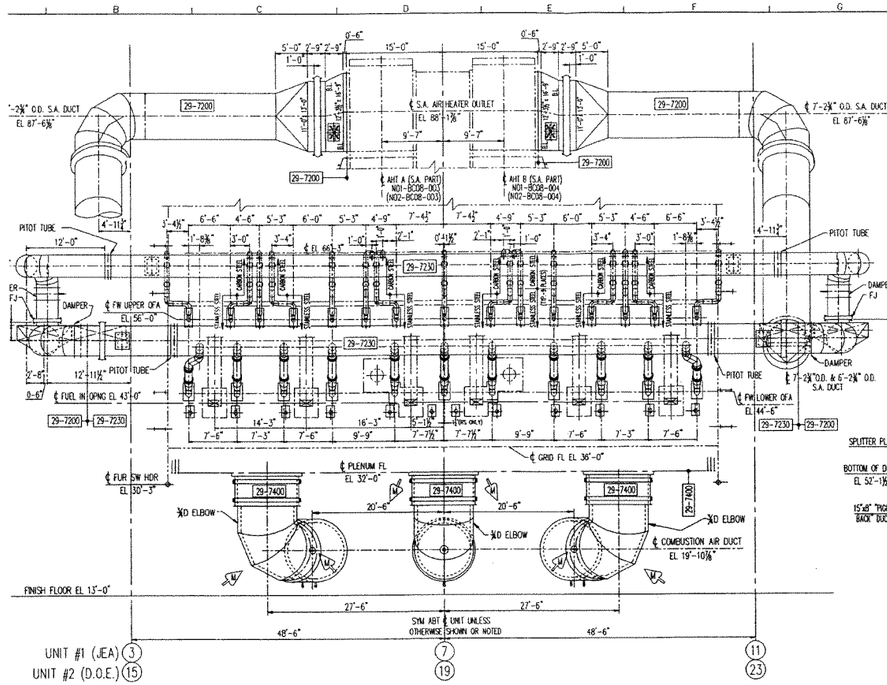

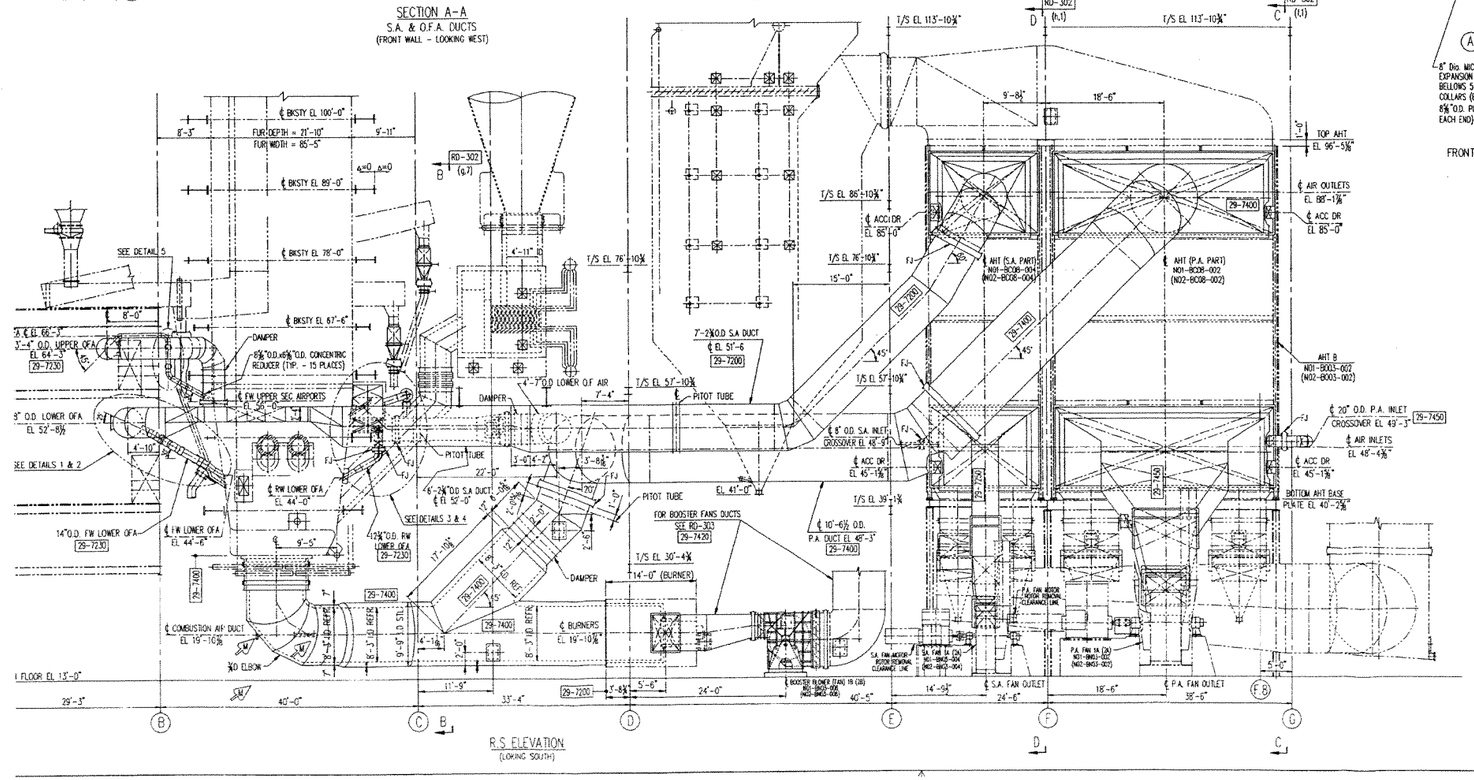

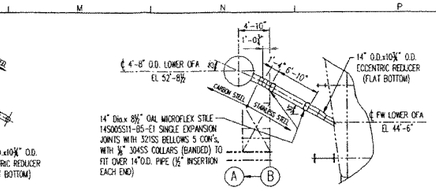

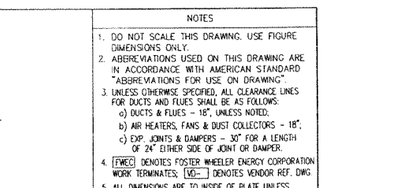

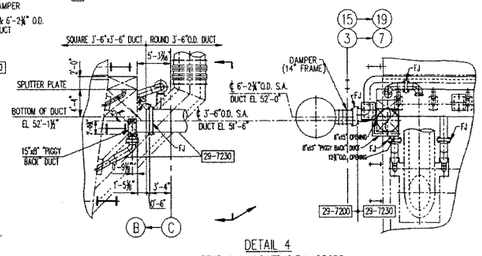

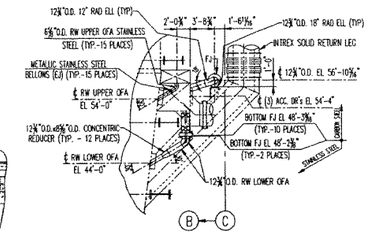

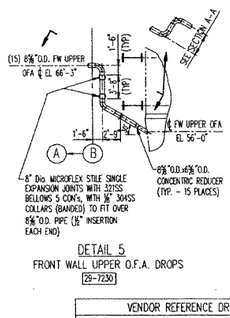

NOTES

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2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. UNLESS OTHERWISE SPECIFIED, ALL CLEARANCE LINES FOR DUCTS AND FLUES SHALL BE AS FOLLOWS:
   a) DUCTS & FLUES - 18", UNLESS NOTED.
   b) AIR HEATERS, FANS & DUST COLLECTORS - 18".
   c) EXP. JOINTS & DAMPERS - 30" FOR A LENGTH OF 24" EITHER SIDE OF JOINT OR DAMPER.
4. FWEC DENOTES FOSTER WHEELER ENERGY CORPORATION WORK TERMINATES; VO- DENOTES VENDOR REF. DWG.
5. ALL DIMENSIONS ARE TO INSIDE OF PLATE UNLESS OTHERWISE NOTED.
6. ALL ROUND MITERED DUCT ELBOWS RADIUS EQUAL ONE DIAMETR OF DUCT OR FLUE (R=1D) UNLESS OTHERWISE NOTED.
7. FOR PLATE THICKNESS, PLATE MATERIAL & EXPANSION JOINT INFORMATION REFER TO FLUE & DUCT ASSEMBLY DRAWINGS BEGINNING WITH DRAWING 43-7587-5-310, WHEN ISSUED.
8. ALL ACCESS DOORS ARE 18"x24"(H).

FWEC REFERENCE DRAWINGS

1. GENERAL ARRANGEMENT CROSS SECTION	43-7587-5-20
2. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS A-A & B-B	43-7587-5-21
3. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS C-C & D-D	43-7587-5-22
4. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS PLAN VIEW	43-7587-5-301
5. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS SECTIONS B-B, C-C, D-D AND VIEWS	43-7587-5-302
6. ARRANGEMENT AUXILLIARY EQUIPMENT BURNER BOOSTER BLOWERS (FANS) LAYOUT. PLAN VIEW & SECTIONS	43-7587-5-303
7. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEW @ AHT TOP, R.S. ELEVATION AND VIEWS A-A & B-B	43-7587-5-304
8. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEWS C-C & @ AHT SUPPORT LEVEL AND DETAILS	43-7587-5-305
9. INSTRUMENT LOCATION PLANS	43-7587-5-6400 THRU 6404, 6406, 6408, 6411, 6413 THRU 6419

VENDOR REFERENCE DRAWINGS

1. KENTUBE ENGINEERED PRODUCTS L.L.C.
   TUBULAR AIR HEATER - WP # AH001
   - GENERAL ARRANGEMENT 99091-1
   - AHT SUPPORT LAYOUT & LOAD DIAGRAM 99091-2
2. PEABODY ENGINEERING START-UP DUCT BURNER - WP # BRN01
   - GENERAL ARRANGEMENT D-326001
   - COMBUSTION AIR INLET & DUCT BURNER OUTLET FLANGE DETAILS C-326004
   BURNER PIPE RACK - WP # BRN01
   - HEADER PIPE RACK GENERAL ARRANGEMENT D-LATER
   - LOCAL PIPE RACK GENERAL ARRANGEMENT D-326036
3. CHICAGO BLOWER CORPORATION START-UP BURNER BOOSTER FAN - WP # BRN01
   - GENERAL ARRANGEMENT (CW) FAN "C" 19-0-2492-01
   - GENERAL ARRANGEMENT (CCW) FAN "A" 19-0-2492-02
   - GENERAL ARRANGEMENT (CW) FAN "B" 19-0-2493
4. ABBI GARDEN CITY FAN
   SECONDARY AIR FAN - WP # FAN01
   - GENERAL ARRANGEMENT (CCW) 43092
   - GENERAL ARRANGEMENT (CW) 43093
5. ABBI GARDEN CITY FAN
   PRIMARY AIR FAN - WP # FAN01
   - GENERAL ARRANGEMENT (CCW) 43104
   - GENERAL ARRANGEMENT (CW) 43105
6. TECO-WESTINGHOUSE MOTOR COMPANY
   PRIMARY AIR FAN MOTOR - WP # MTR01
   - GENERAL ARRANGEMENT (CCW) C2534AA
   - GENERAL ARRANGEMENT (CW) C2534AB
7. TECO-WESTINGHOUSE MOTOR COMPANY
   SECONDARY AIR FAN MOTOR - WP # MTR01
   - GENERAL ARRANGEMENT C8550AA
8. LUBE-POWER, INC.
   P. A. FAN & MOTOR LUBRICATION SYSTEM SKID - WP # FAN01
   - GENERAL ASSEMBLY LP1354-A

MCH	DATE	BY	DESCRIPTION
M	03-26-01	AGS	REVISED LOCATION OF RIGHT AND LEFT SIGHT GLASS PORTS AT COMBUSTION AIR DUCTS @ SECTION A-A AND RIGHT SIDE ELEVATION.
L	02-28-01	AGS	DELETED "HOLD" FROM COMBUSTION AIR DUCT AND ADDED (2) ACCESS DOOR AND DIMENSIONS TO IT AS SHOWN AT RIGHT SIDE ELEVATION.
K	01-12-00	AGS	ADDED VENDOR REFERENCE DRAWINGS VRD-8.
J	06-22-00	AGS	REVISED TAG NUMBER FOR BURNER BOOSTER FAN "B", S.A. & P.A. FANS @ R.S. ELEVATION. ADDED FWEC REFERENCE DRAWINGS RD-9. REVISED VENDOR REFERENCE DRAWINGS VRD-3. ADDED VENDOR REFERENCE DRAWINGS. PEABODY BURNER PIPE RACKS DRAWINGS. UPDATED BOOSTER BLOWER INLET & OUTLET DUCTING AND BOOSTER BLOWERS PICTURES ACCORDING TO ACTUAL PURCHASED FANS. PURCHASED FANS @ R.S. ELEVATION. REVISED DIMENSION 26'-0" (WAS 24'-0") FOR BOOSTER BLOWER "B" FROM ℄ TO COLUMN "D" @ R.S. ELEVATION.
H	03-08-00	AGS	REVISED SOME (8 of 13) FRONT WALL UPPER O.F.A. DROPS (29-7230) O.D. PIPE AT R.S. ELEVATION, SECTION A-A & DETAIL 5.
G	02-08-00	AGS	CORRECTED FWOSA (AG) Rev.1 FOR Pnl. 8 Sec. AHT PARTS.
F	02-04-00	AGS	ADDED P.A. FAN MOTOR VENDOR REFERENCE DRAWINGS. REVISED START-UP BURNER BOOSTER FAN VENDOR REFERENCE DRAWING NUMBERS. DELETED "HOLD" @ P.A. & S.A. FAN MOTORS & REVISED P.A. & S.A. FAN MOTORS PICTURES AT RIGHT SIDE ELEVATION. ADDED PART No.'S FOR DUCTS.
E	11-24-99	AGS	ADDED NOTE 8. REVISED DIMENSION BETWEEN COLUMNS "1.5" & "C": 5'-0" (WAS 6'-0") @ R.S. ELEVATION. ADDED P.A. FAN VENDOR REFERENCE DRAWING NUMBERS. REVISED P.A. FAN PICTURE TO INCLUDE ACTUAL PURCHASED FAN @ R.S. ELEVATION. ADDED DETAIL 5. REVISED SIZE OF FW UPPER OFA DROPS (EXPANSION JOINT). TOOK SECTION WITH (7) TWO METALLIC BELLOWS (WAS (1) ONE FABRIC EJ) @ R.S. ELEVATION & SECTION A-A.
D	11-08-99	AGS	ADDED VENDOR REFERENCE DRAWINGS. ADDED FWEC REFERENCE DRAWINGS No.'S 5, 7 & 8. ADDED S.A. DUCTS TO INTREX SOLID RETURN LEG. ADDED P.A. & S.A. AHT INLET DUCT CROSSOVERS. REVISED SIZE OF FW LOWER OFA DROPS: 14"O.D. (WAS 16" O.D.). ADDED TRANSITIONS. SHEET 8. REVISED DIMENSIONS AND ADDED DETAILS INFO WHERE INDICATED ON SHEET 8.
C	06-25-99	AGS	REVISED @ STIFFENERS TO TRACK COMMENTS (ADDED GRADE INFO, NOTES, & BMC INFO). REVISED S.A. & P.A. DUCTS AS SHOWN.
B	6/7/98	AP	ADDED FDJ AND SEC. AIR FANS AND DUCTS TO AIR HEATER. ADDED PRIMARY AIR FLOW MEASUREMENT DEVICES AT SEC. AND QT. AIR DUCTS. REVISED QT. AIR DUCTS AT BOILER FRONT AND REAR WALLS. DRAWING ISSUED FOR START AND PERFORMANCE REVIEW.
A	5/10/98	AP	ISSUED FOR PRIMARY AND SECARD DUCT LOAD CALCULATIONS ONLY.

REVISIONS

FOSTER WHEELER ENERGY CORPORATION
STEAM GENERATOR
ARRANGEMENT OF AUXILIARY EQUIPMENT
SECONDARY & PRIMARY AIR DUCTS
R.S. ELEVATION, SECTION A-A AND DETAILS 1 THRU 4

JEA JACKSONVILLE, FLORIDA
NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.: N01-BN, N02-BN
B&V Drawing No.: 62.3401.05-C0046

DRAWING NUMBER: 43-7587-5-300
SCALE: 3/8" = 1'-0"
REVISION: M

DRAWN BY	AF	4/8/99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

THIS DRAWING IS THE PROPERTY OF THE FOSTER WHEELER ENERGY CORPORATION PERRYVILLE, N.J.

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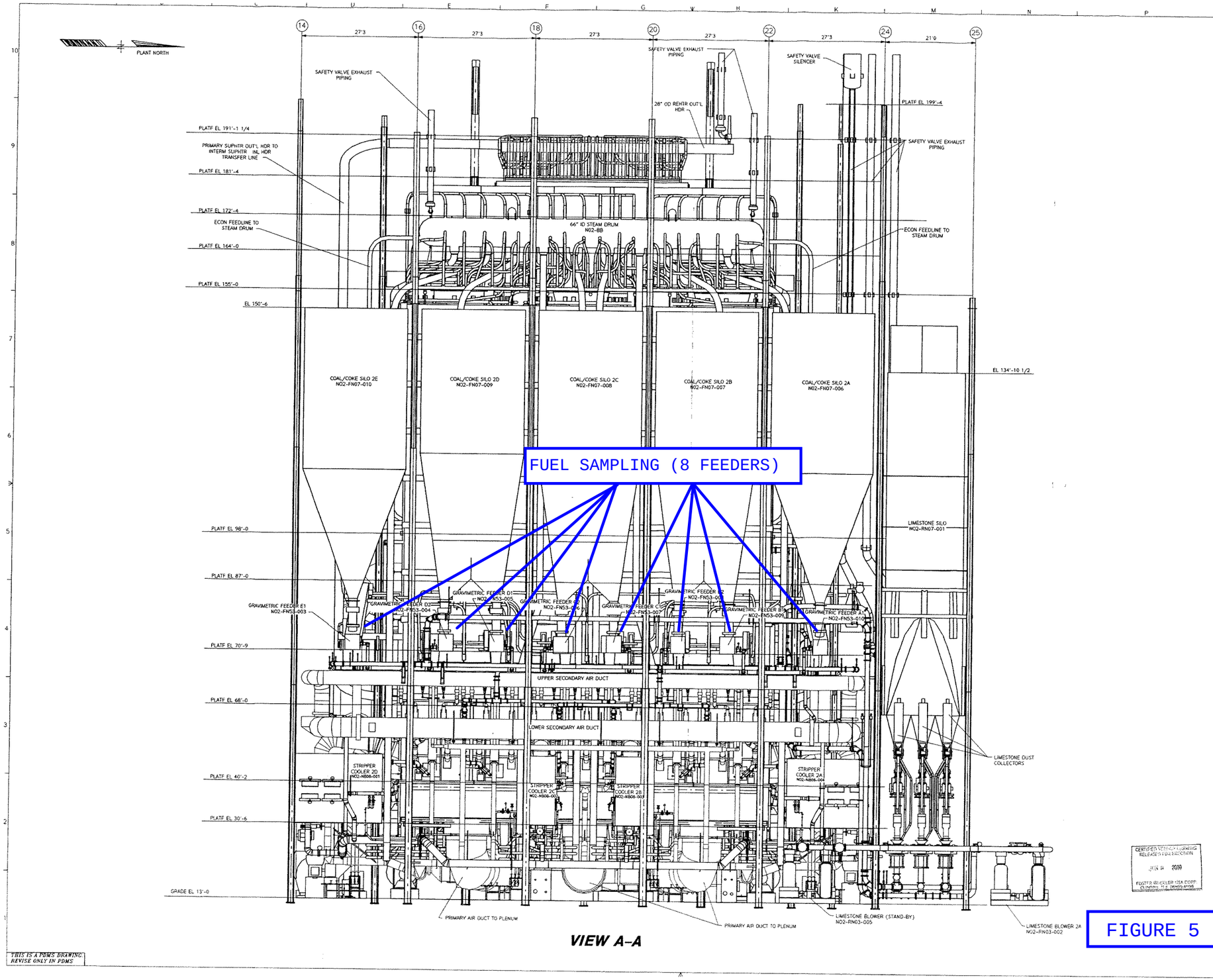

NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".

REFERENCE DRAWINGS

GENERAL ARRANGEMENT CROSS SECTION	43-7587-5-20
GENERAL ARRANGEMENT LONGITUDINAL SECTIONS A-A & B-B	43-7587-5-21
GENERAL ARRANGEMENT LONGITUDINAL SECTIONS C-C & D-D	43-7587-5-22
PENTHOUSE RISERS & TRANSFER TUBES	43-7587-5-170
SECTIONS & DETAILS IN HRA	43-7587-5-160
CYCLONE SECTIONAL ARRANGEMENT	43-7587-5-200
INTERMEDIATE SUPERHEATER 1 ARRANGEMENT	43-7587-5-210
INTERMEDIATE SUPERHEATER 2 ARRANGEMENT	43-7587-5-211
INTERMEDIATE SUPERHEATER 3 ARRANGEMENT	43-7587-5-212
ARRANGEMENT OF AUXILIARY EQUIPMENT	43-7587-5-300
INTREX GENERAL ARRANGEMENT	43-7587-5-380
DOWNCOMER ARRANGEMENT AND DETAILS	43-7587-5-400
FURNACE FEEDER ARRANGEMENT	43-7587-5-405
TRANSFER LINES TO LOWER CYCLONE INLET HEADERS	43-7587-5-410
SAFETY VALVE EXHAUST PIPING ARRANGEMENT	43-7587-5-416
STRIPPER COOLER ARRANGEMENT	43-7587-5-430
ARRANGEMENT OF 66" ID DRUM	43-7587-5-480
KEY PLAN BOILER & AIR HEATER	43-7587-5-9001

B&V Dwg No: 62.3401.05-C0057

REV	DATE	BY	DESCRIPTION
C	5-16-00	JHM	UPDATED DRAWING AND ADDED EQUIPMENT DESIGNATIONS
B	5-26-99	JHM	DESIGN UPDATE
A	3-30-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
FRONT ELEVATION
VIEW A-A

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No:
B&V Drawing No.: 62.3401.05-C0057

DRAWING NUMBER: 43-7587-5-50
SCALE:
REVISION: C

DRAWN BY	WDJ	3-16-99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

FOSTER WHEELER ENERGY CORPORATION

CERTIFIED NEW CONSTRUCTION RELEASED FOR EXECUTION JUN 14 2000 FOSTER WHEELER USA CORP. CLINTON, N.J. DENVER, COLO.

FIGURE 5

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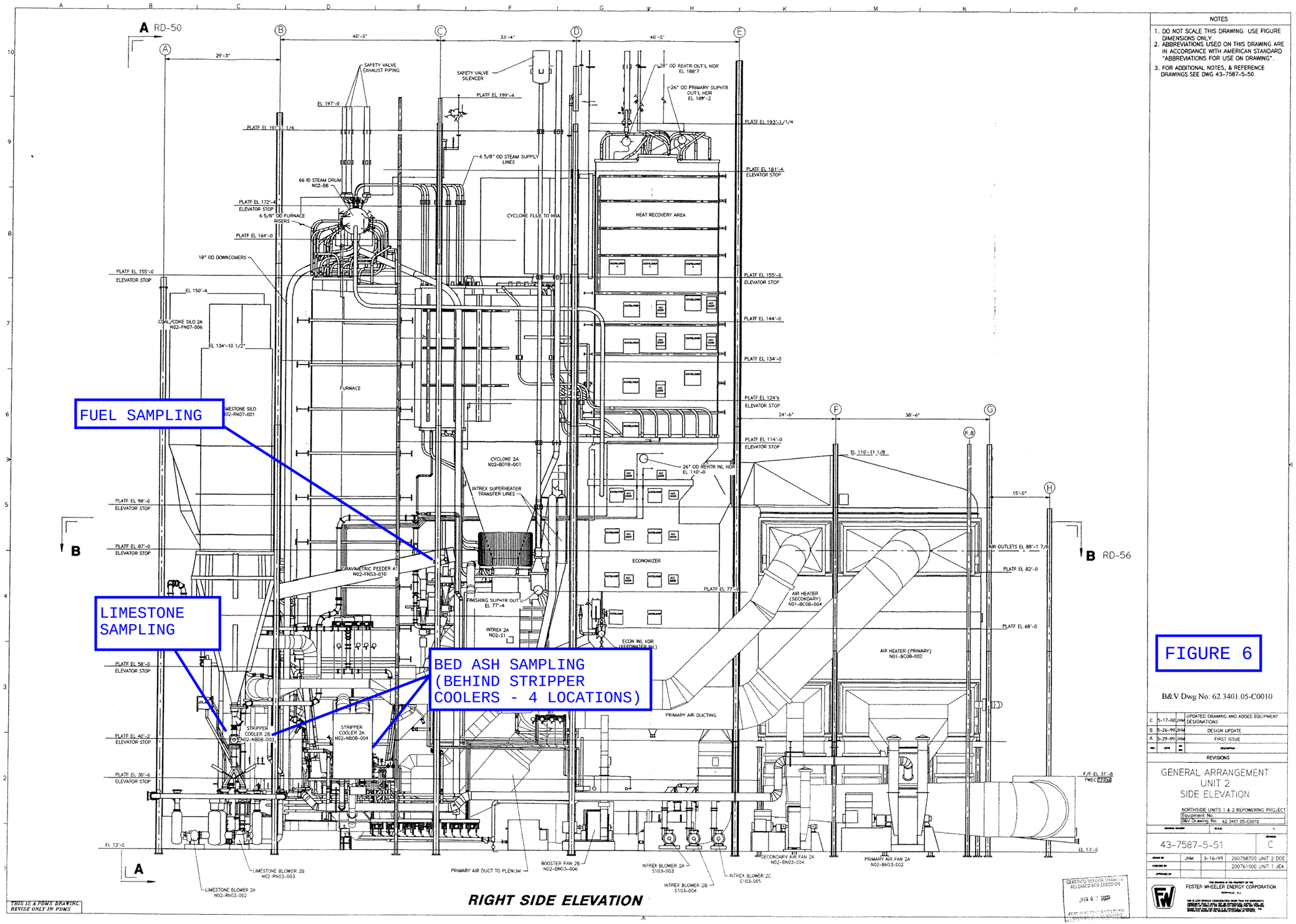

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3. FOR ADDITIONAL NOTES, & REFERENCE DRAWINGS SEE DWG 43-7587-5-50

FIGURE 6

B&V Dwg No: 62.3401.05-C0010

REV.	DATE	BY	DESCRIPTION
C	5-17-00	JHM	UPDATED DRAWING AND ADDED EQUIPMENT DESIGNATIONS
B	5-26-99	JHM	DESIGN UPDATE
A	3-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
SIDE ELEVATION

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No:
B&V Drawing No: 62.3401.05-C0010

43-7587-5-51 C

DRAWN BY JHM 3-16-99 200758700 UNIT 2 DOE
CHECKED BY 200761000 UNIT 1 JEA
APPROVED BY

FOSTER WHEELER ENERGY CORPORATION

CERTIFIED VENDOR DRAWING RELEASED FOR CONSTRUCTION JUN 8 - 2000

P062713.62.3401.05-C0010 St:NE 08/04/00 MM-00739

Fuel Capability Demonstration Test Report 1
for the
JEA Large-Scale CFB Combustion Demonstration Project

100% Pittsburgh 8 Fuel

Submitted to
U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory (NETL)
Pittsburgh, Pennsylvania 15236
Cooperative Agreement No.
DE-FC21-90MC27403

September 3, 2004

DOE Issue, Rev. 1

Prepared by Black & Veatch for:

Building Community

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1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels. Therefore, it was necessary for JEA to demonstrate this capability through a series of tests.

The purpose of the test program was to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility would be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin
    - Furan
- Stack opacity

This test report documents the results of JEA's Fuel Capability Demonstration Tests on 100% Pittsburgh 8 coal for the JEA Large-Scale CFB Combustion Demonstration Project. The tests were conducted in accordance with the Fuel Demonstration Test Protocol in Attachment A.

Throughout this report, unless otherwise indicated, the term "unit" refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF)

1.1 Test Schedule

Unit 2 of the JEA Northside plant site is a Circulating Fluidized Bed Steam Generator designed and constructed by Foster-Wheeler. The steam generator was designed to deliver main steam to a steam turbine at a flow rate of 1,993,591 lb/hr, at a throttle pressure of 2,500 psig, and at a throttle temperature of 1,000 deg F.

The fuel capability demonstration test for the unit firing 100% Pittsburgh 8 coal, was conducted over a four (4) day period beginning on January 13, 2004 and completed on January 16, 2004. During that four (4) day period, data were taken in accordance with the Test Protocol (Attachment A) while the unit was operating at 100% load, 80% load , 60% load, and 40% load.

The following log represents the sequence of testing:

- Day 1 January 13, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 1030 hours; completed at 2100 hours.
  - Boiler performance testing commenced at 1100 hours; completed at 1500 hours.

- Day 2 January 14, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 0751 hours; completed at 1752 hours.
  - Boiler performance testing commenced at 1000 hours; completed at 1400 hours.

- Day 3 January 15, 2004:
  - Unit at 80% load - turbine load set and maintained at approx. 240 MW.
  - Unit began 2-hour stabilization period at 240 MW at 1400 hours.
  - Boiler performance testing commenced at 1600 hours after stabilization period completed; test completed at 2000 hours.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 3 (cont'd) January 15, 2004:
  - Unit load 40% load after completion of testing at 80% load - turbine load set and maintained at approx. 120 MW.
  - Unit began 2-hour stabilization period at 120 MW at 2200 hours.
  - Boiler performance testing commenced at 0000 hours after stabilization period completed; test completed at 0400 hours, Jan. 16, 2004.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 4 January 16, 2004:
  - Unit load increased to 60% load - turbine load set and maintained at approx. 180 MW.
  - Unit began 2-hour stabilization period at 180 MW at 1230 hours.
  - Boiler performance testing commenced at 1430 hours after stabilization period completed; test completed at 1830 hours.
  - Flue gas emissions data taken and recorded by CEMS system.
  - This concluded the testing of JEA Northside Unit 2 firing 100% Pittsburgh 8 coal.

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of “as-fired” fuel
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Fahrenheit
FA	Flyash
FF	Fabric Filter
gpm	gallons per minute

Abbreviation	Definition
gr/acf	grains per actual cubic foot
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater
$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside

Abbreviation	Definition
Pb	Lead
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1

Abbreviation	Definition
W_{fe}	Fuel feed rate (lb/hr)
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number

2.0 SUMMARY OF TEST RESULTS

2.1 Test Requirements

The Protocol required that the following tests be performed and the results be reported at four (4) different unit loads:

- Unit Capacity, percent (all capacities in Megawatts are gross MW).
- Boiler Efficiency, percent (100 % load only).
- Main Steam and Reheat Steam Temperature, deg F.
- Emissions - NOx, SO2, CO, and Particulate (see Section 4.0 of this report).

The results of the test were compared against the design performance data of the boiler produced by Foster-Wheeler. The design performance data for the boiler established by Foster-Wheeler was (Note that the data are for 100% load only - no partial load data were presented):

Boiler efficiency (firing Pittsburgh 8 coal):	88.1 % HHV
Main steam flow at turbine inlet:	1,993,591 lb/hr
Main steam temperature at turbine inlet:	1,000 deg F
Main steam pressure at turbine inlet:	2,500 psig
Hot reheat steam temperature at turbine inlet:	1,000 deg F

The average steam temperatures during the Test shall be within the limits described in the following sections (The average of the readings recorded every minute shall be determined to be the Test average):

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

2.2 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the ‘closed’ position of certain main steam and feedwater system valves. A listing of these valves is included in Attachment F.

2.3 Test Results

The results of the 100% tests are summarized in Table 1. The results of the part-load tests are summarized in Table 3. The performance of the boiler met and/or exceeded all of the design values provided by Foster-Wheeler. No problems with the fuel feeding system were observed or recorded during the full- and part-load test periods.

TABLE 1 - TESTS RESULTS - 100% LOAD

	Design Maximum-Continuous Rating (MCR)	January 13, 2004 Test (**corrected to MCR)	January 14, 2004 Test (**corrected to MCR)
Boiler Efficiency (percent)	88.1	90.6** (Note 1)	90.6** (Note 1)
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,999,572**	2,000,369**
Pressure (psig)	2,500	2,400	2400
Temperature (°F)	1,000	997**	996.6**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,820,447	1,769,377
Pressure (psig)	547.7	570.9	568.7
Temperature (°F)	1,000	1008.1**	1008.25**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,819,973	1,768,905
Pressure (psig)	608.6	570.5	568.24
Enthalpy (Btu/lb)	1,304.5	1297.3	1,297.3
Feedwater to Economizer			
Temperature (°F)	487.5	484.5	484.1
Pittsburgh 8 Coal Constituents (As-Received)			
Carbon %	68.6	72.7	72.3
Hydrogen %	4.6	4.84	4.7
Sulfur %	3.3	4.84	4.56
Nitrogen %	1.3	1.37	1.35
Chlorine %	0.09	0.18	0.14
Oxygen %	4.11	2.11	2.54
Ash %	12.8	6.89	7.06
Moisture %	5.2	7.26	7.39
HHV (Btu/lb)	12,690	12,877	12,970
Limestone Composition (% By Weight)			
CaCO3	92.0	90.86	91.81
MgCO3	3.0	3.31	2.95
Inerts	4.0	5.34	4.9
Total Moisture	1.0	0.49	0.34

	Design Maximum-Continuous Rating (MCR)	January 13, 2004 Test (**corrected to MCR)	January 14, 2004 Test (**corrected to MCR)
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	45.15	46.02
MgO and inerts	15.0	54.85	53.98
AQCS Lime Slurry Density – % Solids	35	5.57	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	57,600	54,625
Flue Gas Emissions			
Nitrogen Oxides, NOx, lb/MMBtu (HHV)	0.09	0.074	0.081
Uncontrolled SO2, lb/MMBtu (HHV)	5.20	7.52	7.03
Boiler Outlet SO2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2371	.2902
Stack SO2 lb/MMBtu, (HHV)	0.15	0.102	0.106
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.004	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.026	0.027
Opacity, percent	10	1.1	1.0
Ammonia (NH3) Slip, ppmvd	2.0	1.17	
Ammonia feed rate, gal/hr	NA	7.16	8.38
Lead, lb/MMBtu	2.60×10^{-5} (max)	3.516×10^{-7}	
Mercury (fuel and limestone)	NA	8.24×10^{-6}	
Mercury, lb/MMBtu (at stack)	1.05×10^{-5} (max)	7.238×10^{-6} (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	14.0	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 3.09 \times 10^{-5}$	
Dioxins / Furans	No Limit	6.52×10^{-14}	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from Foster-Wheeler data).
NOTE 2: Refer to Section 4.3.4.1.
NOTE 3: Design boiler outlet SO2 emission rate based on 85% removal of SO2 in the boiler.

TABLE 2 - BOILER & SDA SO2 REMOVAL EFFICIENCY

	Design Basis	January 13, 2004 Test	January 14, 2004 Test
Percent of total SO2 removed by boiler	85.0 typical, with range of 75 - 90	96.8	95.8
Percent of total SO2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.8	2.7
Percent of Total SO2 Removed	97.1	98.6	98.5
Percent of SO2 entering SDA removed in SDA	81.0 typical with range 90 – 71	56.9	63.5
Boiler Calcium to Sulfur Ratio	< 2.88	1.77	1.86

TABLE 3 - TEST RESULTS - PARTIAL LOADS

	Day 3	Day 4	
Percent Load	80%	40%	60%
Unit Capacity (MW)	240	120	180
Total Main Steam Flow, lb/hr	1,435,543	1,070,747	738,397
Main Steam Temperature, deg F	1,003	998	999
Main Steam Pressure, psig	2,400.6	1,800.4	1,300.4
Cold Reheat Steam Temperature, deg F	576.6	572.7	565.9
Hot Reheat Steam Temperature, deg F	1,005	1,006	1,004
NOx, lb/MMBtu	0.080	0.072	0.082
CO, lb/MMBtu	0.044	0.118	0.053
SO2, lb/MMBtu	0.082	0.081	0.108
Opacity, percent	1.0	1.5	1.4

2.3.1 Unit Capacity - During the four (4) day testing period, the boiler was successfully operated at 100 % MCR (turbine load of approximately 300 MW), for day 1 and day 2, and at partial loads of 40% (turbine load of approximately 120 MW), 60% (turbine load of approximately 180 MW), and 80% (turbine load of approximately 240 MW), for day 3 and day 4. The unit operated steadily at each of the stated loads without any deviation in unit output. Prior to each of the testing periods, the unit was brought to load and allowed to stabilize for two (2) hours prior to the start of each test.

2.3.2 Boiler Efficiency - The steam generator operated at corrected efficiencies of 90.6 % and 90.6 % on Day 1 and Day 2, respectively, of the testing period. These efficiencies exceeded the design values by approximately 2.5 %.

2.3.3 Steam Temperature and Steam Pressure - During both days at 100% load operation, the average corrected main steam temperature measured at the turbine inlet was 997 deg F, which is below the

design tolerances of the unit. The reduced temperature is due to the loss of superheat surface caused by tube failures attributed to a lack of solution annealing on the original tube bends during manufacture of the tubes. The corrected hot reheat steam temperature measured at the turbine inlet was 1008.2 deg F, which is within the design tolerances of the unit. During partial load operation, the main steam temperatures and the hot reheat temperatures were within the design tolerances previously listed in Section 2.1.

The throttle pressure of the unit was maintained at a value of 2400 psig during both days of the 100% load operation. As can be seen in the previous table, this value is less than the design value of 2500 psig. Although the unit is operated at the reduced pressure, the unit is able to achieve full load. JEA has chosen to operate at this reduced pressure because it provides an additional margin of safety for the turbine stop valves and the high pressure feedwater heaters.

2.3.4 Steam Production - The steam flows of the unit at the 100% load operation cases and partial load operation cases were each determined by adding the main steam desuperheating system flow rates to the feed water system flow rates, and subtracting the continuous blow down flow rates and the sootblowing steam flow rates. The data for each of these systems were retrieved from the plant information system database. The main steam flow rates were corrected to the MCR condition. The corrected main steam flow rates determined for the 100% load operation cases were greater than the design flow rates established by Foster-Wheeler. The main steam flow rates at the partial load operation cases were adequate enough to maintain the steam turbine at the required output.

2.3.5 Calcium to Sulfur Ratio (Ca:S) - The calcium to sulfur ratio represents the ability of the CFB boiler and limestone feed system to effectively remove the sulfur dioxide produced by the combustion process of the boiler. The maximum ratio established for firing Pittsburgh 8 coal was 2.88. The calculated calcium to sulfur ratios for Day 1 and Day 2 are approximately 1.77 and 1.86, respectively. These values represent SO2 removal efficiencies for the boiler of greater than 90 % which are acceptable values for a CFB. SO2 reductions of 90% are typically achieved in a CFB with Ca:S ratios of 2 to 2.5. These values are dependent on the sulfur content in the fuel and the reactivity of the limestone.

3.0 BOILER EFFICIENCY TESTS

The unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in Section 2 of the Attachment A Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency. Prior to beginning the Day 1 testing, it was noted that one of the eight (8) coal feeders was offline and operation of the unit was considered to be unstable. The testing was delayed until the coal feeder was returned to service and operation of the unit was stable. No further operational restrictions were observed during the 4 days of testing.

3.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcinations / sulfation. A complete description of

the modified procedures is included in Section 4.2 of Attachment A. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the flyash, and the heat loss due to radiation and convection from the insulated boiler surfaces. A complete list of the heat losses can be found in Section 4.2.1 of Attachment A. The completed efficiency calculations are included in Attachment F to this report.

3.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. The data provided by the plant instrumentation is included in *Attachment D, PI Data Summary*. Additional data required for the boiler efficiency calculations were provided by two independent testing contractors, PGT/ESC, and Clean Air Engineering (CAE). A summary of this information is located in *Attachments G, H, I, J, and K, lab analyses provided by PGT/ESC for the fuel, limestone, bed ash, flyash, and environmental data,* and *Attachment C, CAE Test Report,* respectively. As directed in the test protocol (Attachment A), test data for days 1 and 2 were taken and labeled by CAE and PGT. No flue gas sampling was performed on the unit during operations at reduced loads. Data were, however, recorded by the CEMS system and are reported in this document.

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the plant information system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, flyash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis. (Refer to Figures 1 thru 6 for approximate locations).

<u>Lime (Figure 1):</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Flyash (Figures 2, 3, and 4):</u>

Flyash samples were taken by two different methods.

1) Flyash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Flyash was also taken by grab sample method in two different locations. One grab sample was taken every hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel (Figures 4, 5, and 6):</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

<u>Limestone (Figures 4 and 6):</u>

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

Bed Ash (Figure 6):

Bed Ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

As instructed by the Test Protocol, all of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation. The results of the lab analyses are included in Attachments G, H, I, and J.

4.0 AQCS INLET AND STACK TESTS

4.1 System Description

The Unit 2 AQCS consists of a single, lime-based spray dryer absorber (SDA) and a multi-compartment pulse jet fabric filter (PJFF). The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/flyash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 flyash silo or the Unit 2 AQCS recycle bin. Flyash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [Ca(OH)2] slurry, which is fed to the atomizers as a supplemental reagent.

4.2 Unit Emissions Design Points

The following sections describe the desired emissions design goals of the unit. The tests were conducted in accordance with standard emissions testing practices and test methods as listed in Section 4.2.7. It should be noted that not all tests conducted fit exactly the 4 hour performance test period that was the basis of the fuel capability demonstration test. Several of the tests (especially those not based on CEMS) had durations that were different than the 4 hour performance period due to the requirements of the testing method and good engineering/testing practice. All sampling tests were done at the 100% load case only. All data collected by the CEMS were done at the 100%, 80%, 60% and 40% performance load tests.

4.3 Emission Design Limits and Results

4.3.1 NOx / SO2 / Particulate Emission Design Limits / Results

The following gaseous emissions were measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NOx) values in the flue gas as measured in the stack were expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMBtu values reported by the Continuous Emissions Monitoring system (CEMS) were used as the measure of NOx in the flue gas over the course of each fuel test. The average NOx values for Day 1 and Day 2, based on HHV, were 0.074 lb/MMBtu and 0.081 lb/MMBtu, respectively. Both of these values were less than the expected maximum value.

b. **Sulfur dioxide** (SO2) The design operating condition of the unit is to remove 85 percent of the SO2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. Burning performance coal with a boiler SO2 removal efficiency of 85%, the SO2

concentration at the air heater outlet was expected to be 0.78 lb/MMBtu, with an uncontrolled SO2 emission rate (at 0% SO2 removal) calculated to be 5.20 lb/MMBtu. JEA has chosen to operate at a much higher boiler SO2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO2 emissions. Over time the operations group has learned that if limestone feed is higher than normally desired the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO2 removal and increased SDA removal.

The SO2 concentration at the SDA inlet was measured by an independent test contractor, Clean Air Engineering (CAE). These results are included in Attachment C. The average SO2 values for Day 1 and Day 2, based on HHV of the fuel, out of the air heaters and into the SDA, were 0.2445 lb/MMBtu and 0.2992 lb/MMBtu, respectively. Both of these values were below the expected outlet emission rate. In fact, the boiler removed 97% and 96% respectively, in comparison to the design removal rate of 85%. Uncontrolled SO2 emissions rates were calculated to be 7.52 lb/MMBtu and 7.03 lb/MMBtu, respectively, for an increased SO2 input of 44.6% and 35.2% above the design performance coal SO2 input of 5.20 lb/MMBtu.

The SO2 emissions from the stack during the execution of the tests were expected to be less than 0.15 lb/MMBtu. The hourly average lb/MMBtu values (based on HHV of the fuel) reported by CEMS were used as the measure of SO2 emissions from the stack for the test. The average SO2 values for Day 1 and Day 2, (based on HHV of the fuel) were 0.102 lb/MMBtu and 0.106 lb/MMBtu, respectively. These values were 32% and 29% lower than the 0.15 lb/MMBtu permitted emission rate.

b. **Solid particulate matter** in the flue gas at the fabric filter outlet was expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input. These values were measured at the stack by CAE. The average particulate matter value for the testing period was 0.004 lb/MMBtu which is below the expected maximum value.

4.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas was expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by the plant CEMS. The average values for Day 1 and Day 2 were 0.026 lb/MMBtu and 0.027 lb/MMBtu, respectively. The average values were less than the maximum expected value.

4.3.3 SO3 Emissions Design Point

Sulfur Trioxide (SO3) in the flue gas was assumed to be zero due to the high removal efficiency of the SDA. No testing was done for SO3 as explained in the Test Protocol located in Attachment A. See Section 4.2.3 of the Fuel Capability Test Protocol for the rationale.

4.3.4 NH3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH3, Lead, Mercury, and Fluorine gaseous emissions were measured during the Test (EPA Permit averaging period). Mercury sampling and analysis was performed at the inlet to the AQCS system in addition to the samples taken at the stack. Both samples were taken by CAE. Lead, ammonia and fluorine were sampled only at the stack by CAE. The average values are indicated in Table1.

4.3.4.1 Mercury Testing Anomaly

During the emissions tests, the reagent used in the fourth impinger of the Ontario Hydro sampling train was a 5% HNO3 (nitric acid) / 10% H2O2 (hydrogen peroxide) solution. Mercury levels in both the 5% / 10% reagent blank and the 5% / 10% portion of the field train blanks were elevated. The mercury concentration in the reagent field blanks of the other solutions (KCI, potassium chloride, and KMnO4, potassium permanganate) used in the Ontario Hydro sampling train was at the expected levels or below the detection limit. In accordance with the Ontario Hydro Method, the allowable blank adjustments have been made to the final results presented.

A review of the total mercury in the coal was completed for comparison to measured values. The coal analyses indicated a mercury content of approximately 0.105 µg/g, with a limestone mercury content of 0.09 µg/g. This is equivalent to a total mercury content of 0.22 lb/hr. This represents more mercury than what was measured by the independent test contractor at the inlet to the SDA. However due to the bias adjustment made by the independent test contractor, the removal efficiency was lower than expected. Subsequent tests should help determine the expected mercury removal efficiency of the unit.

4.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions were measured at the stack by CAE for the 4-hour interval during the Test (EPA Permit averaging period). Note this test is only being done for the 100% Pittsburgh 8 coal. The resulting average values are indicated in Table 1.

4.3.6 Opacity

The opacity was measured by the plant CEMS/COMS (Continuous Opacity Monitoring System) to determine the opacity of the unit over a six minute block average during the test period. The maximum expected opacity was 10%. The testing indicated that the maximum opacity of the unit during the two day test was 1.1 %, which is much less than the maximum opacity value.

4.3.7 Ammonia, NH3 Slip

Ammonia slip was guaranteed to be less than 2.0 ppmvd at 3 percent O_2 at Design Maximum Load. The resultant averages were around 1.17 ppmvd when measured using the CTM - 027 EPA method. This identifies that the SNCR was working within design parameters and meeting the boiler NOx removal efficiency as required. An ammonia slip level of less than 2.0 ppmvd is recognized as an industry standard acceptable value.

4.4 Flue Gas Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – CTM 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans – PCDD/F

Specific descriptions of the testing methods (non-CEMS) are included in the Clean Air Engineering Emissions Test Report located in Attachment D of this document.

4.5 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration and as listed in Section 4.2.7. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NOX, SO2, and CO2 analyzers. The data listed for CEMS in Section 4.2.7 originated from the certified Data Acquisition Handling System (DAHS).

Attachments

Attachment A - Fuel Capability Demonstration Test Protocol

Attachment B - Boiler Efficiency Calculation

Attachment C - CAE Test Report

Attachment D - PI Data Summary

Attachment E - Abbreviation List

Attachment F - Isolation Valve List

Attachment G - Fuel Analyses - Pittsburgh 8 Coal

Attachment H - Limestone Analyses

Attachment I - Bed Ash Analyses

Attachment J - Flyash (Air Heater and PJFF) Analyses

Attachment K - Ambient Data, Jan. 13, 2004 and Jan. 14, 2004

Attachment L - Ambient Temperatures, Jan. 15, 2004 and Jan. 16, 2004

Attachment M - Ontario Hydro Mercury Emission Summary

ATTACHMENT A

Fuel Capability Demonstration Test Protocol

This Document is located via the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

ATTACHMENT B

Boiler Efficiency Calculation

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	207,558	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7270	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0484	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0211	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0137	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0484	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0689	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0726	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	12,877	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	57,600	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9086	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0331	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0534	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0049	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.85496		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	398	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0008	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0008	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2102	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	34,171	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0276	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0276	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2252	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	36,608	lb/hr	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	109	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	45	lb/hr	
1.5.4	Fan Outlet Temperature, °F	109	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	755,011	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	101	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	35,970	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	164	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	44702	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	178	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	61.02	°F	ta
1.6.2	Ambient wet bulb temperature, °F	49.56	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.43	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0045	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	306.50	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	577.18	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0041	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, psig	2177.3	psig	pfw - Plant instrument.
1.8.2	Temperature, °F	484.5	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,882,591	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, psig (drum pressure)	2,564.6	psig	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.9	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, lb/hr	0.00	lb/hr	SB - Plant instrument
1.10.2	Pressure, psig	0.00	psig	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, psig	2,707.7	psig	pdsw - Plant instrument.
1.11.2	Temperature, °F	305.0	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	11,224	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, psig (superheater outlet)	2,400.4	psig	pms - Plant instrument.
1.12.2	Temperature, °F	1,003.3	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,893,814	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, psig	727.35	psig	pdswrh - Plant instrument.
1.13.2	Temperature, °F	186.59	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	474	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, psig	570.48	psig	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	607.52	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, psig	570.91	psig	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,000.03	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, lb/hr	1,819,973	lb/hr	RHin - From turbine heat.

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CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1	Average Air Heater Inlet Temperature	107.50	

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	195,933	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0320	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9680		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1	**Accumulation of Bed Inventory**	0	lb/h
4.2	**Corrected Ash Carbon Content**		
4.2.1	Bottom Ash, fraction	0.0008	lb/lb BA
4.2.2	Fly Ash, fraction	0.0276	lb/lb FA
4.3	**Bottom Ash Flow Rate**		
4.3.1	Total bottom ash including bed change	34,171.3939550	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.7670	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.976495449	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	57600	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.766996783	mole Ca/mole S	
	LImestone Flow Rate from PI Data, lb/h	**57,600**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-1.03078E-05	percent	
4.4.6	Calculated Fly Ash Flow Rate	36,608	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000015)	percent	
4.5	**Total Dry Refuse**			
4.5.1	Total Dry Refuse Hourly Flow Rate	70,780	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.3612	lb/lb AF fuel	
4.6	**Heating Value Of Total Dry Refuse**			
4.6.1	Average Carbon Content Of Ash	0.0147	fraction	
4.6.2	Heating Value Of Dry Refuse	212.59	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1	**Carbon Burned Adjusted For Limestone**		
5.1.1	Carbon Burned	0.7217	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7503	lb/lb AF fuel

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Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	27.770	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3455	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.7905	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.7490	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6279	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	9.9539	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0137	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0726	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.4323	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.0586	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.3476	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6076	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	13.9126	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7629	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.3234	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0111	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	81.0533	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1121	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-0.000534978	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1432		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8118		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.2999	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6023	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.3625	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01032	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.1981	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.6158	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1046	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7086	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	13.8648	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7553	lb/lb mole	

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5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0471	fraction
5.2.19.2	Nitrogen, fraction weight	0.7470	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2059	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.304	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.7490	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4763	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.4502	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0137	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0726	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.4323	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.0556	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.6923	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.6975	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.2542	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8078	lb/lb AF fuel

		Volume Basis	
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	% Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.1073	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.1627	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1183	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-0.000863113	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1511	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8089	
5.3.12	Weight Dry FG At Air Heater INLET	12.7033	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8408	lb/lb mole

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		Volume Basis	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	14.0474	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01085	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3475	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.4688	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1100	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	7.0154	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.2653	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9380	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0374	fraction
5.3.17.2	Nitrogen, fraction weight	0.7386	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2156	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0085	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0358	fraction
5.3.18.2	Nitrogen, fraction weight	0.7073	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2065	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0081	fraction
5.3.18.6	Moisture, fraction weight	0.0422	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.157	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.7490	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5198	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.5945	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0137	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0726	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.4323	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.0565	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	12.8801	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.6708	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	13.4429	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.7945	lb/lb mole

		Volume Basis	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	% Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	13.8441	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.5125	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1084	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.9243	percent volume
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		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	14.8740	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8679	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.1302	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1165	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-0.000868122	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	9.78568E-05	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

	Oxygen
C0	-1.1891960E+02
C1	4.2295190E-01
C2	-1.6897910E-04
C3	3.7071740E-07
C4	-2.7439490E-10
C5	7.384742E-14

5.5.2 a	Flue Gas Constituent Enthalpy At tG15	5.111496E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8	6.702388E+00

	Nitrogen
C0	-1.3472300E+02
C1	4.6872240E-01
C2	-8.8993190E-05
C3	1.1982390E-07
C4	-3.7714980E-11
C5	-3.5026400E-16

5.5.2 b	Flue Gas Constituent Enthalpy At tG15	5.6669989E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8	7.5168742E+00

	Carbon Dioxide
C0	-8.5316190E+01
C1	1.9512780E-01
C2	3.5498060E-04
C3	-1.7900110E-07
C4	4.0682850E-11
C5	1.0285430E-17

5.5.2 c	Flue Gas Constituent Enthalpy At tG15	4.9592543E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8	6.2194310E+00

	Carbon Monoxide
C0	-1.3574040E+02
C1	4.7377220E-01
C2	-1.0337790E-04
C3	1.5716920E-07
C4	-6.4869650E-11
C5	6.1175980E-15

5.5.2 d	Flue Gas Constituent Enthalpy At tG15	5.7274953E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8	7.5832565E+00

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	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.6109522E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	4.5733958E+00		

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	54.95	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	7.21	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	634.93	Btu/lb AF fuel	
5.6 HHV Percent Loss, as tested		4.93	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1198.60	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * $(tG15)^2$ + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	75.50	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	81.49	Btu/lb AF fuel	
6.4 HHV Percent Loss, as tested		0.63	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	485.57	Btu/lb AF fuel
7.2 HHV Percent Loss, as tested		3.77	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	76.80	Btu/lb AF fuel
8.2 HHV Percent Loss, as tested		0.60	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	12.67	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	7.44	Btu/lb AF fuel
9.2 Total Dry Refuse Heat Loss, as tested		20.11	Btu/lb AF fuel
9.3 HHV Percent Loss, as tested		0.16	percent

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10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.26	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	151.99	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	52.74	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	5.96	Btu/lb
10.3 HHV Percent Loss, as tested		0.05	percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	180.35	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	1.60	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-315.59	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-133.64	Btu/lb AF Fuel
11.5 HHV Percent Loss		-1.04	percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss		0.27	percent
12.1.1	Radiation & Convection Heat Loss	34.52	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	634.93
13.1.2	81.49
13.1.3	485.57
13.1.4	76.80
13.1.5	20.11
13.1.6	5.96
13.1.7	-133.64
13.1.8	34.52
	1,205.74

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.93
13.1.10	Moisture In Fuel	0.63
13.1.11	H2O From H2 In Fuel	3.77
13.1.12	Unburned Combustibles In Refuse	0.60
13.1.13	Dry Refuse	0.16
13.1.14	Moisture In Combustion Air	0.05
13.1.15	Calcination/Sulfation	-1.04
13.1.16	Radiation & Convection	0.27
		9.36
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***90.64***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.73	Btu/lb
14.1.2	Blow Down, Btu/lb	738.78	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	279.65	Btu/lb
14.1.5	Main Steam, Btu/lb	1463.30	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	156.22	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1295.99	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1517.12	Btu/lb
14.2 Heat Output		2,286,862,656	Btu/h
		2,288,632,676	

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,523,107,338	Btu/h
15.1.2	Fuel Burned - CALCULATED	195,933	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-9.18857E-06	percent

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	206,906	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7235	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0472	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0254	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0135	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0456	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0706	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0739	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	12,970	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	54,625	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9181	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0295	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0490	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0034	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.88668		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	463	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0004	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0004	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2099	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	30,240	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0276	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0276	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2252	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	36,608	lb/hr	Wfam - Weight of fly ash from isokenetic sample colleciton.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,682,824	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	108	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	38	lb/hr	
1.5.4	Fan Outlet Temperature, °F	108	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	721,210	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	102	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	36,289	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	165	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	45477	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	179	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2
Test Date:	JANUARY 14, 2004
Test Start Time:	10:15 AM
Test End Time:	2:15 PM
Test Duration, hours:	4

Boiler Efficiency: 90.64

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	62.78	°F	ta
1.6.2	Ambient wet bulb temperature, °F	51.26	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.24	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0051	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	305.82	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	578.26	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0041	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	2.90	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Meausred	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, psig	2030.0	psig	pfw - Plant instrument.
1.8.2	Temperature, °F	484.1	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,810,754	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, psig (drum pressure)	2,560.0	psig	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.6	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, lb/hr	0.00	lb/hr	SB - Plant instrument
1.10.2	Pressure, psig	0.00	psig	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, psig	2,697.7	psig	pdsw - Plant instrument.
1.11.2	Temperature, °F	308.1	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	30,013	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, psig (superheater outlet)	2,400.5	psig	pms - Plant instrument.
1.12.2	Temperature, °F	1,003.4	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,840,767	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, psig	725.58	psig	pdswrh - Plant instrument.
1.13.2	Temperature, °F	188.62	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	472	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, psig	568.24	psig	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	607.19	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, psig	568.76	psig	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,001.91	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, lb/hr	1,768,905	lb/hr	RHin - From turbine heat.

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1	Average Air Heater Inlet Temperature	107.36	

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	189,635	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0322	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9678		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1	**Accumulation of Bed Inventory**	0	lb/h
4.2	**Corrected Ash Carbon Content**		
4.2.1	Bottom Ash, fraction	0.0004	lb/lb BA
4.2.2	Fly Ash, fraction	0.0276	lb/lb FA
4.3	**Bottom Ash Flow Rate**		
4.3.1	Total bottom ash including bed change	30,239.9610800	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.858457038	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.959955857	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	54625	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.858452254	mole Ca/mole S	
	Limestone Flow Rate from PI Data	**54,625**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-0.000257424	percent	
4.4.6	Calculated Fly Ash Flow Rate	36,608	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000017)	percent	
4.5	**Total Dry Refuse**			
4.5.1	Total Dry Refuse Hourly Flow Rate	66,848	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.3525	lb/lb AF fuel	
4.6	**Heating Value Of Total Dry Refuse**			
4.6.1	Average Carbon Content Of Ash	0.0153	fraction	
4.6.2	Heating Value Of Dry Refuse	221.79	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1	**Carbon Burned Adjusted For Limestone**		
5.1.1	Carbon Burned	0.7181	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7473	lb/lb AF fuel

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	27.75	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3184	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.7006	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.7382	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0029	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6213	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	9.8374	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0135	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0739	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.4214	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0010	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.0647	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.2134	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6226	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	13.7743	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7741	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.4191	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0106	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.9584	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1119	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-2.97191E-06	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1442		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8108		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.1631	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6194	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.4486	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.00989	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.1971	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.5094	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1043	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7307	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	13.7241	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7682	lb/lb mole	

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0470	fraction
5.2.19.2	Nitrogen, fraction weight	0.7457	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2073	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components - NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.28	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.7382	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0029	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4713	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.3390	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0135	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0739	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.4214	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0010	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.0614	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.5649	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7133	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.1226	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8201	lb/lb AF fuel

		Volume Basis % Dry Flue Gas	
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas		
5.3.7.1	Carbon Dioxide, volume percent	15.2082	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0112	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.0627	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1180	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-1.6827E-05	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1521	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8078	
5.3.12	Weight Dry FG At Air Heater INLET	12.5771	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8578	lb/lb mole

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

		Volume Basis % Wet Flue Gas	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.3.14.1	Carbon Dioxide, volume percent	14.1384	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01040	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3468	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.3603	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1097	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	7.0345	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.1348	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9514	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7372	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2169	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0085	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0357	fraction
5.3.18.2	Nitrogen, fraction weight	0.7059	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2077	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0082	fraction
5.3.18.6	Moisture, fraction weight	0.0423	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	18.12	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.7382	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0029	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.3982	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.0962	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0135	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0739	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.4214	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0010	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.0598	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	12.2489	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7612	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	12.8050	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.8443	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas		
5.4.7.1 a	Carbon Dioxide, volume percent	14.5007	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	2.9000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.2819	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1125	percent volume
5.4.7.6 a	Moisture in flue gas, voluem percent	7.1942	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.6248	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.1248	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.1177	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1212	percent volume
5.4.7.6 b	Moisture in flue gas, voluem percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet	2.9	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	8.00226E-06	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-0.00034795	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

		Oxygen
	C0	-1.1891960E+02
	C1	4.2295190E-01
	C2	-1.6897910E-04
	C3	3.7071740E-07
	C4	-2.7439490E-10
	C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15	5.096182E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8	6.670957E+00

		Nitrogen
	C0	-1.3472300E+02
	C1	4.6872240E-01
	C2	-8.8993190E-05
	C3	1.1982390E-07
	C4	-3.7714980E-11
	C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15	5.6502462E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8	7.4816825E+00

		Carbon Dioxide
	C0	-8.5316190E+01
	C1	1.9512780E-01
	C2	3.5498060E-04
	C3	-1.7900110E-07
	C4	4.0682850E-11
	C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15	4.9437727E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8	6.1900302E+00

		Carbon Monoxide
	C0	-1.3574040E+02
	C1	4.7377220E-01
	C2	-1.0337790E-04
	C3	1.5716920E-07
	C4	-6.4869650E-11
	C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15	5.7105255E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8	7.5477452E+00

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.5997781E+01	
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	4.5518156E+00	

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	54.78	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	7.18	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	626.59	Btu/lb AF fuel	
5.6 HHV Percent Loss, as tested		4.83	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1198.29	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * $(tG15)^2$ + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	75.36	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	82.96	Btu/lb AF fuel	
6.4 HHV Percent Loss, as tested		0.64	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	473.25	Btu/lb AF fuel
7.2 HHV Percent Loss, as tested		3.65	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	78.18	Btu/lb AF fuel
8.2 HHV Percent Loss, as tested		0.60	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	14.17	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	7.66	Btu/lb AF fuel
9.2 Total Dry Refuse Heat Loss, as tested		21.83	Btu/lb AF fuel
9.3 HHV Percent Loss, as tested		0.17	percent

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.10	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	151.65	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	52.67	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	6.55	Btu/lb
10.3 HHV Percent Loss, as tested		0.05	percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	184.53	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	1.09	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-297.01	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-111.39	Btu/lb AF Fuel
11.5 HHV Percent Loss		-0.86	percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss		0.27	percent
12.1.1	Radiation & Convection Heat Loss	35.62	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	626.59
13.1.2	82.96
13.1.3	473.25
13.1.4	78.18
13.1.5	21.83
13.1.6	6.55
13.1.7	-111.39
13.1.8	35.62
	1,213.60

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.83
13.1.10	Moisture In Fuel	0.64
13.1.11	H2O From H2 In Fuel	3.65
13.1.12	Unburned Combustibles In Refuse	0.60
13.1.13	Dry Refuse	0.17
13.1.14	Moisture In Combustion Air	0.05
13.1.15	Calcination/Sulfation	-0.86
13.1.16	Radiation & Convection	0.27
		9.36
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***90.64***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.20	Btu/lb
14.1.2	Blow Down, Btu/lb	738.25	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	282.79	Btu/lb
14.1.5	Main Steam, Btu/lb	1463.41	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	158.25	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1295.99	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1518.20	Btu/lb
14.2 Heat Output		2,229,406,364	Btu/h
		2,231,155,818	

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,459,546,374	Btu/h
15.1.2	Fuel Burned - CALCULATED	189,633	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	0.000711725	percent

ATTACHMENT C

CAE Test Report

Tony Compaan
Black & Veatch Corporation
10751 Deerwood Park Boulevard, Suite 130
Jacksonville, FL 32256

REPORT ON
LARGE SCALE CFB COMBUSTION DEMONSTRATION PROJECT
100% PITTSBURGH NO. 8 COAL

Performed for:
BLACK & VEATCH CORPORATION
UNIT 2, SDA INLET AND STACK
JEA - NORTHSIDE GENERATING STATION

Client Reference No: 137064.96.1400
CleanAir Project No: 9475-1
Revision 0: DRAFT (February 23, 2004)

To the best of our knowledge, the data presented in this report are accurate and complete and error free, legible and representative of the actual emissions during the test program.

Submitted by,

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Project Manager
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Reviewed by,

Timothy D. Rodak
Manager, Pittsburgh Regional Office

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PROJECT OVERVIEW

The Northside Generating Station Repowering project provided JEA (formerly the Jacksonville Electric Authority) with the two largest circulating fluidized bed (CFB) boilers in the world. The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Black and Veatch Corporation (B&V) contracted Clean Air Engineering, Inc. (CleanAir) to perform the air emission measurements required as part of the demonstration test program. This report covers air emission measurements obtained during the firing of 100% Pittsburgh No. 8 coal to the unit.

The test program included the measurement of the following parameters:

- particulate matter (PM), [SDA Inlet and Stack];
- sulfur dioxide (SO_2), [SDA Inlet];
- fluoride (F), [Stack];
- dibenzo-p-dioxins and dibenzofurans (PCDD/F), [Stack];
- lead (Pb), [Stack];
- speciation of mercury (Hg^0, Hg^{2+}, Hg^{tp}), [SDA Inlet and Stack];
- ammonia (NH_3).

The field portion of the test program took place at the Unit 2 SDA Inlet and Stack locations on January 13 and 14, 2004. Coordinating the field portion of the testing were:

T. Compaan – Black And Veatch
R. Huggins – Black And Veatch
W. Goodrich - JEA
K. Davis - JEA
J. Martin - RMB
J. Stroud - Clean Air Engineering

Table 1-1 contains a summary of the specific test locations, various reference methods and sampling periods for each of the sources sampled during the program.

The results of the test program are summarized in Table 1-2. A more detailed presentation of the test data is contained in Tables 2-1 through 2-11. Process data collected during the test program is contained in Appendix H.

PROJECT OVERVIEW

Table 1-1:
Summary of Air Emission Field Test Program

Run Number	Location	Method	Analyte	Date	Start Time	End Time	Notes
1	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/13/04	11:26	12:36	
2	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/13/04	13:26	15:01	
3	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/13/04	16:50	18:38	
1	Unit 2 SDA Inlet	Method 6C	SO2	1/13/04	11:26	12:26	
2	Unit 2 SDA Inlet	Method 6C	SO2	1/13/04	13:28	14:28	
3	Unit 2 SDA Inlet	Method 6C	SO2	1/13/04	16:52	17:52	
1	Unit 2 SDA Inlet	Ontario Hydro	Mercury	1/13/04	11:19	14:44	
2	Unit 2 SDA Inlet	Ontario Hydro	Mercury	1/13/04	15:50	18:08	
3	Unit 2 SDA Inlet	Ontario Hydro	Mercury	1/13/04	18:40	20:47	
1	Unit 2 Stack	Ontario Hydro	Mercury	1/13/04	11:19	14:42	
2	Unit 2 Stack	Ontario Hydro	Mercury	1/13/04	15:50	18:00	
3	Unit 2 Stack	Ontario Hydro	Mercury	1/13/04	18:40	20:45	
1	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/13/04	10:42	12:51	
2	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/13/04	13:26	15:34	
3	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/13/04	16:50	19:04	
4	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/14/04	10:10	11:15	
5	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/14/04	11:58	13:40	
6	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/14/04	14:31	15:50	
4	Unit 2 SDA Inlet	Method 6C	SO2	1/14/04	10:11	11:11	
5	Unit 2 SDA Inlet	Method 6C	SO2	1/14/04	12:00	13:00	
6	Unit 2 SDA Inlet	Method 6C	SO2	1/14/04	14:32	15:32	
1	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/14/04	13:06	14:15	
2	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/14/04	14:24	15:33	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/14/04	16:11	17:22	
1	Unit 2 Stack	USEPA Method 23	PCDD/F	1/14/04	07:51	11:02	
2	Unit 2 Stack	USEPA Method 23	PCDD/F	1/14/04	11:14	14:28	
3	Unit 2 Stack	USEPA Method 23	PCDD/F	1/14/04	14:42	17:52	
1	Unit 2 Stack	CTM-027	Ammonia	1/14/04	08:02	09:14	
2	Unit 2 Stack	CTM-027	Ammonia	1/14/04	09:42	11:28	
3	Unit 2 Stack	CTM-027	Ammonia	1/14/04	11:41	12:47	

Notes:

Sulfur dioxide concentrations (ppmdv) were converted into the mass emission rate (lb/hr) using the volumetric flow rate from concurrently conducted EPA Method 17 test runs.

022304 115802

PROJECT OVERVIEW

Table 1-2:
Summary of Test Results

Source Constituent	Sampling Method	Average Emission
Unit 2 SDA Inlet		
Sulfur Dioxide (ppmdv), Runs 1-3	EPA M6C	115.8
Sulfur Dioxide (lb/MMBtu), Runs 1-3	EPA M6C/19	0.2405
Sulfur Dioxide (ppmdv), Runs 4-6	EPA M6C	140.7
Sulfur Dioxide (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2929
Particulate (gr/dscf), Runs 1-3	EPA M17	8.08
Particulate (lb/MMBtu), Runs 1-3	EPA M17/19	14.472
Particulate (gr/dscf), Runs 4-6	EPA M17	7.34
Particulate (lb/MMBtu), Runs 4-6	EPA M17/19	13.374
Mercury (lb/hr)	Ontario Hydro	4.902E-02
Mercury (lb/MMBtu)	Ontario Hydro/19	1.777E-05
Unit 2 Stack		
Particulate (gr/dscf)	EPA M5	0.0021
Particulate (lb/hr)	EPA M5	10.80
Particulate (lb/MMBtu)	EPA M5/19	0.0040
Particulate (% Removal)	EPA M5/19	99.97
Fluoride (lb/hr)	EPA M13B/19	<0.0881
Fluoride (lb/MMBtu)	EPA M13B/19	<3.0962E-05
PCDD/PCDF (lb/hr), TEQ	EPA M23	1.803E-10
PCDD/PCDF (lb/MMBtu), TEQ	EPA M23B/19	6.520E-14
Lead (lb/hr)	EPA M29	9.567E-04
Lead (lb/MMBtu)	EPA M29/19	3.516E-07
Mercury (lb/hr)	Ontario Hydro	2.011E-02
Mercury (lb/MMBtu)	Ontario Hydro/19	7.238-06
Mercury (% Removal)	Ontario Hydro/19	58.2
Ammonia (ppmdv)	CTM-027	1.17
Ammonia (lb/hr)	CTM-027	2.047
Ammonia (lb/MMBtu)	CTM-027/19	0.0007

Notes:
1. The mass emission rate (lb/MMBtu) presented in the above table for all test parameters was calculated using a dry fuel factor (F_d) of 9,780 dscf/MMBtu.
2. The mercury results shown are for total mercury emissions. A speciated breakdown of the mercury emissions is contained in Section 2 of the report.
3. Percent removal efficiency was calculated based on the units of lb/MMBtu.
4. USEPA/International toxicity equivalency factors (TEF) were used to calculate the toxicity equivalent (TEQ) of thePCDD/PCDF isomers of concern. Results are expressed as 2,3,7,8-TCDD (tetrachlorodibenzo-p-dioxin).

PROJECT OVERVIEW

PROJECT MANAGER'S COMMENTS

Mass Emission Rate (lb/MMBtu)

The mass emission rate of lb/MMBtu has been calculated using both the dry fuel factor (F_d) of 9,780 dscf/MMBtu and the carbon based fuel factor (F_c) of 1,856 scf/MMBtu.

Ontario Hydro Test Results

The reagent used in the fourth impinger of the Ontario Hydro sampling train is a 5% HNO_3 (nitric acid)/10% H_2O_2 (hydrogen peroxide) solution. Mercury levels in both the 5%/10% Reagent Blank and the 5%/10% portion of the Field Train Blanks were elevated. The Mercury concentration in the Reagent and Field Blanks of the other solutions (KCl, potassium chloride and KMnO4, potassium permanganate) used in the Ontario Hydro sampling train is at expected levels or below the detection limit.

In accordance with the Ontario Hydro Method the allowable blank adjustments (10% of the measured regent blank value or ten (10) times the detection limit whichever is less) have been made to the final results presented.

The elevated elemental mercury present in the 5%/10% sample fraction can be attributed to the corresponding elevated mercury levels present in both the 5%/10% Reagent Blank and the 5%/10% portion of the Field Train Blanks and not to actual mercury emissions. It is recommended that the blank subtraction to the 5%/10% fraction of the sampling trains be based on the mercury level present in the respective location field blanks. All of the remaining fractions would be blank corrected in accordance with the Ontario hydro procedures outlined above. The average emission rate based on the modified blank correction would be SDA Inlet 3.918E-02 lb/hr (1.420 E-05 lb/MMBtu) and Stack 6.328E-03 lb/hr (2.278E-06 lb/MMBtu) with a removal efficiency of 83.0%.

RESULTS

Table 2-1:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 1 through 3

Run No.	**1**	**2**	**3**	**Average**
Date (2004)	January 13	January 13	January 13	
Start Time	11:26	13:28	16:52	
End Time	12:26	14:28	17:52	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
F_c - Unit 2 (dscf/MMBtu)	1,856	1,856	1,856	**1,856**
F_d - Unit 2 (dscf/MMBtu)	9,780	9,780	9,780	**9,780**
Capacity - Unit 2 (Hours per Year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Actual Gas Flow Rate - SDA Inlet (acfm)	985,668	964,818	964,834	**971,773**
Standard Gas Flow Rate - SDA Inlet (scfm)	638,778	628,239	624,168	**630,395**
Dry Standard Gas Flow Rate - SDA Inlet (dscfm)	590,543	579,370	573,670	**581,194**
H_2O - SDA Inlet (%)	7.6	7.8	8.1	**7.8**
Oxygen (O_2) - SDA Inlet (%dv)	4.5	4.5	4.5	**4.5**
Carbon Dioxide (CO_2) - SDA Inlet (%dv)	14.6	14.7	14.6	**14.6**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	130.5	87.7	129.3	**115.8**
Mass Rate (lb/hr)	769	507	740	**672**
Mass Rate (Ton/yr)	3,368	2,220	3,242	**2,943**
Mass Rate (lb/MMBtu) - F_c	0.2762	0.1840	0.2733	**0.2445**
Mass Rate (lb/MMBtu) - F_d	0.2711	0.1819	0.2684	**0.2405**

RESULTS

Table 2-2:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 4 through 6

Run No.	**4**	**5**	**6**	**Average**
Date (2004)	January 14	January 14	January 14	
Start Time	10:11	12:00	14:32	
End Time	11:11	13:00	15:32	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
F_c - Unit 2 (dscf/MMBtu)	1,856	1,856	1,856	**1,856**
F_d - Unit 2 (dscf/MMBtu)	9,780	9,780	9,780	**9,780**
Capacity - Unit 2 (Hours per Year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Actual Gas Flow Rate - SDA Inlet (acfm)	964,351	952,995	973,682	**963,676**
Standard Gas Flow Rate - SDA Inlet (scfm)	629,277	619,489	630,999	**626,588**
Dry Standard Gas Flow Rate - SDA Inlet (dscfm)	585,264	572,328	586,497	**581,363**
H_2O - SDA Inlet (%)	7.0	7.6	7.1	**7.2**
Oxygen (O_2) - SDA Inlet (%dv)	4.6	4.6	4.5	**4.6**
Carbon Dioxide (CO_2) - SDA Inlet (%dv)	14.6	14.6	14.2	**14.5**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	152.6	159.5	110.1	**140.7**
Mass Rate (lb/hr)	891	911	644	**815**
Mass Rate (Ton/yr)	3,902	3,988	2,821	**3,570**
Mass Rate (lb/MMBtu) - F_c	0.3222	0.3369	0.2384	**0.2992**
Mass Rate (lb/MMBtu) - F_d	0.3190	0.3323	0.2275	**0.2929**

RESULTS

Table 2-3:
Unit 2 – SDA Inlet – Particulate Matter, Runs 1 through 3

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:26	13:26	16:50	
Stop Time (approx.)		12:36	15:01	18:38	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.5	4.7	4.6	**4.6**
CO_2	Carbon dioxide (dry volume %)	14.6	14.6	14.6	**14.6**
T_s	Sample temperature (°F)	315	311	316	**314**
B_w	Actual water vapor in gas (% by volume)	7.55	7.78	8.09	**7.81**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	985,668	964,818	964,834	**971,773**
Q_s	Volumetric flow rate, standard (scfm)	638,778	628,239	624,168	**630,395**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	590,543	579,370	573,670	**581,194**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	10.3713	5.9869	7.8949	**8.0844**
$E_{lb/hr}$	Particulate Rate (lb/hr)	52,515	29,741	38,833	**40,363**
$E_{kg/hr}$	Particulate Rate (kg/hr)	23,816	13,488	17,611	**18,305**
$E_{T/yr}$	Particulate Rate (Ton/yr)	230,014	130,266	170,090	**176,790**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	18.4722	10.7949	14.1478	**14.4716**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	18.8409	10.8761	14.3422	**14.6864**

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RESULTS

Table 2-4:
Unit 2 – SDA Inlet – Particulate Matter, Runs 4 through 6

Run No.		4	5	6	Average
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		10:10	11:58	14:31	
Stop Time (approx.)		11:15	13:40	15:50	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	4.8	4.8	**4.9**
CO_2	Carbon dioxide (dry volume %)	14.3	14.2	14.2	**14.2**
T_s	Sample temperature (°F)	311	314	316	**313**
B_w	Actual water vapor in gas (% by volume)	6.99	7.61	7.05	**7.22**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	964,351	952,995	973,682	**963,676**
Q_s	Volumetric flow rate, standard (scfm)	629,277	619,489	630,999	**626,588**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	585,264	572,328	586,497	**581,363**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	7.7634	6.6914	7.5628	**7.3392**
$E_{lb/hr}$	Particulate Rate (lb/hr)	38,958	32,836	38,031	**36,608**
$E_{kg/hr}$	Particulate Rate (kg/hr)	17,668	14,892	17,248	**16,602**
$E_{T/yr}$	Particulate Rate (Ton/yr)	170,635	143,823	166,577	**160,345**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	14.2620	12.1399	13.7209	**13.3743**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	14.3990	12.4982	14.1258	**13.6743**

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RESULTS

Table 2-5:
Unit 2 – SDA Inlet – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.8	4.6	4.8	**4.7**
CO_2	Carbon dioxide (dry volume %)	14.1	14.3	14.1	**14.2**
T_s	Sample temperature (°F)	318	319	318	**318**
B_w	Actual water vapor in gas (% by volume)	8.37	7.91	7.47	**7.92**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	976,004	971,461	988,368	**978,611**
Q_s	Volumetric flow rate, standard (scfm)	630,041	625,639	637,925	**631,202**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	577,282	576,172	590,245	**581,233**
Total Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.217E-09	8.806E-10	1.270E-09	**1.122E-09**
$E_{lb/hr}$	Rate (lb/hr)	4.214E-02	3.044E-02	4.497E-02	**3.918E-02**
$E_{T/yr}$	Rate (Ton/yr)	1.846E-01	1.333E-01	1.970E-01	**1.716E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.545E-05	1.104E-05	1.612E-05	**1.420E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.602E-05	1.143E-05	1.671E-05	**1.472E-05**
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	9.609E-10	6.872E-10	1.011E-09	**8.864E-10**
$E_{lb/hr}$	Rate (lb/hr)	3.328E-02	2.376E-02	3.581E-02	**3.095E-02**
$E_{T/yr}$	Rate (Ton/yr)	1.458E-01	1.041E-01	1.569E-01	**1.356E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.220E-05	8.618E-06	1.284E-05	**1.122E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.265E-05	8.919E-06	1.331E-05	**1.163E-05**
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.418E-11	4.377E-11	1.196E-11	**2.331E-11**
$E_{lb/hr}$	Rate (lb/hr)	4.912E-04	1.513E-03	4.237E-04	**8.094E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.151E-03	6.628E-03	1.856E-03	**3.545E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.800E-07	5.489E-07	1.519E-07	**2.936E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.867E-07	5.681E-07	1.575E-07	**3.041E-07**
Elemental Mercury Results [1]					
C_{sd}	Concentration (lb/dscf)	2.416E-10	1.496E-10	2.466E-10	**2.126E-10**
$E_{lb/hr}$	Rate (lb/hr)	8.369E-03	5.172E-03	8.732E-03	**7.424E-03**
$E_{T/yr}$	Rate (Ton/yr)	3.666E-02	2.265E-02	3.825E-02	**3.252E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	3.068E-06	1.876E-06	3.130E-06	**2.691E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	3.181E-06	1.942E-06	3.245E-06	**2.789E-06**

[1] Allowable HNO_3-H_2O_2 blank (0.02 ug) calculated at ten (10) times detection limit of 0.002 ug.

RESULTS

Table 2-6:
Unit 2 – Stack – Particulate Matter

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		10:42	13:26	16:50	
Stop Time (approx.)		12:51	15:34	19:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.4	5.4	**5.4**
CO_2	Carbon dioxide (dry volume %)	13.4	13.4	13.4	**13.4**
T_s	Sample temperature (°F)	228	240	231	**233**
B_w	Actual water vapor in gas (% by volume)	11.37	9.96	10.64	**10.66**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	881,383	871,051	883,573	**878,669**
Q_s	Volumetric flow rate, standard (scfm)	678,033	658,683	677,463	**671,393**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	600,934	593,062	605,414	**599,803**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	0.0026	0.0016	0.0021	**0.0021**
$E_{lb/hr}$	Particulate Rate (lb/hr)	13.38	8.20	10.83	**10.80**
$E_{T/yr}$	Particulate Rate (Ton/yr)	58.59	35.92	47.44	**47.32**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	0.0049	0.0030	0.0039	**0.0040**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	0.0051	0.0032	0.0041	**0.0042**
RE	Reduction Efficiency (% Removal)[1]	99.97%	99.97%	99.97%	**99.97%**

[1] Removal efficiency calculated using the F_d-based (lb/MMBtu).

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RESULTS

Table 2-7:
Unit 2 – Stack - Fluoride

Run No.		1	2	3	Average
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		13:06	14:24	16:11	
Stop Time (approx.)		14:15	15:33	17:22	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.7	5.2	5.1	**5.3**
CO_2	Carbon dioxide (dry volume %)	13.4	13.8	13.7	**13.6**
T_s	Sample temperature (°F)	218	220	218	**219**
B_w	Actual water vapor in gas (% by volume)	12.07	11.81	11.32	**11.73**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	909,374	905,251	895,703	**903,443**
Q_s	Volumetric flow rate, standard (scfm)	711,366	706,404	700,672	**706,147**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	625,514	623,006	621,339	**623,287**
Hydrogen Fluoride (HF) Results					
C_{sd}	HF Concentration (ppmdv)	<0.0498	<0.0435	<0.0428	**<0.0454**
$E_{lb/hr}$	HF Rate (lb/hr)	<0.0970	<0.0844	<0.0828	**<0.0881**
$E_{kg/hr}$	HF Rate (kg/hr)	<0.0440	<0.0383	<0.0376	**<0.0399**
$E_{T/yr}$	HF Rate (Ton/yr)	<0.4249	<0.3696	<0.3628	**<0.3857**
E_{Fd}	HF Rate - Fd-based (lb/MMBtu)	<3.4758E-05	<2.9387E-05	<2.8740E-05	**<3.0962E-05**
E_{Fc}	HF Rate - Fc-based (lb/MMBtu)	<3.5800E-05	<3.0358E-05	<3.0097E-05	**<3.2085E-05**

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RESULTS

Table 2-8:
Unit 2 – Stack – PCDD/PCDF

Run No.		1	2	3	Average
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		07:51	11:14	14:42	
Stop Time (approx.)		11:02	14:28	17:52	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.3	5.2	**5.3**
CO_2	Carbon dioxide (dry volume %)	13.6	13.5	13.6	**13.6**
T_s	Sample temperature (°F)	216	213	218	**216**
B_w	Actual water vapor in gas (% by volume)	10.94	11.11	10.92	**10.99**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	868,040	865,842	874,649	**869,510**
Q_s	Volumetric flow rate, standard (scfm)	681,348	682,343	684,230	**682,640**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	606,818	606,531	609,514	**607,621**
Total PCDD/F Results (TEF=1)					
C_{sd}	PCDD/F Concentration (ng/dscm)	2.122E-02	1.714E-02	1.481E-02	**1.772E-02**
$E_{lb/hr}$	PCDD/F Rate (lb/hr)	4.825E-08	3.895E-08	3.382E-08	**4.034E-08**
$E_{g/s}$	PCDD/F Rate (g/s)	6.078E-09	4.906E-09	4.261E-09	**5.082E-09**
$E_{T/yr}$	PCDD/F Rate (Ton/yr)	2.113E-07	1.706E-07	1.481E-07	**1.767E-07**
E_{Fd}	PCDD/F Rate - F_d-based (lb/MMBtu)	1.747E-11	1.402E-11	1.204E-11	**1.451E-11**
E_{Fc}	PCDD/F Rate - F_c-based (lb/MMBtu)	1.808E-11	1.471E-11	1.262E-11	**1.514E-11**
Total PCDD/F TEQ Results (using USEPA/INTL 1989 TEFs)					
C_{sdTEQ}	TEQ Concentration (ng/dscm)	2.141E-04	3.608E-06	2.012E-05	**7.927E-05**
$E_{lb/hrTEQ}$	TEQ Rate (lb/hr)	4.867E-10	8.198E-12	4.596E-11	**1.803E-10**
$E_{g/sTEQ}$	TEQ Rate (g/sec)	6.131E-11	1.033E-12	5.790E-12	**2.271E-11**
$E_{T/yrTEQ}$	TEQ Rate (Ton/yr)	2.132E-09	3.591E-11	2.013E-10	**7.897E-10**
E_{FdTEQ}	TEQ Rate - F_d-based (lb/MMBtu)	1.763E-13	2.952E-15	1.636E-14	**6.520E-14**
E_{FcTEQ}	TEQ Rate - F_c-based (lb/MMBtu)	1.824E-13	3.097E-15	1.715E-14	**6.756E-14**

RESULTS

Table 2-9:
Unit 2 – Stack – Lead

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		10:42	13:26	16:50	
Stop Time (approx.)		12:51	15:34	19:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.4	5.4	**5.4**
CO_2	Carbon dioxide (dry volume %)	13.4	13.4	13.4	**13.4**
T_s	Sample temperature (°F)	228	240	231	**233**
B_w	Actual water vapor in gas (% by volume)	11.37	9.96	10.64	**10.66**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	881,383	871,051	883,573	**878,669**
Q_s	Volumetric flow rate, standard (scfm)	678,033	658,683	677,463	**671,393**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	600,934	593,062	605,414	**599,803**
Lead Results - Total					
C_{sd}	Concentration (lb/dscf)	1.570E-11	4.207E-11	2.222E-11	**2.666E-11**
$E_{lb/hr}$	Rate (lb/hr)	5.659E-04	1.497E-03	8.072E-04	**9.567E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.479E-03	6.556E-03	3.535E-03	**4.190E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	2.070E-07	5.547E-07	2.930E-07	**3.516E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.174E-07	5.826E-07	3.078E-07	**3.693E-07**

RESULTS

Table 2-10:
Unit 2 – Stack – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.2	5.4	5.8	**5.5**
CO_2	Carbon dioxide (dry volume %)	13.4	13.5	13.2	**13.4**
T_s	Sample temperature (°F)	241	250	234	**242**
B_w	Actual water vapor in gas (% by volume)	10.53	10.69	9.98	**10.40**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	907,511	913,697	899,844	**907,017**
Q_s	Volumetric flow rate, standard (scfm)	685,928	681,365	686,707	**684,667**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	613,694	608,500	618,165	**613,453**
Total Mercury Results [1]					
C_{sd}	Concentration (lb/dscf)	5.337E-10	5.867E-10	<5.191E-10	**<5.465E-10**
$E_{lb/hr}$	Rate (lb/hr)	1.965E-02	2.142E-02	<1.925E-02	**<2.011E-02**
$E_{T/yr}$	Rate (Ton/yr)	8.608E-02	9.383E-02	<8.434E-02	**<8.808E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	6.949E-06	7.737E-06	<7.027E-06	**<7.238E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.393E-06	8.066E-06	<7.299E-06	**<7.586E-06**
RE	Reduction Efficiency (% Removal)[2]	63.6%	46.7%	64.3%	**58.2%**
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	5.693E-13	5.666E-13	5.686E-13	**5.682E-13**
$E_{lb/hr}$	Rate (lb/hr)	2.096E-05	2.069E-05	2.109E-05	**2.091E-05**
$E_{T/yr}$	Rate (Ton/yr)	9.182E-05	9.061E-05	9.237E-05	**9.160E-05**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.412E-09	7.472E-09	7.697E-09	**7.527E-09**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.885E-09	7.790E-09	7.995E-09	**7.890E-09**
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	2.562E-12	2.266E-12	<1.706E-12	**<2.178E-12**
$E_{lb/hr}$	Rate (lb/hr)	9.433E-05	8.275E-05	<6.327E-05	**<8.012E-05**
$E_{T/yr}$	Rate (Ton/yr)	4.132E-04	3.624E-04	<2.771E-04	**<3.509E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	3.335E-08	2.989E-08	<2.309E-08	**<2.878E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	3.548E-08	3.116E-08	<2.398E-08	**<3.021E-08**
Elemental Mercury Results [3]					
C_{sd}	Concentration (lb/dscf)	5.306E-10	5.839E-10	5.177E-10	**5.441E-10**
$E_{lb/hr}$	Rate (lb/hr)	1.954E-02	2.132E-02	1.920E-02	**2.002E-02**
$E_{T/yr}$	Rate (Ton/yr)	8.558E-02	9.337E-02	8.410E-02	**8.768E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	6.908E-06	7.700E-06	7.008E-06	**7.205E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.349E-06	8.027E-06	7.279E-06	**7.552E-06**

[1] Allowable HNO_3-H_2O_2 blank (0.02 ug) calculated at ten (10) times detection limit of 0.002 ug.

[2] Removal efficiency calculate using F_d-based (lb/MMBtu)

[3] Non-detect values entered in Total Mercury as 0.5 x ND value

RESULTS

Table 2-11:
Unit 2 – Stack - Ammonia

Run No.		1	2	3	Average
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		08:02	09:42	11:41	
Stop Time (approx.)		09:14	11:28	12:47	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.6	5.4	5.4	**5.5**
CO_2	Carbon dioxide (dry volume %)	13.5	13.6	13.6	**13.6**
T_s	Sample temperature (°F)	220	215	216	**217**
B_w	Actual water vapor in gas (% by volume)	10.81	11.79	11.55	**11.39**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	948,401	971,199	980,558	**966,719**
Q_s	Volumetric flow rate, standard (scfm)	740,076	762,917	769,697	**757,563**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	660,041	672,960	680,798	**671,266**
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (ppmdv)	3.17	0.18	0.15	**1.17**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	5.550	0.326	0.265	**2.047**
$E_{T/yr}$	Ammonia Rate (Ton/yr)	24.31	1.43	1.16	**8.97**
E_{Fd}	Ammonia Rate - Fd-based (lb/MMBtu)	0.0019	0.0001	0.0001	**0.0007**
E_{Fc}	Ammonia Rate - Fc-based (lb/MMBtu)	0.0019	0.0001	0.0001	**0.0007**

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DESCRIPTION OF INSTALLATION

PROCESS DESCRIPTION

The Jacksonville Electric Northside Generating Station Unit 2 consists of a 300 MW circulating fluidized bed (CFB) boiler a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The control system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

The testing reported in this document was performed at the Unit 2 SDA Inlet and Stack locations.

A schematic of the process indicating sampling locations is shown in Figure 3-1.

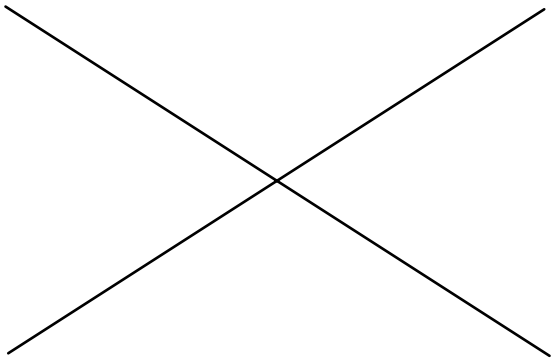


Figure 3-1: Process Schematic

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION(S)

Sampling point locations were determined according to EPA Method 1.

Table 3-1 outlines the sampling point configurations. Figure 3-3 and 3-3 illustrate the sampling points and orientation of sampling ports for each of the sources tested in the program.

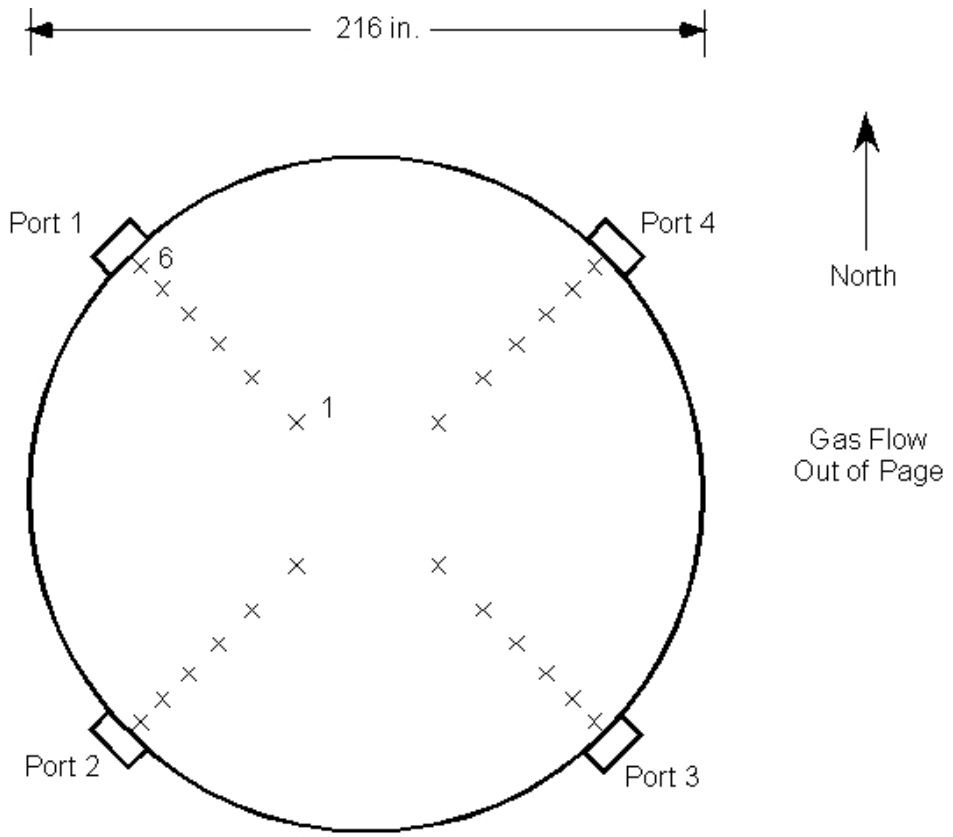
Table 3-1:
Sampling Points

Location	Constituent	Method	Run No.	Ports	Points per Port	Minutes per Point	Total Minutes	Figure
Unit 2 SDA Inlet	SO2	6C	1-6	1	1	60[1]	60	N/A
Unit 2 SDA Inlet	Particulate	17	1-6	4	6	2.5	60	3-1
Unit 2 SDA Inlet	Mercury	OH[2]	1-6	4	6	5	120	3-1
Unit 2 Stack	Particulate	5	1-3	4	3	10	120	3-2
Unit 2 Stack	Fluoride	13B	1-3	4	3	5	60	3-2
Unit 2 Stack	PCDD/PCDF	23	1-3	4	3	15	180	3-2
Unit 2 Stack	Lead	29	1-3	4	3	10	120	3-2
Unit 2 Stack	Mercury	OH[2]	1-6	4	3	10	120	3-2
Unit 2 Stack	Ammonia	CTM-027	1-3	4	3	5	60	3-2

[1] Sulfur Dioxide was sampled from a single point in the duct. Readings were collected at one-second intervals by the computer based data acquisition system and reported as one-minute averages.
[2] Mercury was determined using the Ontario Hydro method.

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



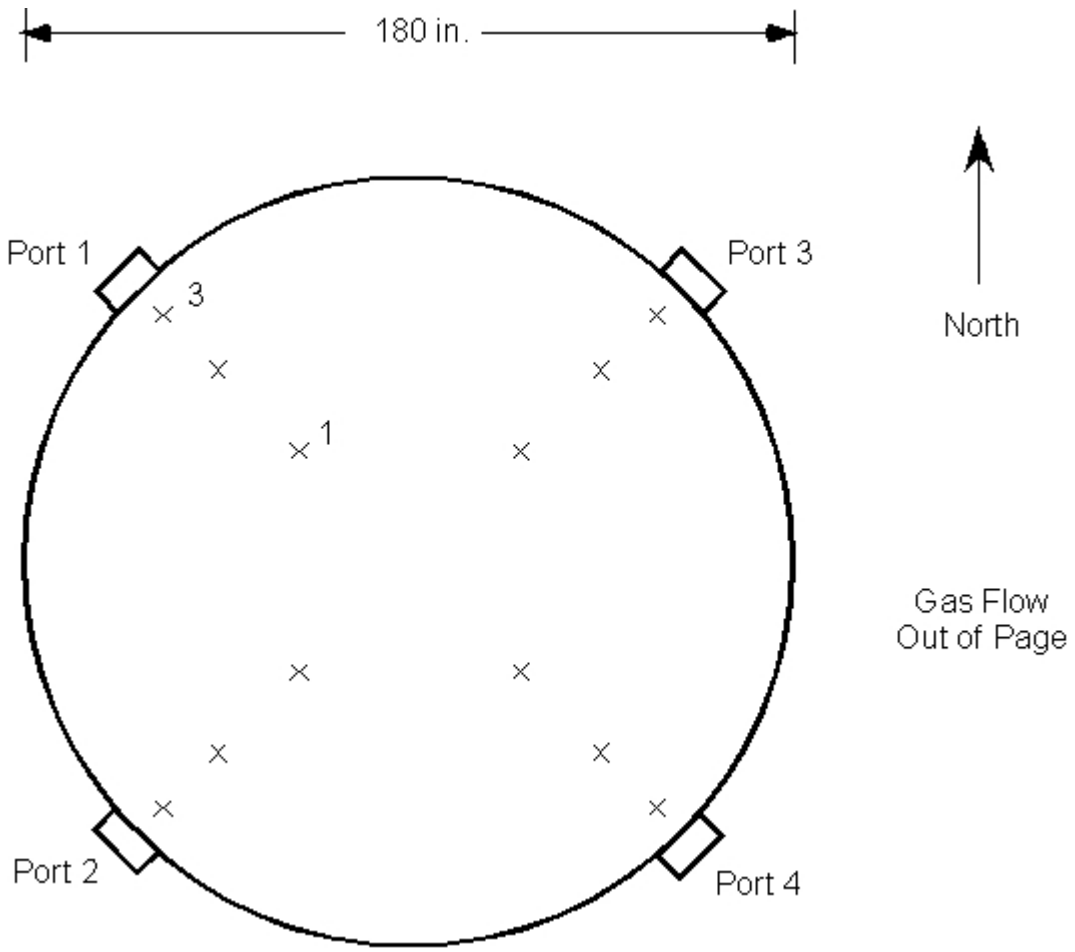
Sampling Point	Port to Point Distance (in.)
1	76.9
2	54.0
3	38.2
4	25.5
5	14.5
6	4.5

Diameters to upstream disturbance: >2.0 — Limit: 2.0 (minimum)
Diameters to downstream disturbance: >0.5 — Limit: 0.5 (minimum)

Figure 3-2: SDA Inlet Sampling Point Determination (EPA Method 1)

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



Sampling Point	Port to Point Distance (in.)
1	53.3
2	26.3
3	7.9

Diameters to upstream disturbance: >8.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >2.0 Limit: 0.5 (minimum)

Figure 3-3: Stack Sampling Point Determination (EPA Method 1)

METHODOLOGY

Clean Air Engineering followed procedures as detailed in U.S. Environmental Protection Agency (EPA) Methods 1, 2, 3A, 4, 5, 6C, 13B, 23, 29, Conditional Test Method CTM-027 and the Ontario Hydro Method. The following table summarizes the methods and their respective sources.

Table 4-1:
Summary of Sampling Procedures

Title 40 CFR Part 60 Appendix A	
Method 1	"Sample and Velocity Traverses for Stationary Sources"
Method 2	"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)"
Method 3A	"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 4	"Determination of Moisture Content in Stack Gases"
Method 5	"Determination of Particulate Emissions from Stationary Sources"
Method 6C	"Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 13B	"Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)"
Method 23	"Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources"
Method 29	"Determination of Metals Emissions from Stationary Sources"
Conditional Test Method	
CTM-027	"Procedure for the Collection and Analysis of Ammonia in Stationary Sources."
Draft Methods	
Ontario Hydro	"Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources."

The EPA Methods (1 through 29) appear in detail in Title 40 of the Code of Federal Regulations (CFR). The Conditional Test Method and the Hydro Ontario Method appear in detail on the US EPA Emissions Measurement Center web page. All methods may be found on the World Wide Web at http://www.cleanair.com.

Diagrams of the sampling apparatus and major specifications of the sampling, recovery and analytical procedures are summarized for each method in Appendix A.

Clean Air Engineering followed specific quality assurance and quality control (QA/QC) procedures as outlined in the individual methods and in USEPA "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III Stationary Source-Specific Methods", EPA/600/R-94/038C. Additional QA/QC methods as prescribed in Clean Air's internal Quality Manual were also followed. Results of all QA/QC activities performed by Clean Air Engineering are summarized in Appendix D.

APPENDIX

TEST METHOD SPECIFICATIONS ..... A
SAMPLE CALCULATIONS ..... B
PARAMETERS C
QA/QC DATA ..... D
FIELD DATA ..... E
FIELD DATA PRINTOUTS ..... F
LABORATORY DATA ..... G
FACILITY OPERATING DATA ..... H

ATTACHMENT D

PI Data Summary

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air	Avg. Out A and B, Deg F	104.3	102.8
	Average, deg F	109.0	108.3
	Count	480	480
	Standard Deviation	4.3537	3.4784
Secondary Air	Total SA flow, klb/hr	0.8300	0.8215
	Average, Total SA Flow, klb/hr	0.8170	0.8222
	Count	240	240
	Standard Deviation	0.0110	0.0090
	Avg. Out A and B, Deg F	97.2	95.4
	Average, deg F	101.3	102.3
	Count	480	480
	Standard Deviation	2.3087	3.7724
Fuel	Total Flow, klb/hr	207.8	206.5
	Average, deg F	207.6	206.9
	Count	240	240
	Standard Deviation	0.1874	0.2361
PAHTR Gas Out	Gas Out, deg F, A train	308.3	302.3
	Gas Out, deg F, B train	326.2	320.6
	Average, deg F	314.5	313.6
	Count	480	480
	Standard Deviation	8.6833	9.1275
SAHTR Gas Out	Gas Out, deg F, A train	279.1	274.1
	Gas Out, deg F, B train	290.2	287.1
	Average, deg F	287.8	287.7
	Count	480	480
	Standard Deviation	10.9188	11.1038
PAH Gas In	Gas In, deg F, A & B train	587.0	579.7
	Average, deg F	575.7	576.6
	Count	240	240
	Standard Deviation	6.3042	4.1497
SAH Gas In	Gas In, deg F A & B train	590.2	583.0
	Average, deg F	578.6	579.9
	Count	240	240
	Standard Deviation	6.3563	4.3556
PAH Air Out	Air Out, deg F A & B train	482.4	474.8
	Average, deg F	475.0	473.5
	Count	240	240
	Standard Deviation	4.6017	3.1539
SA Airheater Air Out	Air Out, deg F A & B train	429.9	424.5
	Average, deg F	424.0	424.7
	Count	240	240
	Standard Deviation	3.9809	2.8573

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
	Ash leaving temperature, deg F, A	0	423.8745
	Ash leaving temperature, deg F, B	0	0
Stripper/	Ash leaving temperature, deg F, C	0	0
Coolers - A, B,	Ash leaving temperature, deg F, D	382.1	376.1
C, D	Average, deg F	398.1	462.8
	Count	480	254
	Standard Deviation	6.8019	25.3686
	Temperature, deg F		
SDA Hopper	Average, deg F	215.1	184.3
	Count	240	240
	Standard Deviation	7.8791	5.8660
	Feedrate, feeders 1, 2, 3, klb/hr	59.9	53.2
Limestone	Average, klb/hr	57.6	54.6
Feed Rate 1	Count	240	240
	Standard Deviation	4.1078	4.4497
	AH inlet, ppm		
SO2, in flue	Average, ppm mv	40.7	41.1
Gas	Count	240	240
	Standard Deviation	12.7747	11.0049
	Flow to A, B, C, klb/hr	36043.7	36367.3
Intrex Blower	Average, klb/hr	35970.0	36289.4
Air Flow	Count	1440	1440
	Standard Deviation	135.2805	84.9352
	PA Flow to Intrex A, B, C, klb/hr	44614.8	44838.0
Intrex Seal Pot	Average, klb/hr	44702.2	45476.7
Blower	Count	240	240
	Standard Deviation	211.5243	191.6591
Intrex Blower	Average, deg F	164.2	164.8
Exit Air Temp	Count	240	240
	Standard Deviation	3.1128	3.8639
Seal Pot	Average, deg F	177.6	179.0
Blower Exit Air	Count	240	240
Temp	Standard Deviation	2.3340	3.2261
Feedwater	Average, deg F	484.5	484.1
Temperature to	Count	240	240
Econ	Standard Deviation	0.5612	0.5413
Feedwater	Average, psiG	2177.3	2030.0
Pressure to	Count	240	240
Econ	Standard Deviation	6.1670	5.8581
(DSH)SH-1	Average, klb/hr	11.2	30.0
Spray Flow	Count	240	240
	Standard Deviation	2.2235	4.3873

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
SH-1 Spray Temperature	Average, deg F	305.0	308.1
	Count	240	240
	Standard Deviation	0.9412	1.2058
SH-1 Spray Pressure	Average, psiG	2707.7	2697.7
	Count	240	240
	Standard Deviation	5.0183	4.3845
Drum Pressure	Average of three pressure values	2565.5	2558.0
	Average, psiG	2564.6	2560.0
	Count	720	720
	Standard Deviation	4.4214	3.3911
Main Steam Temperature	Average, deg F	1003.3	1003.4
	Count	240	240
	Standard Deviation	0.7794	0.8207
Main Steam Pressure	Average of two pressure values	2400.6	2400.5
	Average, psiG	2400.4	2400.5
	Count	480	480
	Standard Deviation	3.1311	2.7904
Reheater Outlet Temperature	Average of three temp values	1001.3	1003.9
	Average, deg F	1000.0	1001.9
	Count	720	720
	Standard Deviation	1.0939	1.3519
Reheater Outlet Pressure	Average of two pressure values	571.7	568.7
	Average, psiG	570.9	568.8
	Count	480	480
	Standard Deviation	25.2664	25.2064
CRH Ent Attemp Temp	Average, deg F	607.5	607.2
	Count	240	240
	Standard Deviation	0.8773	1.1088
CRH Ent Attemp Press	Average, psiG	570.5	568.2
	Count	240	240
	Standard Deviation	3.5904	3.4197
RH Spray Flow	Average, klb/hr	0.5	0.5
	Count	240	240
	Standard Deviation	0.0750	0.0780
RH Spray Temp	Average, deg F	186.6	188.6
	Count	240	240
	Standard Deviation	1.0044	0.8165
RH Spray Pressure	Average, psiG	727.4	725.6
	Count	240	240
	Standard Deviation	1.2194	1.1281

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Htr 1 FW Entering Temp	Data	417.8	417.3
	Data	484.7	483.8
	Average, deg F	451.1	450.7
	Count	480	480
	Standard Deviation	33.4367	33.3596
Htr 1 FW Entering Pressure	Data	2186.7	2039.6
	Data	2186.7	2039.6
	Average, psiG	2177.3	2030.0
	Count	480	480
	Standard Deviation	6.1606	5.8520
Htr 1 FW Leaving Temp	Average, deg F	484.5	484.1
	Count	240	240
	Standard Deviation	0.5612	0.5413
Htr 1 FW Leaving Pressure	Average, psiG	2177.3	2030.0
	Count	240	240
	Standard Deviation	6.1670	5.8581
Htr 1 Extraction Stm Temp	Average, deg F	632.1	631.9
	Count	240	240
	Standard Deviation	0.8084	1.0135
Htr 1 Extraction Stm Pressure	Average, psiG	573.8	571.5
	Count	240	240
	Standard Deviation	3.4706	3.3074
Htr 1 Drain Temp	Average, deg F	423.1	422.8
	Count	240	240
	Standard Deviation	0.4722	0.4885
Htr 1 Drain Pressure	Average, psiG	573.8	571.5
	Count	240	240
	Standard Deviation	3.4706	3.3074
Feedwater to Econ	Pressure, psiG	2201.6	2039.6
	Temperature, deg F	484.7	483.8
	Density, lb / cu. ft.	0.01980	0.01981
Primary Air to SC A	Total of three flow values	40.3	27.7
	Average, k lb/hr	39.5	27.5
	Count	240	240
	Standard Deviation	2.2858	0.1828
Primary Air to SC B	Total of three flow values	10.3	10.4
	Average, k lb/hr	10.3	10.4
	Count	240	240
	Standard Deviation	0.0680	0.0573
Primary Air to SC C	Total of three flow values	18.3	18.0
	Average, k lb/hr	17.8	18.2
	Count	240	240
	Standard Deviation	2.5480	0.1116

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air to SC D	Total of three flow values	31.7	31.3
	Average, k lb/hr	31.3	31.7
	Count	240	240
	Standard Deviation	0.2770	0.2094
Combustion Air Flow into PAH (hot), lb/hr	Total of fourteen flow values	13865.3	13984.3
	Average, k lb/hr	13733.0	13872.9
	Count	240	240
	Standard Deviation	85.3431	90.1078
Combustion Air Flow bypassing PAH (cold), lb/hr	Total of four flow values	47.5	37.7
	Average, k lb/hr	45.0	38.0
	Count	240	240
	Standard Deviation	3.9395	0.2002
Total air Flow, klb/hr	Average, k lb/hr	2435.7	2436.0
	Count	240	240
	Standard Deviation	9.3840	8.1778

ATTACHMENT E

Abbreviation List - Refer to Section 1.2

ATTACHMENT F

Isolation Valve List

Hole #	Description	Approximate Location	Closed (Yes / No)			
			13-Jan-04	14-Jan-04	15-Jan-04	16-Jan-04
37	RHA to CRH	Next to Heat 1	closed	closed	closed	closed
Use Digital Readout	MS Bypass to CRH (Upstream)	Next to Heater 1	closed	closed	closed	closed
38	Desup Wtr from BFP Disch to MS Bypass		closed	closed	closed	closed
Bare Pipe	Heater 1 ~~Running~~ Vent	On Side of Heater 1	closed	closed	closed	closed
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	closed	closed	closed	closed
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	closed	closed	closed	closed
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	closed	closed	closed	closed
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	closed	closed	closed	closed
33	Aux Steam Header (GRAY Valve) 337	Platform Overhead	closed	closed	closed	closed
55	CRH Line Drains - common line	Below Turbine	closed	closed	~~open~~ closed	closed
56	CRH Line Drains - common line	Below Turbine	closed	closed	closed	closed
57	CRH Line Drains - North	Below Turbine	closed	closed	closed	closed
58	CRH Line Drains - South	Below Turbine	closed	closed	closed	closed
60	MS Line Drain	Below Turbine	closed	closed	closed	closed
61	MS Line Drain	Below Turbine	closed	closed	closed	closed
#1	Extraction Drain	Below Turbine	closed	closed	closed	closed
	Heat Soak Valve SA330	Below Turbine	closed	closed	closed	closed

#1 Heater Shell Drain balking small amount

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
Mezzanine Level			
35	DA Pegging Steam (Upstream)	Next to Heater 1	
36	DA Pegging Steam (Downstream)	Next to Heater 1	
34	DA Pegging Steam Line Drain	Next to Heater 1	
37	RHA to CRH	Next to Heater 1	
39	MS Bypass to CRH (Upstream)	Over railing by Heater 1	
Use Digital Readout	MS Bypass to CRH (Downstream)	Next to Heater 1	
38	Desup Wtr from BFP Disch to MS Bypass	Near railing by Heater 1	
Bare Pipe	Heater 1 Running Vent	On Side of Heater 1	
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	
Visual	Heater 1 FW Bypass	Directly above Heater 1	
Bare Pipe	Heater 2 Running Vent	On Side of Heater 2	
Bare Pipe	Heater 2 Relief Vent	Top of Heater 2	
Visual	Heater 2 FW Bypass	Directly above Heater 2	
41	Aux Steam to Unit 3 CRH	Against wall - stairs near Htr 5	
40	Aux Steam from Unit 3 CRH	Against wall - stairs near Htr 5	
42	MS to SSH	Platform (overhead)	
43	SSR Bypass Line	Platform (overhead)	
44	Aux Steam Supply Line to SSR	Vertical Pipe near Platform	
Gauge	SSH Pressure	Board on Platform	
45	Heater 4 Running Vent	Side of Heater 4	
Bare Pipe	Heater 4 Relief Vent	Top of Heater 4	
Visual	Heater 4 FW Bypass	Directly above Heater 4	
46	Heater 5 Vent	Side of Heater 5	
47	Heater 5 Vent	Side of Heater 5	
Bare Pipe	Heater 5 Relief Vent	Top of Heater 5	
Visual	Heater 5 FW Bypass	Directly above Heater 5	
48	CBP Disch to BFP Suction	To the side of Heater 5	
Visual	Heater 6 FW Bypass	Near Condenser Wall	
19	BDV to Cond	Near Condenser Wall (right side)	
20	RFDV (Ventilator Valve) to Cond	Bare Pipe near Cond Wall (R/S)	
21	Equalizer Valve to Cond (CRV-1)	Bare Pipe near Cond Wall (R/S)	
22	Equalizer Valve to Cond (CRV-2)	Bare Pipe near Cond Wall (R/S)	
12	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
14	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
52	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
53	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
13	Stm Lead Drains	Near Condenser Wall (R/S)	
16	Stm Lead Drains	Near Condenser Wall (R/S)	
17	Stm Lead Drains	Near Condenser Wall (R/S)	
18	Stm Lead Drains	Near Condenser Wall (R/S)	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
15	CRV Drain Lines	Near HRH Line	
23	CRV Drain Lines	Hear HRH Line	
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	
DCS	HRH Bypass to Condenser (Downstream)	Control Room	
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	
Visual	SDBFP Recirc to DA	Near HRH Bypass Line	
Visual	MDBFP Recirc to DA	Near HRH Bypass Line	
	Condenser Vacuum		

Ground Floor

24	TDV to Cond (SS Dump)	Into Condenser (use platform)	
7	CRH Drain Hdr 1	Hdr into Cond on Left Side	
8	MS Drain Hdr 2	Hdr into Cond on Left Side	
6	Extraction Drain Hdr 3	Hdr into Cond on Left Side	
10	Drain Hdr 4	Hdr into Cond on Right Side	
9	Drain Hdr 5	Hdr into Cond on Right Side	
11	Steam Lead Drains	Bare Pipe - Side of Condenser	
51	BAC Return to Condenser (CV-4)	U/S of CV-4	
Double Isolate	Hotwell Makeup		
	Polisher Drains	Near Condensate Polishing Sys	
	Bitter Water Pump Off	Near Condensate Polishing Sys	Yes / No
	Unit 2 Fill Pump Off	Near Condensate Polishing Sys	Yes / No
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	/
2	Htr 6 Dump to Cond	Upstream of Valve	
3 / 26	Htr 2 Dump to Cond	Up/Downstream of Valve	/
4 / 27	Htr 4 Dump to Cond	Up/Downstream of Valve	/
5 / 28	Htr 5 Dump to Cond	Up/Downstream of Valve	/
29	Aux Stm to CRH Warm. (U/S of Check Vlv)	Platform Overhead	
30	Aux Stm to CRH Warm. (D/S of Check Vlv)	Platform Overhead	
31	Aux Steam to/from Unit 3 CRH	Platform Overhead	
32	Aux Steam to SSH	Platform Overhead	
33	Aux Steam Header Gray Valve	Platform Overhead	
54	HRH Line Drains	Below Turbine	
59	HRH Line Drains	Below Turbine	
55	CRH Line Drains - common line	Below Turbine	
56	CRH Line Drains - common line	Below Turbine	
57	CRH Line Drains - North	Below Turbine	
58	CRH Line Drains - South	Below Turbine	
60	MS Line Drain	Below Turbine	
61	MS Line Drain	Below Turbine	
	#1 Extr Drain Heat Soak Valve	Below Turbine	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
	Hotwell Make-Up Valves		
	Boiler Blow Down Valve		
	Valve SA 328 (turbine soak line)		
	Auxiliary Steam Supply to Seal Steam System		
	Valve 331 Auxiliary Steam from Cold RH		
	Reheat Attemperator		
	Heater #1 Continuous Vent		
	Heater #2 Continuous Vent		
	Heater #4 Continuous Vent		
	Heater #5 Continuous Vent		

ATTACHMENT G

Fuel Analyses - Pittsburgh 8 Coal

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY FUEL ANALYSES

Fuel	Unit #2 Jan. 13, 2004					
Lab Number	32006-01A	32006-02B	32006-03C	32006-04D	32006-05E	Average Values
Date	1/13/2004	1/13/2004	1/13/2004	1/13/2002	1/13/2004	
Time	11:00 - 11:20	12:00 - 12:20	13:00 - 13:20	14:00 - 14:20	15:00 - 15:20	
Proximate Analysis						
Moisture, wt% (±0.25)	6.59	7.47	7.17	7.23	7.82	7.256
Ash, wt% (±0.49)	7.48	6.76	7.67	6.02	6.51	6.89
Volatile, wt% (±1.0)	49.4	54.29	57.06	55.77	55.78	54.46
Fixed Carbon, wt% (±1.0)	36.53	30.48	28.10	30.98	29.89	31.20
Ultimate Analysis						
Carbon, wt% (±2.51)	73.1	73.36	70.17	73.77	73.08	72.70
Hydrogen, wt% (±0.30)	4.97	4.87	4.62	5.01	4.72	4.84
Nitrogen, wt% (±0.17)	1.28	1.35	1.33	1.49	1.4	1.37
Sulfur, wt% (±0.009)	4.89	4.86	4.82	4.84	4.8	4.84
Moisture, wt% (±0.25)	6.59	7.47	7.17	7.23	7.82	7.26
Ash, wt% (±0.49)	7.48	6.76	7.67	6.02	6.51	6.89
Oxygen, wt% (±2.51)	1.69	1.33	4.22	1.64	1.67	2.11
Higher Heating, Btu/lb (±107 Btu/lb)	12,874	12,972	12,770	12,886	12,885	12,877
Total Chlorine, wt% (±200 ug/g)	0.18	0.23	0.12	0.25	0.10	0.18
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Moisture (oven), wt% (±1.0)	6.59	7.47	7.17	7.23	7.82	7.26
Ash elemental analysis						
SiO_2, wt% (±0.65)	0.42	0.33	0.30	0.30	1.22	0.51
Al_2O_3, wt% (±0.98)	48.75	49.90	47.57	65.98	53.51	53.14
Fe_2O_3, wt% (±1.44)	19.55	18.62	17.19	12.18	18.15	17.14
CaO, wt% (±4.74)	18.96	19.67	23.92	8.86	16.86	17.65
MgO, wt% (±1.25)	3.84	3.59	3.70	3.00	3.02	3.43
Na_2O, wt% (±3.70)	4.27	3.58	2.84	2.52	2.75	3.19
K_2O, wt% (±4.25)	3.42	3.53	3.63	6.99	3.47	4.21
Ti_2O, wt% (±1.52)	0.78	0.78	0.85	0.17	1.02	0.72
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	25.63	9.29	7.96	11.35	15.88	14.02
Particulate Left Mesh, 1/4", wt%	14.27	18.77	14.81	20.37	29.10	19.46
Particulate Left Mesh, #4, wt%	30.06	10.97	10.88	10.52	9.95	14.48
Particulate Left Mesh, #8, wt%	9.44	22.40	19.67	21.82	17.72	18.21
Particulate Left Mesh, #14, wt%	6.43	13.84	17.19	13.66	11.13	12.45
Particulate Left Mesh, #28, wt%	6.78	12.61	16.76	12.48	9.22	11.57
Particulate Left Mesh, #50, wt%	3.84	5.82	7.44	5.84	4.11	5.41
Particulate Left Mesh, #100, wt%	1.94	4.04	3.69	2.43	1.41	2.70
Bottom, wt%	0.56	1.38	0.57	0.33	0.41	0.65

JEA Northside Unit 2
Test #1 - Pittsburgh 8 Coal
SUMMARY - FUEL ANALYSES

Fuel	Unit #2 Jan. 14, 2004					
Lab Number	31991-01A	31991-02B	31991-03C	31991-04D	31991-05E	Average Values
Date	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	
Time	10:00 - 10:15	11:00 - 11:15	12:00 - 12:15	13:00 - 13:15	14:00 - 14:15	
Proximate Analysis						
Moisture, wt% (±0.25)	7.28	7.25	7.80	7.32	7.29	7.388
Ash, wt% (±0.49)	6.16	7.17	7.30	6.93	7.74	7.06
Volatile, wt% (±1.0)	54.91	55.69	54.14	54.31	56.63	55.14
Fixed Carbon, wt% (±1.0)	31.65	29.89	30.76	31.44	28.34	30.42
Ultimate Analysis						
Carbon, wt% (±2.51)	72.15	70.10	73.51	73.49	72.49	72.35
Hydrogen, wt% (±0.30)	4.50	4.65	4.93	4.84	4.66	4.72
Nitrogen, wt% (±0.17)	1.32	1.32	1.39	1.45	1.28	1.35
Sulfur, wt% (±0.009)	4.60	4.70	3.82	4.83	4.84	4.56
Moisture, wt% (±0.25)	7.28	7.25	7.80	7.32	7.29	7.39
Ash, wt% (±0.49)	6.16	7.17	7.30	6.93	7.74	7.06
Oxygen, wt% (±2.51)	3.81	4.81	1.25	1.14	1.71	2.54
Higher Heating, Btu/lb (±107 Btu/lb)	13,044	12,864	12,930	12,952	13,060	12,970
Total Chlorine, wt% (±200 ug/g)	0.13	0.15	0.13	0.15	0.13	0.14
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.000	0.000	0.000	0.001	0.001	0.00
Total Lead, ug/g (±9 ug/g)	0.002	0.002	0.002	0.006	0.000	0.00
Moisture (oven), wt% (±1.0)	7.28	7.25	7.80	7.32	7.29	7.39
Ash elemental analysis						
SiO_2, wt% (±0.65)	0.60	0.21	0.37	0.56	0.37	0.42
Al_2O_3, wt% (±0.98)	53.66	40.91	50.60	54.99	53.45	50.72
Fe_2O_3, wt% (±1.44)	15.10	17.31	19.78	17.42	15.83	17.09
CaO, wt% (±4.74)	19.32	32.35	18.25	14.84	18.49	20.65
MgO, wt% (±1.25)	3.08	3.14	3.29	3.23	3.48	3.24
Na_2O, wt% (±3.70)	3.29	2.50	3.28	3.77	3.55	3.28
K_2O, wt% (±4.25)	3.84	2.74	3.42	3.98	3.95	3.59
Ti_2O, wt% (±1.52)	1.11	0.84	1.01	1.21	0.88	1.01
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	1.21	2.61	7.96	11.35	15.88	7.80
Particulate Left Mesh, 1/4", wt%	16.27	18.30	14.81	20.37	29.10	19.77
Particulate Left Mesh, #4, wt%	13.68	5.89	10.88	10.52	9.95	10.18
Particulate Left Mesh, #8, wt%	24.28	27.90	19.67	21.82	17.72	22.28
Particulate Left Mesh, #14, wt%	18.25	17.53	17.19	13.66	11.13	15.55
Particulate Left Mesh, #28, wt%	13.95	17.60	16.76	12.48	9.22	14.00
Particulate Left Mesh, #50, wt%	6.94	6.36	7.44	5.84	4.11	6.14
Particulate Left Mesh, #100, wt%	3.73	1.93	3.69	2.43	1.41	2.64
Bottom, wt%	0.69	0.41	0.57	0.33	0.41	0.48

ATTACHMENT H

Limestone Analyses

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Unit #2 Jan. 13, 2004					
Lab number	31987-01A	31987-02B	31987-03C	31987-04D	31987-05E	Average Values
Date	1/13/2004	1/13/2004	1/13/2004	1/13/2004	1/13/2004	
Time	11:45	12:45	13:45	14:45	15:45	
Compound analysis						
$CaCO_3$, wt% (±0.41)	90.67	85.50	92.38	94.05	91.70	90.86
$MgCO_3$, wt% (±0.41)	3.66	3.04	2.99	3.09	3.77	3.31
Moisture (oven), wt% (±1.0)	0.27	1.26	0.31	0.30	0.29	0.49
Inerts (subtraction), wt% (±1.0)	5.40	10.20	4.32	2.56	4.24	5.34
Total Chlorine, wt% (±200 ug/g)	0.13	0.16	0.15	0.20	0.19	0.17
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.020	0.008	0.005	0.005	0.004	0.01
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.07	0.07	0.08	0.06	0.07	0.07
K, wt% (±0.5 ug/g)	0.02	0.02	0.02	0.02	0.03	0.02
Particulate size distribution						
Particulate Left Mesh, #8, wt%	37.87	38.30	39.66	26.06	34.11	35.20
Particulate Left Mesh, #14, wt%	21.01	18.70	18.01	18.58	18.51	18.96
Particulate Left Mesh, #28, wt%	19.90	16.11	14.49	17.51	18.51	17.30
Particulate Left Mesh, #50, wt%	7.52	7.35	7.22	9.87	9.23	8.24
Particulate Left Mesh, #100, wt%	4.70	6.46	6.46	13.69	6.51	7.56
Particulate Left Mesh, #200, wt%	5.32	6.73	6.73	9.75	9.61	7.63
Particulate Left Mesh, #270, wt%	3.69	4.60	4.60	2.33	2.37	3.52
Bottom, wt%	1.78	0.98	0.99	1.16	1.15	1.21
Conversion Fraction	85.16	84.48	85.41	85.55	86.88	85.50

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Unit #2 Jan. 14, 2004					
Lab number	31989-01A	31989-02B	31989-03C	31989-04D	31989-05E	Average Values
Date	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	
Time	10:15	11:15	12:15	13:15	14:15	
Compound analysis						
$CaCO_3$, wt% (±0.41)	89.46	90.57	94.91	93.06	91.04	91.81
$MgCO_3$, wt% (±0.41)	2.93	3.03	2.97	3.07	2.74	2.95
Moisture (oven), wt% (±1.0)	0.30	0.30	0.32	0.36	0.41	0.34
Inerts (subtraction), wt% (±1.0)	7.31	6.09	1.80	3.51	5.81	4.90
Total Chlorine, wt% (±200 ug/g)	0.02	0.02	0.02	0.03	0.03	0.02
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.006	0.004	0.005	0.004	0.005	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Particulate size distribution						
Particulate Left Mesh, #8, wt%	22.25	24.39	28.52	26.41	31.21	26.56
Particulate Left Mesh, #14, wt%	16.33	14.29	16.26	17.45	16.59	16.18
Particulate Left Mesh, #28, wt%	18.58	18.40	18.37	19.57	13.93	17.77
Particulate Left Mesh, #50, wt%	11.77	12.15	10.94	9.24	13.29	11.48
Particulate Left Mesh, #100, wt%	7.54	6.80	6.44	6.56	5.07	6.48
Particulate Left Mesh, #200, wt%	7.11	5.77	4.70	5.40	4.07	5.41
Particulate Left Mesh, #270, wt%	11.70	11.50	8.87	9.32	9.59	10.20
Bottom, wt%	3.87	5.60	4.37	4.56	4.99	4.68
Conversion Fraction	89.10	89.30	89.54	85.34	90.06	88.67

ATTACHMENT I

Bed Ash Analyses

JEA Northside Unit 2
Test #1 - Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Unit #2 Jan. 13, 2004					
Lab Number	31986-04	31986-05	31986-08	31986-09	31986-11	Average Values
Date	1/13/2004	1/13/2004	1/13/2004	1/13/2004	1/13/2004	
Time	11:00	12:00	13:00	14:00	15:00	
Unburned carbon, wt%	0.12	0.03	0.04	0.10	0.10	0.08
Compound analysis						
CaSO4, wt% (±0.2)	12.91	14.07	13.38	13.45	14.29	13.62
Sulfur, wt% (±0.09)	0.44	0.48	0.46	0.48	0.49	0.47
Ash compound analysis						
SiO2, wt% (±0.65)	2.03	1.84	1.75	2.83	1.91	2.07
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	54.22	60.21	58.42	54.49	61.18	57.71
CaO, wt% (±4.74) (Not Part of Normalization)	20.87	20.96	20.84	21.30	21.14	21.02
MgO, wt% (±1.25)	38.42	30.59	30.30	33.34	31.27	32.78
Na2O, wt% (±3.70)	3.05	4.85	7.15	7.17	3.88	5.22
K2O, wt% (±4.25)	2.04	1.99	1.74	1.63	1.43	1.77
Vanadium, wt% (±1.0)	0.21	0.48	0.57	0.46	0.30	0.41
Nickel, wt% (±1.0)	0.02	0.05	0.07	0.06	0.03	0.05
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.02	0.03	0.03	0.01	0.02
K, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	0.41	0.00	0.41	0.41	0.69	0.39
Particulate Left Mesh, #4, wt%	0.41	0.41	0.39	0.40	0.88	0.50
Particulate Left Mesh, #8, wt%	5.73	8.20	5.02	5.95	11.09	7.20
Particulate Left Mesh, #14, wt%	8.30	11.18	7.77	8.85	13.96	10.01
Particulate Left Mesh, #28, wt%	20.95	21.64	21.96	22.53	27.25	22.87
Particulate Left Mesh, #48, wt%	22.49	20.58	23.74	23.53	20.28	22.12
Particulate Left Mesh, #100, wt%	23.21	21.43	23.52	22.66	15.89	21.34
Particulate Left Mesh, #200, wt%	17.73	16.19	16.30	14.82	8.89	14.79
Bottom, wt%	0.10	0.05	0.11	0.09	0.05	0.08

JEA Northside Unit 2
Test #1 - Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Unit #2 Jan. 14, 2004						
Lab Number	31986-01	31986-02	31986-03	31986-06	31986-07	31986-10	Average Values
Date	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	
Time	10:00	10:20	11:00	12:15	13:00	14:15	
Unburned carbon, wt%	0.04	0.04	0.02	0.02	0.09	0.06	0.05
Compound analysis							
CaSO4, wt% (±0.2)	14.66	14.43	14.60	12.03	14.07	14.20	14.00
Sulfur, wt% (±0.09)	0.50	0.50	0.51	0.42	0.49	0.48	0.48
Ash compound analysis							
SiO2, wt% (±0.65)	2.92	2.95	2.51	2.94	2.17	2.16	2.61
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	45.30	53.12	56.62	61.31	62.04	46.07	54.08
CaO, wt% (±4.74) (Not Part of Normalization)	21.17	21.49	20.80	20.55	20.96	21.35	21.05
MgO, wt% (±1.25)	43.13	38.29	33.92	29.50	26.30	43.44	35.76
Na2O, wt% (±3.70)	5.66	3.93	4.93	4.52	6.26	5.56	5.14
K2O, wt% (±4.25)	2.58	1.34	1.51	1.30	2.69	2.30	1.95
Vanadium, wt% (±1.0)	0.37	0.33	0.45	0.38	0.48	0.43	0.41
Nickel, wt% (±1.0)	0.04	0.03	0.06	0.05	0.06	0.03	0.04
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.01	0.01	0.02	0.02	0.03	0.02	0.02
K, wt% (±0.5 ug/g)	0.01	0.00	0.01	0.01	0.01	0.01	0.01
Particulate size distribution							
Particulate Left Mesh, 1/2", wt%	0.00	0.41	1.37	0.14	0.00	0.27	0.37
Particulate Left Mesh, #4, wt%	0.34	0.47	0.34	0.41	0.38	0.30	0.37
Particulate Left Mesh, #8, wt%	4.68	6.21	3.49	5.96	3.58	4.44	4.73
Particulate Left Mesh, #14, wt%	8.55	9.10	6.02	8.81	5.78	7.22	7.58
Particulate Left Mesh, #28, wt%	26.65	22.44	17.91	22.70	18.77	20.83	21.55
Particulate Left Mesh, #48, wt%	26.81	21.94	20.42	23.77	21.63	23.80	23.06
Particulate Left Mesh, #100, wt%	22.94	22.22	25.12	22.78	25.71	24.62	23.90
Particulate Left Mesh, #200, wt%	9.04	16.35	24.00	14.74	23.61	17.76	17.58
Bottom, wt%	0.07	0.09	0.13	0.09	0.13	0.11	0.10

ATTACHMENT J

Flyash (Air Heater and PJFF) Analyses

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY FLYASH ANALYSES

Flyash	Unit #2 Jan. 13, 2004						
Lab Number	31990-05 (Bag House)	31990-07 (Bag House)	31990-10 (Bag House)	31990-14 (Bag House)	31990-16 (Bag House)	32065-01A (Isokinetic)	Average Values
Time	11:52	12:12	13:20	14:29	15:30		
Unburned carbon, wt%	6.88	6.90	7.17	7.68	8.27	7.86	7.38
Compound analysis							
CaSO4, wt% (±0.2)	34.83	38.80	34.04	35.16	37.35	19.80	36.04
Sulfur, wt% (±0.09)	1.25	1.38	1.22	1.26	1.33	0.73	1.29
Ash compound analysis							
SiO2, wt% (±0.65)	0.22	0.25	0.18	0.15	0.12	0.13	0.18
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	60.64	60.59	62.56	63.68	63.19	56.68	62.13
CaO, wt% (±4.74) (Not Part of Norma	20.80	20.77	20.87	20.81	20.77	21.04	20.80
MgO, wt% (±1.25)	4.49	4.15	3.68	3.25	3.34	3.94	3.78
Na2O, wt% (±3.70)	7.10	7.28	6.52	6.09	6.34	9.63	6.67
K2O, wt% (±4.25)	6.57	6.79	6.14	5.92	6.08	8.67	6.30
Vanadium, wt% (±1.0)	0.14	0.12	0.11	0.10	0.11	0.12	0.12
Nickel, wt% (±1.0)	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	100.00	99.96	100.07	100.01	99.96	100.24	100.00
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.21	0.23	0.22	0.24	0.23	0.23	0.22
K, wt% (±0.5 ug/g)	0.22	0.24	0.24	0.26	0.24	0.23	0.24
Particulate size distribution							
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #28, wt%	0.05	0.04	0.04	0.03	0.04	0.00	0.04
Particulate Left Mesh, #48, wt%	0.05	0.04	0.04	0.03	0.04	0.00	0.04
Particulate Left Mesh, #100, wt%	1.25	3.57	2.88	1.45	0.17	0.31	1.86
Particulate Left Mesh, #270, wt%	23.45	24.02	24.85	25.55	26.05	21.38	24.78
Particulate Left Mesh, #325, wt%	14.22	11.76	13.45	14.33	15.38	26.10	13.83
Bottom, wt%	59.78	60.04	57.54	57.41	58.11	50.10	58.58

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY FLYASH ANALYSES

Flyash	Unit #2 Jan. 14, 2004						
Lab Number	31990-02 (Bag House)	31990-04 (Bag House)	31990-08 (Bag House)	31990-11 (Bag House)	31990-13 (Bag House)	31990-15 (Bag House)	Average Values
Time	10:06	11:35	12:23	13:46	14:20	15:15	
Unburned carbon, wt%	7.73	7.30	7.34	7.38	7.44	2.96	7.44
Compound analysis							
CaSO4, wt% (±0.2)	38.83	35.02	23.47	27.29	31.14	38.37	31.15
Sulfur, wt% (±0.09)	1.38	1.25	0.85	0.98	0.17	0.20	0.93
Ash compound analysis							
SiO2, wt% (±0.65)	0.30	0.23	0.13	0.15	0.16	0.29	0.19
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	61.65	61.59	61.80	62.46	62.64	52.16	62.03
CaO, wt% (±4.74) (Not Part of Norma	20.80	20.90	20.86	20.91	20.90	22.33	20.88
MgO, wt% (±1.25)	4.56	4.14	4.24	4.02	3.90	8.18	4.17
Na2O, wt% (±3.70)	6.19	6.32	6.27	5.95	5.98	12.28	6.14
K2O, wt% (±4.25)	6.35	6.77	6.61	6.48	6.38	4.91	6.52
Vanadium, wt% (±1.0)	0.13	0.12	0.12	0.12	0.11	0.14	0.12
Nickel, wt% (±1.0)	0.02	0.02	0.02	0.02	0.02	1.23	0.02
	100.00	100.10	100.06	100.11	100.10	101.53	100.07
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.17	0.17	0.17	0.18	0.18	0.17	0.17
K, wt% (±0.5 ug/g)	0.20	0.21	0.20	0.22	0.21	0.07	0.21
Particulate size distribution							
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #28, wt%	0.03	0.04	0.05	0.05	0.04	0.03	0.04
Particulate Left Mesh, #48, wt%	0.05	0.08	0.07	0.08	0.04	0.06	0.06
Particulate Left Mesh, #100, wt%	0.18	0.20	0.19	0.15	0.17	0.16	0.18
Particulate Left Mesh, #270, wt%	33.34	46.68	41.56	30.45	23.61	29.52	35.13
Particulate Left Mesh, #325, wt%	24.35	30.78	20.19	25.87	20.31	30.33	24.30
Bottom, wt%	40.75	22.18	36.64	42.10	55.54	38.60	39.44

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY FLYASH ANALYSES

Flyash	Unit #2 Jan. 14, 2004						
Lab Number	31990-01 (Air heater)	31990-03 (Air heater)	31990-06 (Air heater)	31990-09 (Air heater)	31990-12 (Air heater)	32065-02B (Isokinetic)	Average Values
Time	10:00	11:05	12:03	13:06	14:00		
Unburned carbon, wt%	2.80	2.34	2.49	3.35	2.80	7.29	2.76
Compound analysis							
CaSO4, wt% (±0.2)	23.47	21.05	29.86	30.95	34.43	24.90	27.95
Sulfur, wt% (±0.09)	0.83	0.75	1.05	1.08	0.18	0.90	0.78
Ash compound analysis							
SiO2, wt% (±0.65)	0.20	0.17	0.30	0.25	0.33	0.15	0.25
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	68.80	69.29	69.12	68.08	69.17	58.73	68.89
CaO, wt% (±4.74) (Not Part of Norma	22.50	22.57	22.56	22.36	22.60	21.16	22.52
MgO, wt% (±1.25)	5.76	5.88	5.84	5.50	5.78	4.05	5.75
Na2O, wt% (±3.70)	2.48	2.19	2.21	3.01	2.20	7.87	2.42
K2O, wt% (±4.25)	1.63	1.37	1.45	2.06	1.45	8.25	1.59
Vanadium, wt% (±1.0)	0.30	0.27	0.26	0.26	0.24	0.12	0.27
Nickel, wt% (±1.0)	0.04	0.03	0.03	0.03	0.03	0.02	0.03
	101.70	101.77	101.76	101.56	101.80	100.35	101.71
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.06	0.05	0.05	0.07	0.05	0.18	0.05
K, wt% (±0.5 ug/g)	0.04	0.03	0.04	0.05	0.04	0.21	0.04
Particulate size distribution							
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.04	0.08	0.12	0.08	0.10	0.00	0.08
Particulate Left Mesh, #28, wt%	0.12	0.10	0.08	0.12	0.10	0.00	0.10
Particulate Left Mesh, #48, wt%	0.16	0.14	0.12	0.16	0.14	0.00	0.14
Particulate Left Mesh, #100, wt%	0.56	0.55	0.53	0.29	0.41	0.00	0.47
Particulate Left Mesh, #270, wt%	68.96	69.63	70.30	59.58	64.94	26.77	66.68
Particulate Left Mesh, #325, wt%	8.95	8.46	7.96	10.30	9.13	25.81	8.96
Bottom, wt%	21.13	20.97	20.81	29.30	25.06	41.61	23.45

ATTACHMENT K

Ambient Data, Jan. 13, 2004 & Jan. 14, 2004

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY MET DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Characteristic Being Measured	**Values Used in Efficiency Calculation**	
Dry Bulb Temperature, North / South, deg F	61.0	62.78
Count	478	482
Standard Deviation	2.9707	4.8577
Wet Bulb Temperature, North / South, deg F	49.6	51.26
Count	478	482
Standard Deviation	1.7038	1.8616
Atmospheric Pressure, in Hg	30.43	30.24
Atmospheric Pressure, psia	14.9	14.8
Count	5	5
Standard Deviation	0.01207	0.02918

ATTACHMENT L

Ambient Data, Jan. 15, 2004 & Jan. 16, 2004

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY MET DATA - PARTIAL LOADS

DATE	WET BULB, DEG F	DRY BULB, DEG F	PRESSURE, PSIA	RELATIVE HUMIDITY, %
JAN. 16, 2004	48	54	14.696	64.77
40% LOAD	47	53	14.696	64.12
	45	50	14.696	68.08
	44	50	14.696	62.03
	43	49	14.696	61.28
JAN. 16, 2004	54	60	14.696	68.21
60% LOAD	54	61	14.696	63.84
	53	59	14.696	67.68
	52	57	14.696	71.89
	52	57	14.696	71.89
JAN. 15, 2004	55	61	14.696	68.71
80% LOAD	56	62	14.696	69.20
	54	63	14.696	55.80
	54	62	14.696	59.71
	54	62	14.696	59.71

ATTACHMENT M

Ontario Hydro Mercury Emission Summary

Black & Veatch
Clean Air Project No. 9475-1
100% Pittsburgh No. 8 Coal

Ontario Hydro Mercury Emission Summary

JEA Northside Generating Station - Unit 2

Run No.	Particulate Bound Hg^{tp} (lb/hr)	Separate Oxidized Hg^{2+} (lb/hr)	Separate Elemental Hg^{0} (lb/hr)	Total Mercury Hg^{Total} (lb/hr)
SDA Inlet Run 1	0.033263	0.000361	0.008258	0.041882
SDA Inlet Run 2	0.023739	0.001389	0.005065	0.030193
SDA Inlet Run 3	0.035793	0.000295	0.008621	0.044709
Average	**0.030932**	**0.000682**	**0.007315**	**0.038928**
Stack Run 1	0.000021	0.000021	0.005545	0.005566
Stack Run 2	0.000021	0.000021	0.007509	0.007530
Stack Run 3	0.000021	0.000063	0.005125	0.005146
Average	**0.000021**	**0.000035**	**0.006060**	**0.006081**
Removal Efficiency (%)	**99.93%**	**94.87%**	**17.16%**	**84.38%**

Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters
Total Mercury (Hg^{Total}) Results

Run No.		1	2	3		Average
Date (2004)		Jan 13	Jan 13	Jan 13		
Start Time (approx.)		11:19	15:50	18:40		
Stop Time (approx.)		14:44	18:08	20:47		
Process Conditions						
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780		
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800		
Cap	Capacity factor (hours/year)	8,760	8,760	8,760		
Gas Conditions						
O_2	Oxygen (dry volume %)	4.8000	4.6000	4.8000		**4.7333**
CO_2	Carbon dioxide (dry volume %)	14.1000	14.3000	14.1000		**14.1667**
T_s	Sample temperature (°F)	317.6250	319.2500	317.5417		**318.1389**
B_w	Actual water vapor in gas (% by volume)	8.3739	7.9066	7.4743		**7.9183**
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	976,004	971,461	988,368		**978,611**
Q_s	Volumetric flow rate, standard (scfm)	630,041	625,639	637,925		**631,202**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	577,282	576,172	590,245		**581,233**
Q_a	Volumetric flow rate, actual (acf/hr)	58,560,246	58,287,688	59,302,059		**58,716,664**
Q_s	Volumetric flow rate, standard (scf/hr)	37,802,449	37,538,334	38,275,518		**37,872,100**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	34,636,927	34,570,337	35,414,675		**34,873,980**
Q_a	Volumetric flow rate, actual (m^3/hr)	1,658,461	1,650,742	1,679,469		**1,662,891**
Q_s	Volumetric flow rate, standard (m^3/hr)	1,070,588	1,063,108	1,083,985		**1,072,560**
Q_{std}	Volumetric flow rate, dry standard (dry m^3/hr)	980,938	979,052	1,002,964		**987,652**
Q_s	Volumetric flow rate, normal (Nm^3/hr)	997,593	990,623	1,010,077		**999,431**
Q_{std}	Volumetric flow rate, dry normal (Nm^3/hr)	914,056	912,299	934,581		**920,312**
Sampling Data						
V_{mstd}	Volume metered, standard (dscf)	82.4059	85.6378	84.7806		**84.2748**
%I	Isokinetic sampling (%)	100.5579	104.7030	101.1837		**102.1482**
Laboratory Data						
$Hg_{particle}$	Total Particulate Bound Mercury (µg)	35.8900	26.6700	38.8600		**33.8067**
Hg_O	Total Oxidized Mercury (µg)	0.3900	1.5600	0.3200		**0.7567**
Hg_E	Total Elemental Mercury (µg)	8.9100	5.6900	9.3600		**7.9867**
m_n	Total Mercury (µg)	45.1900	33.9200	48.5400		**42.5500**
Total Mercury Results						
C_{sd}	Concentration (lb/dscf)	1.2092E-09	8.7337E-10	1.2624E-09		**1.1150E-09**
C_a	Concentration (lb/acf)	7.1520E-10	5.1800E-10	7.5392E-10		**6.6237E-10**
C_{sd}	Concentration (µg/dscm)	1.9363E+01	1.3986E+01	2.0216E+01		**1.7855E+01**
C_{sd}	Concentration (mg/dscm)	1.9363E-02	1.3986E-02	2.0216E-02		**1.7855E-02**
C_a	Concentration (µg/m^3 (actual,wet))	1.1453E+01	8.2950E+00	1.2073E+01		**1.0607E+01**
C_{sd}	Concentration (µg/Nm^3 dry)	2.0780E+01	1.5009E+01	2.1696E+01		**1.9162E+01**
$E_{lb/hr}$	Rate (lb/hr)	4.1882E-02	3.0193E-02	4.4709E-02		**3.8928E-02**
$E_{g/s}$	Rate (g/s)	5.2762E-03	3.8036E-03	5.6323E-03		**4.9040E-03**
$E_{T/yr}$	Rate (Ton/yr)	1.8345E-01	1.3224E-01	1.9583E-01		**1.7050E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.5352E-05	1.0952E-05	1.6028E-05		**1.4110E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.5436E-05	1.0993E-05	1.6116E-05		**1.4182E-05**

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Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Particulate Bound (Hg^{tp}) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	9.6034E-10	6.8670E-10	1.0107E-09	**8.8591E-10**
C_a	Concentration (lb/acf)	5.6802E-10	4.0728E-10	6.0357E-10	**5.2629E-10**
C_{sd}	Concentration (µg/dscm)	1.5378E+01	1.0997E+01	1.6185E+01	**1.4187E+01**
C_{sd}	Concentration (mg/dscm)	1.5378E-02	1.0997E-02	1.6185E-02	**1.4187E-02**
C_a	Concentration (µg/m^3 (actual,wet))	9.0960E+00	6.5220E+00	9.6653E+00	**8.4278E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	1.6504E+01	1.1801E+01	1.7369E+01	**1.5225E+01**
$E_{lb/hr}$	Rate (lb/hr)	3.3263E-02	2.3739E-02	3.5793E-02	**3.0932E-02**
$E_{g/s}$	Rate (g/s)	4.1904E-03	2.9906E-03	4.5091E-03	**3.8967E-03**
$E_{T/yr}$	Rate (Ton/yr)	1.4569E-01	1.0398E-01	1.5677E-01	**1.3548E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.2192E-05	8.6112E-06	1.2831E-05	**1.1212E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.2260E-05	8.6438E-06	1.2902E-05	**1.1269E-05**

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Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Oxidized (Hg^{2+}) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.0436E-11	4.0167E-11	8.3227E-12	**1.9642E-11**
C_a	Concentration (lb/acf)	6.1724E-12	2.3823E-11	4.9702E-12	**1.1655E-11**
C_{sd}	Concentration (µg/dscm)	1.6711E-01	6.4322E-01	1.3328E-01	**3.1453E-01**
C_{sd}	Concentration (mg/dscm)	1.6711E-04	6.4322E-04	1.3328E-04	**3.1453E-04**
C_a	Concentration (µg/m^3 (actual,wet))	9.8842E-02	3.8149E-01	7.9591E-02	**1.8664E-01**
C_{sd}	Concentration (µg/Nm^3 dry)	1.7934E-01	6.9028E-01	1.4303E-01	**3.3755E-01**
$E_{lb/hr}$	Rate (lb/hr)	3.6146E-04	1.3886E-03	2.9474E-04	**6.8159E-04**
$E_{g/s}$	Rate (g/s)	4.5535E-05	1.7493E-04	3.7131E-05	**8.5865E-05**
$E_{T/yr}$	Rate (Ton/yr)	1.5832E-03	6.0820E-03	1.2910E-03	**2.9854E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.3249E-07	5.0369E-07	1.0566E-07	**2.4728E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.3322E-07	5.0560E-07	1.0625E-07	**2.4835E-07**

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Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Elemental (Hg^0) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Elemental Mercury Results					
C_{sd}	Concentration (lb/dscf)	2.3841E-10	1.4651E-10	2.4344E-10	**2.0945E-10**
C_a	Concentration (lb/acf)	1.4101E-10	8.6892E-11	1.4538E-10	**1.2443E-10**
C_{sd}	Concentration (µg/dscm)	3.8178E+00	2.3461E+00	3.8983E+00	**3.3541E+00**
C_{sd}	Concentration (mg/dscm)	3.8178E-03	2.3461E-03	3.8983E-03	**3.3541E-03**
C_a	Concentration (µg/m^3 (actual,wet))	2.2582E+00	1.3915E+00	2.3280E+00	**1.9926E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	4.0972E+00	2.5178E+00	4.1836E+00	**3.5995E+00**
$E_{lb/hr}$	Rate (lb/hr)	8.2579E-03	5.0648E-03	8.6213E-03	**7.3146E-03**
$E_{g/s}$	Rate (g/s)	1.0403E-03	6.3804E-04	1.0861E-03	**9.2147E-04**
$E_{T/yr}$	Rate (Ton/yr)	3.6169E-02	2.2184E-02	3.7761E-02	**3.2038E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	3.0268E-06	1.8372E-06	3.0906E-06	**2.6515E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	3.0436E-06	1.8441E-06	3.1077E-06	**2.6651E-06**

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Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters
Total Mercury (Hg^{Total}) Results

Run No.		1	2	3		Average
Date (2004)		Jan 13	Jan 13	Jan 13		
Start Time (approx.)		11:19	15:50	18:40		
Stop Time (approx.)		14:42	18:00	20:45		
Process Conditions						
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780		
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800		
Cap	Capacity factor (hours/year)	8,760	8,760	8,760		
Gas Conditions						
O_2	Oxygen (dry volume %)	5.2000	5.4000	5.8000		**5.4667**
CO_2	Carbon dioxide (dry volume %)	13.4000	13.5000	13.2000		**13.3667**
T_s	Sample temperature (°F)	240.7083	250.2083	234.0000		**241.6389**
B_w	Actual water vapor in gas (% by volume)	10.5308	10.6940	9.9813		**10.4020**
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	907,511	913,697	899,844		**907,017**
Q_s	Volumetric flow rate, standard (scfm)	685,928	681,365	686,707		**684,667**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	613,694	608,500	618,165		**613,453**
Q_a	Volumetric flow rate, actual (acf/hr)	54,450,670	54,821,797	53,990,630		**54,421,032**
Q_s	Volumetric flow rate, standard (scf/hr)	41,155,683	40,881,928	41,202,426		**41,080,012**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	36,821,650	36,510,025	37,089,874		**36,807,183**
Q_a	Volumetric flow rate, actual (m^3/hr)	1,542,075	1,552,586	1,529,046		**1,541,236**
Q_s	Volumetric flow rate, standard (m^3/hr)	1,165,553	1,157,800	1,166,877		**1,163,410**
Q_{std}	Volumetric flow rate, dry standard (dry m^3/hr)	1,042,811	1,033,985	1,050,407		**1,042,401**
Q_s	Volumetric flow rate, normal (Nm^3/hr)	1,086,084	1,078,859	1,087,317		**1,084,087**
Q_{std}	Volumetric flow rate, dry normal (Nm^3/hr)	971,710	963,486	978,788		**971,328**
Sampling Data						
V_{mstd}	Volume metered, standard (dscf)	77.4613	77.8307	77.5580		**77.6167**
%I	Isokinetic sampling (%)	99.6342	100.9638	99.0372		**99.8784**
Laboratory Data						
$Hg_{particle}$	Total Particulate Bound Mercury (µg)	0.0200	0.0200	0.0200		**0.0200**
Hg_O	Total Oxidized Mercury (µg)	<0.0200	<0.0200	<0.0600		**<0.0333**
Hg_E	Total Elemental Mercury (µg)	5.2900	7.2600	4.8600		**5.8033**
m_n	Total Mercury (µg)	5.3100	7.2800	4.8800		**5.8233**
Total Mercury Results						
C_{sd}	Concentration (lb/dscf)	1.5115E-10	2.0625E-10	1.3874E-10		**1.6538E-10**
C_a	Concentration (lb/acf)	1.0222E-10	1.3736E-10	9.5310E-11		**1.1163E-10**
C_{sd}	Concentration (µg/dscm)	2.4205E+00	3.3028E+00	2.2217E+00		**2.6483E+00**
C_{sd}	Concentration (mg/dscm)	2.4205E-03	3.3028E-03	2.2217E-03		**2.6483E-03**
C_a	Concentration (µg/m^3 (actual,wet))	1.6368E+00	2.1996E+00	1.5263E+00		**1.7876E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	2.5976E+00	3.5444E+00	2.3843E+00		**2.8421E+00**
$E_{lb/hr}$	Rate (lb/hr)	5.5657E-03	7.5301E-03	5.1458E-03		**6.0806E-03**
$E_{g/s}$	Rate (g/s)	7.0115E-04	9.4862E-04	6.4826E-04		**7.6601E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.4378E-02	3.2982E-02	2.2539E-02		**2.6633E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.9679E-06	2.7198E-06	1.8781E-06		**2.1886E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.0304E-06	2.7500E-06	1.8919E-06		**2.2241E-06**

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Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Particulate Bound (Hg^{tp}) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	5.6932E-13	5.6661E-13	5.6861E-13	**5.6818E-13**
C_a	Concentration (lb/acf)	3.8499E-13	3.7735E-13	3.9061E-13	**3.8432E-13**
C_{sd}	Concentration (µg/dscm)	9.1168E-03	9.0735E-03	9.1054E-03	**9.0986E-03**
C_{sd}	Concentration (mg/dscm)	9.1168E-06	9.0735E-06	9.1054E-06	**9.0986E-06**
C_a	Concentration (µg/m^3 (actual,wet))	6.1651E-03	6.0428E-03	6.2552E-03	**6.1544E-03**
C_{sd}	Concentration (µg/Nm^3 dry)	9.7839E-03	9.7375E-03	9.7717E-03	**9.7643E-03**
$E_{lb/hr}$	Rate (lb/hr)	2.0963E-05	2.0687E-05	2.1090E-05	**2.0913E-05**
$E_{g/s}$	Rate (g/s)	2.6409E-06	2.6061E-06	2.6568E-06	**2.6346E-06**
$E_{T/yr}$	Rate (Ton/yr)	9.1819E-05	9.0610E-05	9.2372E-05	**9.1600E-05**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.4121E-09	7.4721E-09	7.6970E-09	**7.5270E-09**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.6475E-09	7.5549E-09	7.7537E-09	**7.6520E-09**

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Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Oxidized (Hg^{2+}) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	<5.6932E-13	<5.6661E-13	<1.7058E-12	**<9.4725E-13**
C_a	Concentration (lb/acf)	<3.8499E-13	<3.7735E-13	<1.1718E-12	**<6.4473E-13**
C_{sd}	Concentration (µg/dscm)	<9.1168E-03	<9.0735E-03	<2.7316E-02	**<1.5169E-02**
C_{sd}	Concentration (mg/dscm)	<9.1168E-06	<9.0735E-06	<2.7316E-05	**<1.5169E-05**
C_a	Concentration (µg/m^3 (actual,wet))	<6.1651E-03	<6.0428E-03	<1.8765E-02	**<1.0324E-02**
C_{sd}	Concentration (µg/Nm^3 dry)	<9.7839E-03	<9.7375E-03	<2.9315E-02	**<1.6279E-02**
$E_{lb/hr}$	Rate (lb/hr)	<2.0963E-05	<2.0687E-05	<6.3269E-05	**<3.4973E-05**
$E_{g/s}$	Rate (g/s)	<2.6409E-06	<2.6061E-06	<7.9703E-06	**<4.4058E-06**
$E_{T/yr}$	Rate (Ton/yr)	<9.1819E-05	<9.0610E-05	<2.7712E-04	**<1.5318E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.4121E-09	<7.4721E-09	<2.3091E-08	**<1.2658E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.6475E-09	<7.5549E-09	<2.3261E-08	**<1.2821E-08**

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Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Elemental (Hg^0) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Elemental Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.5058E-10	2.0568E-10	1.3817E-10	**1.6481E-10**
C_a	Concentration (lb/acf)	1.0183E-10	1.3698E-10	9.4919E-11	**1.1124E-10**
C_{sd}	Concentration (µg/dscm)	2.4114E+00	3.2937E+00	2.2126E+00	**2.6392E+00**
C_{sd}	Concentration (mg/dscm)	2.4114E-03	3.2937E-03	2.2126E-03	**2.6392E-03**
C_a	Concentration (µg/m^3 (actual,wet))	1.6307E+00	2.1935E+00	1.5200E+00	**1.7814E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	2.5878E+00	3.5347E+00	2.3745E+00	**2.8324E+00**
$E_{lb/hr}$	Rate (lb/hr)	5.5448E-03	7.5094E-03	5.1248E-03	**6.0596E-03**
$E_{g/s}$	Rate (g/s)	6.9851E-04	9.4601E-04	6.4560E-04	**7.6337E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.4286E-02	3.2891E-02	2.2446E-02	**2.6541E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.9605E-06	2.7124E-06	1.8704E-06	**2.1811E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.0228E-06	2.7424E-06	1.8842E-06	**2.2164E-06**

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Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Mercury Laboratory Data - Data Entry Sheet

☐ DRAFT LAB DATA

Mercury	Units	Detection Limit	Blank (as-rcvd)	Run 1	Run 2	Run 3
Hg_{ash}-Filter Fraction	**µg**	0.0100		34.0000	24.9000	36.0000
Hg_{pr}-Probe Rinse Fraction	**µg**	0.0100		1.9100	1.7900	2.8800
Hg_{KCl}-KCl Fraction	**µg**	0.0200		0.5300	1.7000	0.4600
Hg_{H2O2}-HNO3-H2O2 Fraction	**µg**	0.0200		18.3000	15.5000	19.7000
Hg_{KMnO4}-KMnO4 Fraction	**µg**	0.0300		1.5300	1.1100	0.5800
V_{3a}-As-received Volume of KCl Blank	**ml**		300.0			
V_{5a}-As-received volume of HNO3-H2O2 Blank	**ml**		100.0			
V_{7a}-As-received volume of H2SO4-KMnO4 Blank	**ml**		300.0			
V_3-Volume of KCl charged to impingers	**ml**			300.0	300.0	300.0
V_5-Volume of HNO3-H2O2 charged to impingers	**ml**			100.0	100.0	100.0
V_7-Volume of H2SO4-KMnO4 charged to impingers	**ml**			300.0	300.0	300.0
Hg_{fb}-Filter Blank	**µg**		0.0200	0.0200	0.0200	0.0200
Hg_{Ob}-KCl Solution Blank	**µg**		0.1400	0.1400	0.1400	0.1400
Hg_{Eb1}-HNO3-H2O2 Blank	**µg**		**10.8000**	10.8000	10.8000	10.8000
Hg_{Eb2}-KMnO4 Blank	**µg**		0.1200	0.1200	0.1200	0.1200

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Notes:
"<" indicates result below reported minimum detection limit.

Solution blank values are derived by multiplying the as-received blank value by the ratio of the impinger charge volume to the as-received volume.

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SS OntHydro-1 Version 12-2003a

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Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Mercury Laboratory Data - Data Entry Sheet

☐ DRAFT LAB DATA

Mercury	Units	Detection Limit	Blank (as-rcvd)	Run 1	Run 2	Run 3
Hg_{ash}-Filter Fraction	**µg**	0.0100		0.0200	0.0200	0.0200
Hg_{pr}-Probe Rinse Fraction	**µg**	0.0100		<0.0100	<0.0100	<0.0100
Hg_{KCl}-KCl Fraction	**µg**	0.0200		0.0900	0.0800	<0.0600
Hg_{H2O2}-HNO3-H2O2 Fraction	**µg**	0.0200		17.9000	20.4000	17.9000
Hg_{KMnO4}-KMnO4 Fraction	**µg**	0.0300		0.7600	0.2300	0.3300
V_{3a}-As-received Volume of KCl Blank	**ml**		300.0			
V_{5a}-As-received volume of HNO3-H2O2 Blank	**ml**		100.0			
V_{7a}-As-received volume of H2SO4-KMnO4 Blank	**ml**		300.0			
V_3-Volume of KCl charged to impingers	**ml**			300.0	300.0	300.0
V_5-Volume of HNO3-H2O2 charged to impingers	**ml**			100.0	100.0	100.0
V_7-Volume of H2SO4-KMnO4 charged to impingers	**ml**			300.0	300.0	300.0
Hg_{fb}-Filter Blank	**µg**		<0.0100	<0.0100	<0.0100	<0.0100
Hg_{Ob}-KCl Solution Blank	**µg**		0.9800	0.9800	0.9800	0.9800
Hg_{Eb1}-HNO3-H2O2 Blank	**µg**		**13.2000**	13.2000	13.2000	13.2000
Hg_{Eb2}-KMnO4 Blank	**µg**		0.1700	0.1700	0.1700	0.1700

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O

Notes:
"<" indicates result below reported minimum detection limit.

Solution blank values are derived by multiplying the as-received blank value by the ratio of the impinger charge volume to the as-received volume.

Prepared by Clean Air Engineering Proprietary Software
SS OntHydro-1 Version 12-2003a

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FIGURES

FIGURE 1 - GENERAL ARRANGEMENT PLAN, DRAWING NO. 3847-1-100, REV. 3

FIGURE 2 - GENERAL ARRANGEMENT ELEVATION, DRAWING NO. 3847-1-101, REV. 3

FIGURE 3 - FABRIC FILTER EAST END ELEVATION, DRAWING NO. 3847-9-268, REV. 2

FIGURE 4 - GENERAL ARRANGEMENT UNIT 2 ISO VIEW (RIGHT SIDE), DRAWING NO. 43-7587-5-53

FIGURE 5 - GENERAL ARRANGEMENT UNIT 2 FRONT ELEVATION VIEW A-A, DRAWING NO. 43-7587-5-50, REV. C

FIGURE 6 - GENERAL ARRANGEMENT UNIT 2 SIDE ELEVATION, DRAWING NO. 43-7587-5-51, REV. C

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3847-1-100

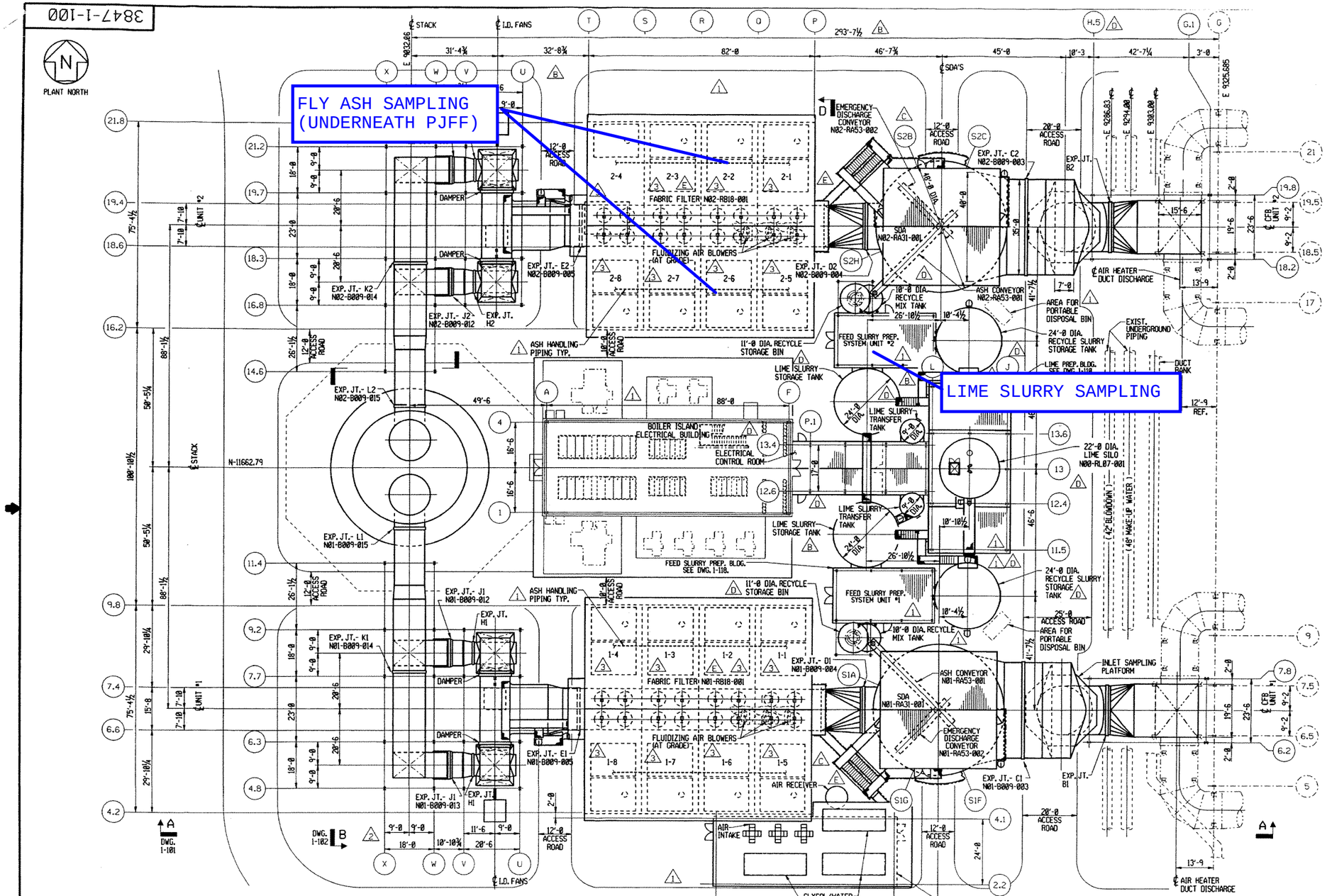

FIGURE 1

NOTES:

1. FOR COMPLETE COLUMN DESIGNATIONS & LOCATIONS SEE DWG. 9-001.
2. FOR TANK LOCATIONS SEE DWG. 9-003.

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NO.	REVISION	DWN.	CHK.	DATE
B	REVISED DIMENSIONS & LAYOUT ABS PREP AREA	RK	BN	8-28-99
C	MOVED STAIR TOWER	RK	BN	2-15-99
D	REV. TANK & COL. DESIGNATIONS	RWK		1-9-00
E	MOVED STAIR TOWER, REVISED EQUIP. NO'S.	RK	BN	2-4-00
R	DRAWING UPDATED AND CHECKED.	RK	DLM	3-1-00

NO.	REVISION	DWN.	CHK.	DATE
1	ADD ELECT BLDG & ASH HANDLING REF	CC		4-27-00
2	ADD OUT DUCT SUPT INFO, INC CUST COMMENT, ADD EXP JT TAGS	CC	BN	7-12-00
3	REV F.F. COMPARTMENT NUMBERING	CC		8-15-00

ISSUE RECORD

REV.	DATE	TO	FOR
2	7-14-00	WAPC & WATKINS	CONSTRUCTION
2	8-4-00	INSULATOR	BIOS
3	9-20-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
E	2-7-00	FOSTER WHEELER	INFORMATION
B	3-1-00	FABRICATOR	FAB INFO
B	4-3-00	FABRICATOR	BID INFO
I	4-28-00	FOSTER WHEELER	INFO
D	7-14-00	FOSTER WHEELER	INFO

REV.	DATE	TO	FOR
A	10-1-99	FOSTER WHEELER	INFORMATION
B	10-29-99	FOSTER WHEELER	INFORMATION
C	12-15-99	NELS	MODEL BID
D	1-11-00	NELS	MODEL FAB
D	1-14-00	FABRICATOR	BID INFO.

DRN. BY	RK	DATE	9-9-99
CHKD. BY	DLM	DATE	2-29-00
APPVD. BY	GG	DATE	3-1-00
SCALE	1/16"=1'-0		
CERTIFIED BY:		DATE:	

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

GENERAL ARRANGEMENT PLAN

Wheelabrator Air Pollution Control
A Waste Management Company

DRAWING NUMBER 3847-1-100 REV. NO. 3

B&V DWG. #62.0200.05-C0005
GEM CODE #N01-RA31-001, N02-RA31-001
N01-RB18-001 THRU 008, N02-RB18-001 THRU 008

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PLOT DATE: 15 SEP 2000 13:28:04
LAST PLOTTED BY: RK

P062713.62.0200.05-C0005 St:NE 11/21/00 MM-01186

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3847-1-101

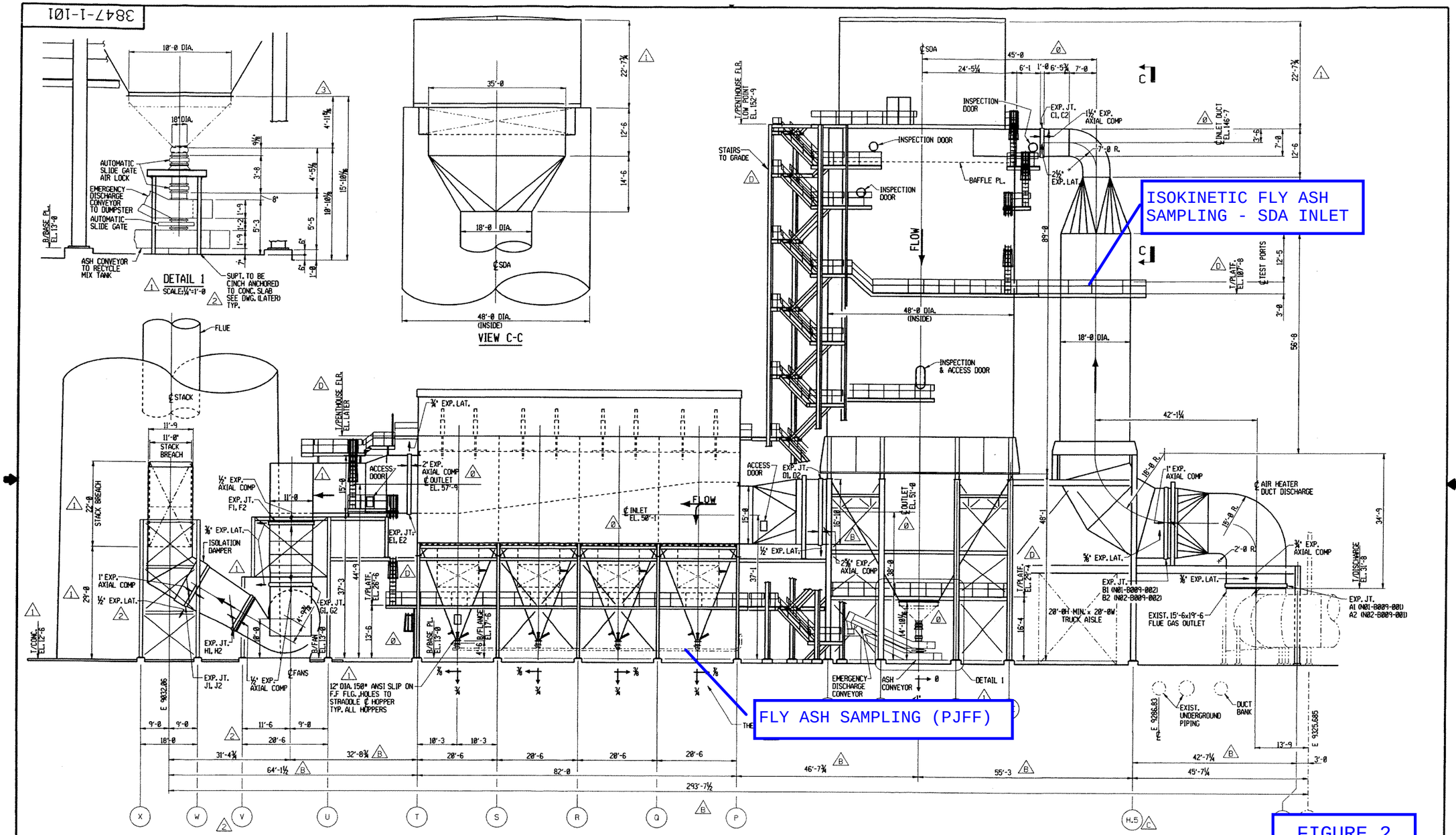

FIGURE 2

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B&V DWG. #62.0200.05-C0006
GEM CODE #N01-RA31-001, N02-RA31-001
N01-RB18-001 THRU 008, N02-RB18-001 THRU 008

NO.	REVISION	DRN.	CHK.	DATE
B	REVISED DIMENSIONS & TRUCK AISLE	BN	RK	8-26-99
C	REVISED COLUMN DESIGNATION	BN	RK	1-4-00
D	REVISED ACCESS ADDED ELEVATIONS	BN	RK	2-4-00
E	DWG UPDATED AND CHECKED	BN	RWK	3-1-00
F	REV DUCT DIM & ADD DETAIL 1	DM	CC	

NO.	REVISION	DRN.	CHK.	DATE
1	REVISED OUTLET DUCT & GENERAL REV.		RWK	4-27-00
2	ADD OUTLET DUCT SUPT INFO & INCORPORATE CUSTOMER COMMENT	BN	CC	7-12-00
3	ADD EXP MOVEMENTS AND EXP JT TAGS	BN	CC	7-19-00
3	REV. DIMENSIONS AT DETAIL 1			

ISSUE RECORD

REV.	DATE	TO	FOR
3	8-4-00	INSULATOR	BIDS
3	9-20-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
D	2-7-00	FOSTER WHEELER	INFORMATION
E	3-1-00	FABRICATOR	FAB INFO
1	4-28-00	FOSTER WHEELER	INFO
2	7-14-00	FOSTER WHEELER	INFO
2	7-14-00	WARC & WATKINS	CONSTRUCTION

REV.	DATE	TO	FOR
A	10-1-99	FOSTER WHEELER	INFORMATION
B	10-29-99	FOSTER WHEELER	INFORMATION
B	12-15-99	NELS	MODEL BID
B	1-11-00	NELS	MODEL FAB
C	1-14-00	FABRICATOR	BID INFO.

DRN. BY RK DATE 9-9-99
CHKD. BY DLM DATE 2-29-00
APPVD. BY GG DATE 3-1-00
SCALE 3/32"=1'-0
CERTIFIED
BY: DATE:

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

GENERAL ARRANGEMENT
ELEVATION

Wheelabrator Air Pollution Control
A Waste Management Company

DRAWING NUMBER 3847-1-101
REV. NO. 3

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PLOT DATE: 15 SEP 2000 13:28:26
LAST PLOTTED BY: RK

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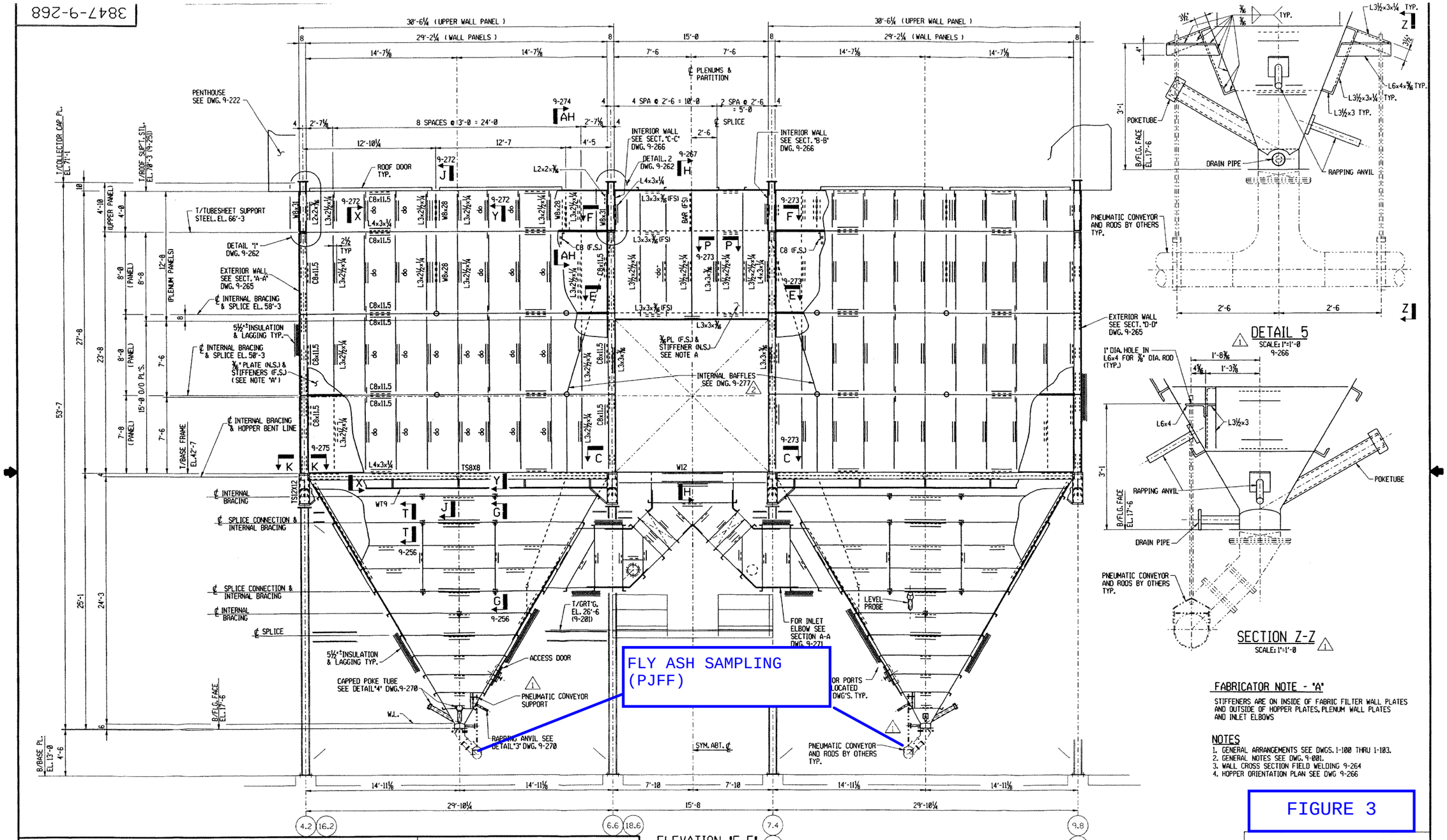

FLY ASH SAMPLING (PJFF)

ELEVATION "E-E"

(LOOKING WEST)
9-250 THRU 9-255

DETAIL 5

SCALE: 1"=1'-0
9-266

SECTION Z-Z

SCALE: 1"=1'-0

FABRICATOR NOTE - "A"

STIFFENERS ARE ON INSIDE OF FABRIC FILTER WALL PLATES AND OUTSIDE OF HOPPER PLATES, PLENUM WALL PLATES AND INLET ELBOWS

NOTES

1. GENERAL ARRANGEMENTS SEE DWGS. 1-100 THRU 1-103.
2. GENERAL NOTES SEE DWG. 9-001.
3. WALL CROSS SECTION FIELD WELDING 9-264
4. HOPPER ORIENTATION PLAN SEE DWG 9-266

FIGURE 3

GEM CODE *N01-RB18-001 THRU 008
N02-RB18-001 THRU 008

B&V DWG NO: 62.0200.05-C0064

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NO.	REVISION	DWN.	CHK.	DATE
0	DRAWING CHECKED	GL	WCC	2-24-00
1	ADD SUPTS FOR PNEUMATIC CONV., DET 5 & SECT Z-Z	CC	BW	5-22-00
2	REMOVED HOLD @ BAFFLE PL'S.	RK		8-15-00

NO.	REVISION	DWN.	CHK.	DATE

ISSUE RECORD

REV.	DATE	TO	FOR
2	9-13-00	WAPC & WATKINS	CONSTRUCTION
2	9-23-00	FOSTER WHEELER	INFORMATION

REV.	DATE	TO	FOR
A	1-14-00	FABRICATOR	BID
0	3-1-00	MCKAMISH	FAB
0	4-20-00	FOSTER WHEELER	INFO
1	5-22-00	MCKAMISH	INFO
1	8-4-00	INSULATOR	BID

DRN. BY	J.H.	DATE	12-16-99
CHKD. BY	W.C.C.	DATE	2-24-00
APPVD. BY	K.R.	DATE	3-1-00
SCALE	¼" = 1'-0		
CERTIFIED BY:		DATE:	

FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT

FABRIC FILTER
EAST END
ELEVATION E-E

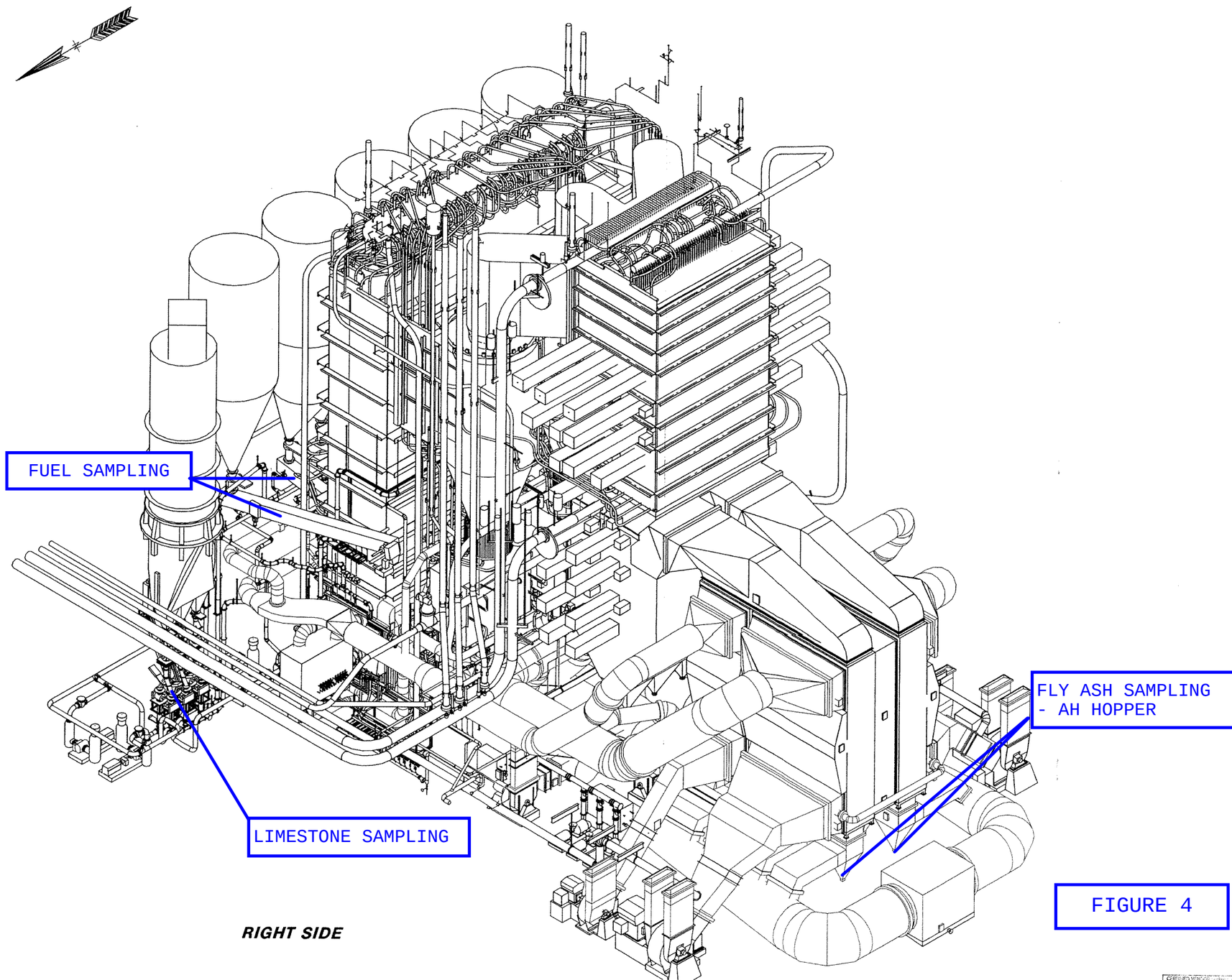
Wheelabrator Air Pollution Control
A Waste Management Company

DRAWING NUMBER 3847-9-268
REV. NO. 2

m:\contract\3847\cad\38479268.dgn

PLOT DATE: 15 SEP 2000 14:27:12
LAST PLOTTED BY: RK

DWG40998 03-MAR-2004 14:21:50



NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. FOR ADDITIONAL NOTES & REFERENCE DRAWINGS SEE DRAWING 43-7587-5-50

B&V Dwg No. 62.3401.05-C0012

REV	DATE	BY	DESCRIPTION
C	5-23-00	JHM	UPDATED DRAWING
B	5-26-99	JHM	DESIGN UPDATE
A	5-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
ISO VIEW (RIGHT SIDE)

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.
B&V Drawing No.: 62.3401.05-C0012

DRAWING NUMBER: 43-7587-5-53 | SCALE: | REVISION: C

DRAWN BY	JHM	3-16-99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

THIS DRAWING IS THE PROPERTY OF THE
FOSTER WHEELER ENERGY CORPORATION
PERRYVILLE, N.J.

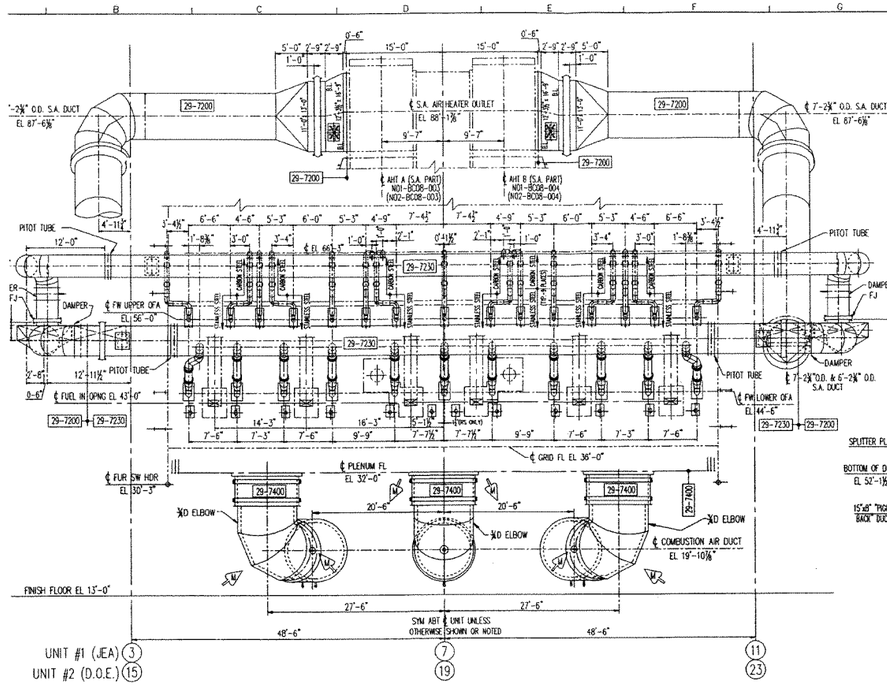
CERTIFIED VENDOR DRAWING
RELEASED FOR ERECTION
JUN 0 7 2000
FOSTER WHEELER ENERGY CORP.

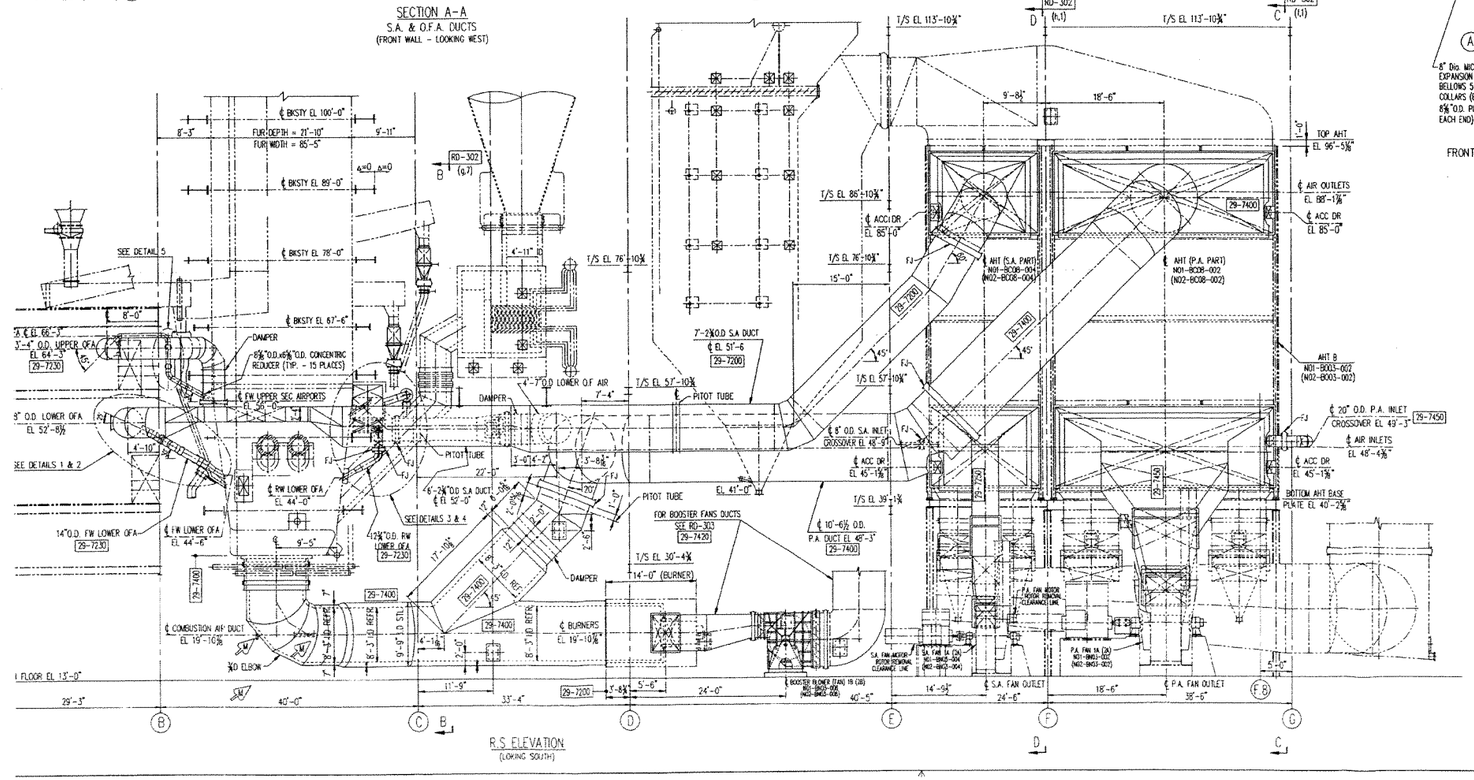
THIS IS A PDMS DRAWING.
REVISE ONLY IN PDMS

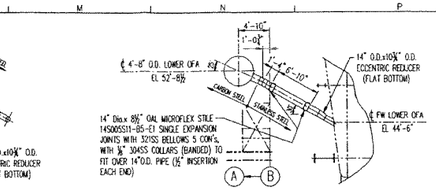
FIGURE 4

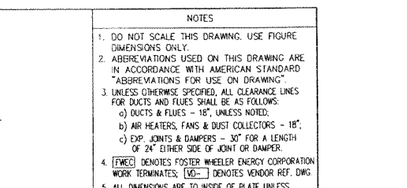
P062713.62.3401.05-C0012 St:NE 08/04/00 MM-00739

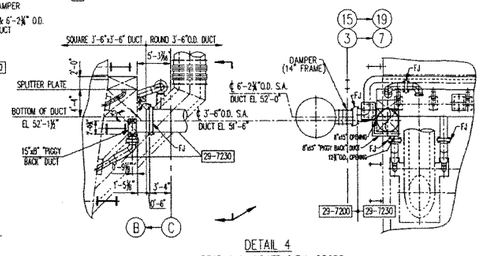
DWG40998 03-MAR-2004 14:30:51

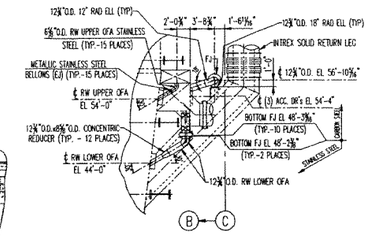


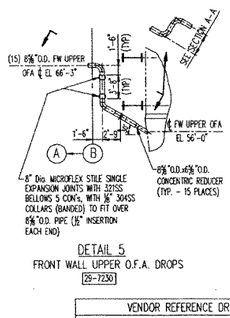












NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. UNLESS OTHERWISE SPECIFIED, ALL CLEARANCE LINES FOR DUCTS AND FLUES SHALL BE AS FOLLOWS:
   a) DUCTS & FLUES - 18", UNLESS NOTED.
   b) AIR HEATERS, FANS & DUST COLLECTORS - 18".
   c) EXP. JOINTS & DAMPERS - 30" FOR A LENGTH OF 24" EITHER SIDE OF JOINT OR DAMPER.
4. FWEC DENOTES FOSTER WHEELER ENERGY CORPORATION WORK TERMINATES; VO- DENOTES VENDOR REF. DWG.
5. ALL DIMENSIONS ARE TO INSIDE OF PLATE UNLESS OTHERWISE NOTED.
6. ALL ROUND MITERED DUCT ELBOWS RADIUS EQUAL ONE DIAMETR OF DUCT OR FLUE (R=1D) UNLESS OTHERWISE NOTED.
7. FOR PLATE THICKNESS, PLATE MATERIAL & EXPANSION JOINT INFORMATION REFER TO FLUE & DUCT ASSEMBLY DRAWINGS BEGINNING WITH DRAWING 43-7587-5-310, WHEN ISSUED.
8. ALL ACCESS DOORS ARE 18"x24"(H).

FWEC REFERENCE DRAWINGS

1. GENERAL ARRANGEMENT CROSS SECTION	43-7587-5-20
2. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS A-A & B-B	43-7587-5-21
3. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS C-C & D-D	43-7587-5-22
4. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS PLAN VIEW	43-7587-5-301
5. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS SECTIONS B-B, C-C, D-D AND VIEWS	43-7587-5-302
6. ARRANGEMENT AUXILLIARY EQUIPMENT BURNER BOOSTER BLOWERS (FANS) LAYOUT. PLAN VIEW & SECTIONS	43-7587-5-303
7. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEW @ AHT TOP, R.S. ELEVATION AND VIEWS A-A & B-B	43-7587-5-304
8. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEWS C-C & @ AHT SUPPORT LEVEL AND DETAILS	43-7587-5-305
9. INSTRUMENT LOCATION PLANS	43-7587-5-6400 THRU 6404, 6406, 6408, 6411, 6413 THRU 6419

VENDOR REFERENCE DRAWINGS

1. KENTUBE ENGINEERED PRODUCTS L.L.C.
   TUBULAR AIR HEATER - WP # AH001
   - GENERAL ARRANGEMENT 99091-1
   - AHT SUPPORT LAYOUT & LOAD DIAGRAM 99091-2
2. PEABODY ENGINEERING START-UP DUCT BURNER - WP # BRN01
   - GENERAL ARRANGEMENT D-326001
   - COMBUSTION AIR INLET & DUCT BURNER OUTLET FLANGE DETAILS C-326004
   BURNER PIPE RACK - WP # BRN01
   - HEADER PIPE RACK GENERAL ARRANGEMENT D-LATER
   - LOCAL PIPE RACK GENERAL ARRANGEMENT D-326036
3. CHICAGO BLOWER CORPORATION START-UP BURNER BOOSTER FAN - WP # BRN01
   - GENERAL ARRANGEMENT (CW) FAN "C" 19-0-2492-01
   - GENERAL ARRANGEMENT (CCW) FAN "A" 19-0-2492-02
   - GENERAL ARRANGEMENT (CW) FAN "B" 19-0-2493
4. ABBI GARDEN CITY FAN
   SECONDARY AIR FAN - WP # FAN01
   - GENERAL ARRANGEMENT (CCW) 43092
   - GENERAL ARRANGEMENT (CW) 43093
5. ABBI GARDEN CITY FAN
   PRIMARY AIR FAN - WP # FAN01
   - GENERAL ARRANGEMENT (CCW) 43104
   - GENERAL ARRANGEMENT (CW) 43105
6. TECO-WESTINGHOUSE MOTOR COMPANY
   PRIMARY AIR FAN MOTOR - WP # MTR01
   - GENERAL ARRANGEMENT (CCW) C2534AA
   - GENERAL ARRANGEMENT (CW) C2534AB
7. TECO-WESTINGHOUSE MOTOR COMPANY
   SECONDARY AIR FAN MOTOR - WP # MTR01
   - GENERAL ARRANGEMENT C8550AA
8. LUBE-POWER, INC.
   P. A. FAN & MOTOR LUBRICATION SYSTEM SKID - WP # FAN01
   - GENERAL ASSEMBLY LP1354-A

MCH	DATE	BY	DESCRIPTION
M	03-26-01	AGS	REVISED LOCATION OF RIGHT AND LEFT SIGHT GLASS PORTS AT COMBUSTION AIR DUCTS @ SECTION A-A AND RIGHT SIDE ELEVATION.
L	02-28-01	AGS	DELETED "HOLD" FROM COMBUSTION AIR DUCT AND ADDED (2) ACCESS DOOR AND DIMENSIONS TO IT AS SHOWN AT RIGHT SIDE ELEVATION.
K	01-12-00	AGS	ADDED VENDOR REFERENCE DRAWINGS VRD-8.
J	06-22-00	AGS	REVISED TAG NUMBER FOR BURNER BOOSTER FAN "B", S.A. & P.A. FANS @ R.S. ELEVATION. ADDED FWEC REFERENCE DRAWINGS RD-9. REVISED VENDOR REFERENCE DRAWINGS VRD-3. ADDED VENDOR REFERENCE DRAWINGS. PEABODY BURNER PIPE RACKS DRAWINGS. UPDATED BOOSTER BLOWER INLET & OUTLET DUCTING AND BOOSTER BLOWERS PICTURES ACCORDING TO ACTUAL PURCHASED FANS. PURCHASED FANS @ R.S. ELEVATION. REVISED DIMENSION 26'-0" (WAS 24'-0") FOR BOOSTER BLOWER "B" FROM ℄ TO COLUMN "D" @ R.S. ELEVATION.
H	03-08-00	AGS	REVISED SOME (8 of 13) FRONT WALL UPPER O.F.A. DROPS (29-7230) O.D. PIPE AT R.S. ELEVATION, SECTION A-A & DETAIL 5.
G	02-08-00	AGS	CORRECTED FWOSA (AG) Rev.1 FOR Pnl. 8 Sec. AHT PARTS.
F	02-04-00	AGS	ADDED P.A. FAN MOTOR VENDOR REFERENCE DRAWINGS. REVISED START-UP BURNER BOOSTER FAN VENDOR REFERENCE DRAWING NUMBERS. DELETED "HOLD" @ P.A. & S.A. FAN MOTORS & REVISED P.A. & S.A. FAN MOTORS PICTURES AT RIGHT SIDE ELEVATION. ADDED PART No.'S FOR DUCTS.
E	11-24-99	AGS	ADDED NOTE 8. REVISED DIMENSION BETWEEN COLUMNS "1.5" & "C": 5'-0" (WAS 6'-0") @ R.S. ELEVATION. ADDED P.A. FAN VENDOR REFERENCE DRAWING NUMBERS. REVISED P.A. FAN PICTURE TO INCLUDE ACTUAL PURCHASED FAN @ R.S. ELEVATION. ADDED DETAIL 5. REVISED SIZE OF FW UPPER OFA DROPS (EXPANSION JOINT). TOOK SECTION WITH (7) TWO METALLIC BELLOWS (WAS (1) ONE FABRIC EJ) @ R.S. ELEVATION & SECTION A-A.
D	11-08-99	AGS	ADDED VENDOR REFERENCE DRAWINGS. ADDED FWEC REFERENCE DRAWINGS No.'S 5, 7 & 8. ADDED S.A. DUCTS TO INTREX SOLID RETURN LEG. ADDED P.A. & S.A. AHT INLET DUCT CROSSOVERS. REVISED SIZE OF FW LOWER OFA DROPS: 14"O.D. (WAS 16" O.D.). ADDED TRANSITIONS. SHEET 8. REVISED DIMENSIONS AND ADDED DETAILS INFO WHERE INDICATED ON SHEET 8.
C	06-25-99	AGS	REVISED @ STIFFENERS TO TRACK COMMENTS (ADDED GRADE INFO, NOTES, & BMC INFO). REVISED S.A. & P.A. DUCTS AS SHOWN.
B	6/7/98	AP	ADDED FDJ AND SEC. AIR FANS AND DUCTS TO AIR HEATER. ADDED PRIMARY AIR FLOW MEASUREMENT DEVICES AT SEC. AND QT. AIR DUCTS. REVISED QT. AIR DUCTS AT BOILER FRONT AND REAR WALLS. DRAWING ISSUED FOR START AND PERFORMANCE REVIEW.
A	5/10/98	AP	ISSUED FOR PRIMARY AND SECARD DUCT LOAD CALCULATIONS ONLY.

REVISIONS

FOSTER WHEELER ENERGY CORPORATION
STEAM GENERATOR
ARRANGEMENT OF AUXILIARY EQUIPMENT
SECONDARY & PRIMARY AIR DUCTS
R.S. ELEVATION, SECTION A-A AND DETAILS 1 THRU 4

JEA JACKSONVILLE, FLORIDA
NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.: N01-BN, N02-BN
B&V Drawing No.: 62.3401.05-C0046

DRAWING NUMBER: 43-7587-5-300
SCALE: 3/8" = 1'-0"
REVISION: M

DRAWN BY	AF	4/8/99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

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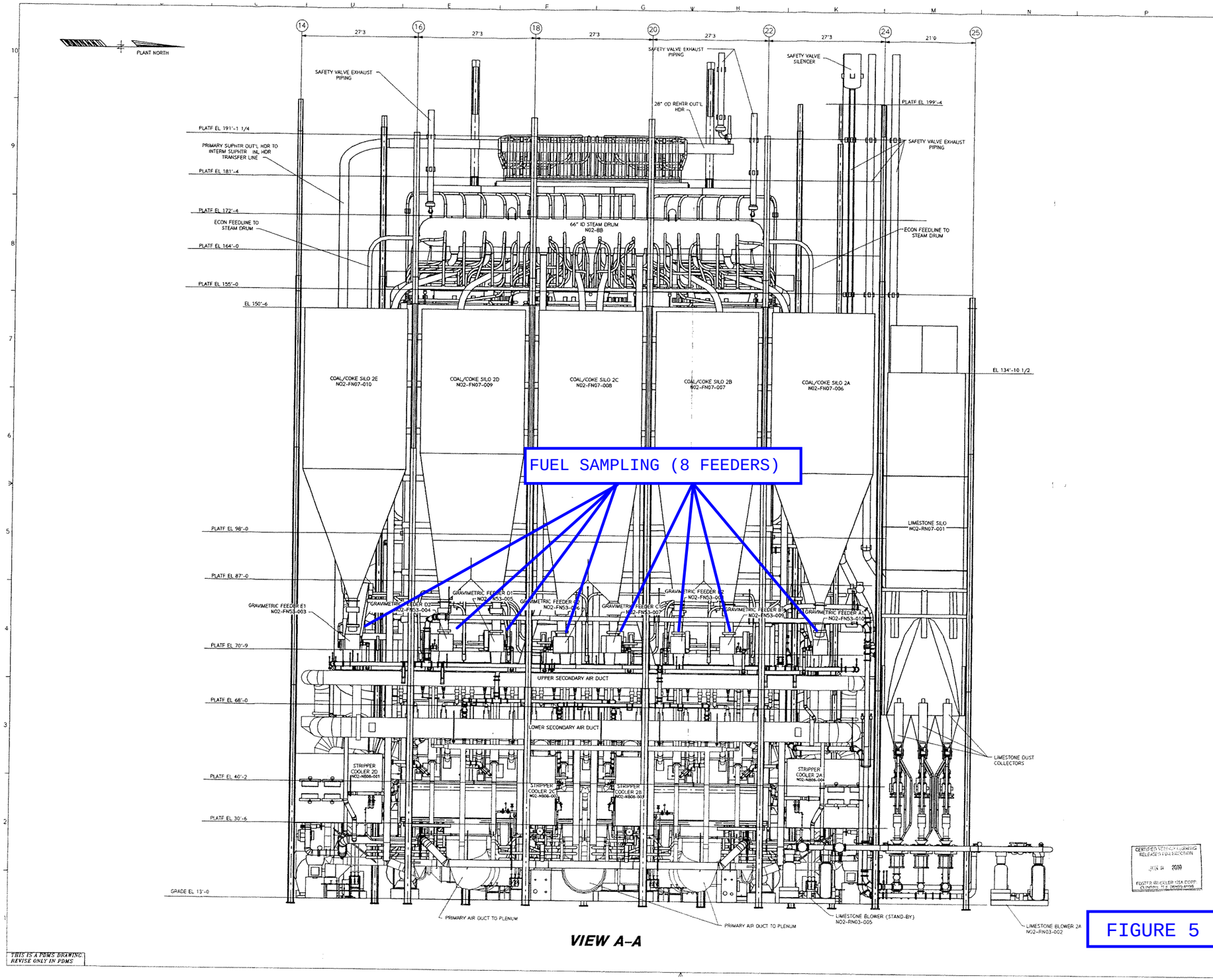
P062713.62.3401.05-C0046 St:RD 05/08/01 MM-01825

DWG40998 03-MAR-2004 14:30:16



NOTES

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REFERENCE DRAWINGS

GENERAL ARRANGEMENT CROSS SECTION	43-7587-5-20
GENERAL ARRANGEMENT LONGITUDINAL SECTIONS A-A & B-B	43-7587-5-21
GENERAL ARRANGEMENT LONGITUDINAL SECTIONS C-C & D-D	43-7587-5-22
PENTHOUSE RISERS & TRANSFER TUBES	43-7587-5-170
SECTIONS & DETAILS IN HRA	43-7587-5-160
CYCLONE SECTIONAL ARRANGEMENT	43-7587-5-200
INTERMEDIATE SUPERHEATER 1 ARRANGEMENT	43-7587-5-210
INTERMEDIATE SUPERHEATER 2 ARRANGEMENT	43-7587-5-211
INTERMEDIATE SUPERHEATER 3 ARRANGEMENT	43-7587-5-212
ARRANGEMENT OF AUXILIARY EQUIPMENT	43-7587-5-300
INTREX GENERAL ARRANGEMENT	43-7587-5-380
DOWNCOMER ARRANGEMENT AND DETAILS	43-7587-5-400
FURNACE FEEDER ARRANGEMENT	43-7587-5-405
TRANSFER LINES TO LOWER CYCLONE INLET HEADERS	43-7587-5-410
SAFETY VALVE EXHAUST PIPING ARRANGEMENT	43-7587-5-416
STRIPPER COOLER ARRANGEMENT	43-7587-5-430
ARRANGEMENT OF 66" ID DRUM	43-7587-5-480
KEY PLAN BOILER & AIR HEATER	43-7587-5-9001

B&V Dwg No: 62.3401.05-C0057

REV	DATE	BY	DESCRIPTION
C	5-16-00	JHM	UPDATED DRAWING AND ADDED EQUIPMENT DESIGNATIONS
B	5-26-99	JHM	DESIGN UPDATE
A	3-30-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
FRONT ELEVATION
VIEW A-A

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No:
B&V Drawing No.: 62.3401.05-C0057

DRAWING NUMBER: 43-7587-5-50
SCALE:
REVISION: C

DRAWN BY	WDJ	3-16-99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

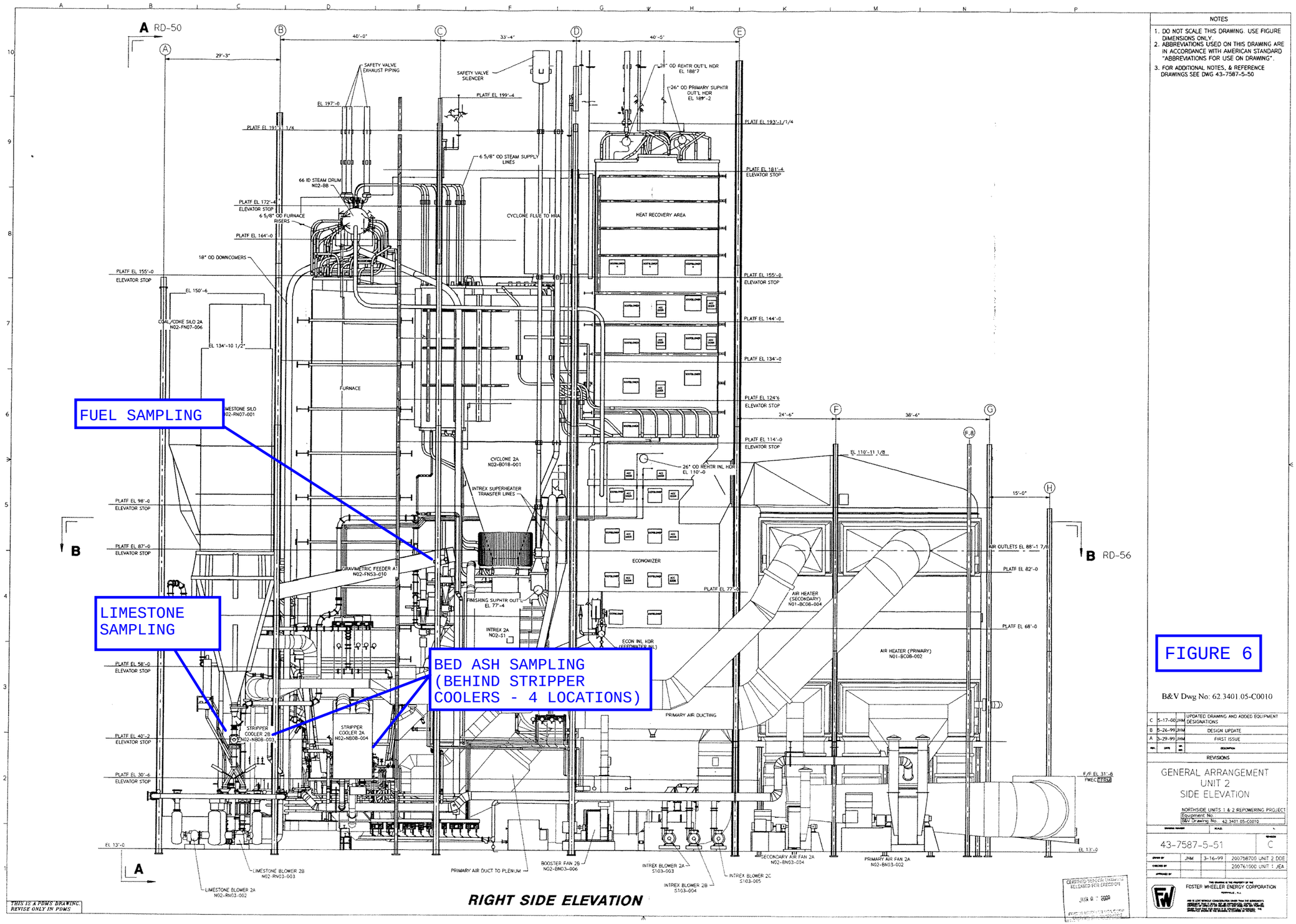
FOSTER WHEELER ENERGY CORPORATION

CERTIFIED NEW CONSTRUCTION RELEASED FOR EXECUTION JUN 14 2000 FOSTER WHEELER USA CORP. CLINTON, N.J. DENVER, COLO.

FIGURE 5

P062713.62.3401.05-C0057 St:NE 08/04/00 MM-00739

DWG40998 03-MAR-2004 14:18:59



NOTES

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3. FOR ADDITIONAL NOTES, & REFERENCE DRAWINGS SEE DWG 43-7587-5-50

FIGURE 6

B&V Dwg No: 62.3401.05-C0010

REV.	DATE	BY	DESCRIPTION
C	5-17-00	JHM	UPDATED DRAWING AND ADDED EQUIPMENT DESIGNATIONS
B	5-26-99	JHM	DESIGN UPDATE
A	3-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
SIDE ELEVATION

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No:
B&V Drawing No: 62.3401.05-C0010

43-7587-5-51 C

DRAWN BY JHM 3-16-99 200758700 UNIT 2 DOE
CHECKED BY 200761000 UNIT 1 JEA
APPROVED BY

FOSTER WHEELER ENERGY CORPORATION

CERTIFIED VENDOR DRAWING RELEASED FOR CONSTRUCTION JUN 8 - 2000

P062713.62.3401.05-C0010 St:NE 08/04/00 MM-00739

CATALYST

AIR MANAGEMENT, INC.

SCANNER/QC

AI#: 3004
ID#:
Graybar: CMN2005
Doc Title:

AIR QUALITY TESTING SERVICES

EAST KENTUCKY POWER COOPERATIVE, INC
SPURLOCK STATION
GILBERT UNIT 3

COMPLIANCE EMISSIONS TEST REPORT

Catalyst Air Management, Inc.
Report Number 158-052

SEPTEMBER 2, 2005
Test Date: June 8-13 and August 17-18, 2005

RECEIVED
SEP 29 2005
TECHNICAL SERVICES BRANCH
DIVISION FOR AIR QUALITY

2505 Byington-Solway Road
Knoxville, TN 37931
(865) 531-0075 • Fax (865) 531-0750

29541 Morningmist Drive
Tampa, FL 33543
(813) 994-5880 • Fax (813) 994-5571

10 Mill Road
Morgantown, PA 19543
(610) 913-7600 • Fax (610) 913-7608

EAST KENTUCKY POWER COOPERATIVE, INC.
SPURLOCK STATION
GILBERT UNIT 3

COMPLIANCE EMISSIONS TEST REPORT

CATALYST AIR MANAGEMENT, INC.
REPORT NUMBER 158-052

September 2, 2005
Test Dates: June 8-16 and August 17-18, 2005

RECEIVED
SEP 29 2005
TECHNICAL SERVICES BRANCH
DIVISION FOR AIR QUALITY

Prepared for
Mr. Louis Petrey
East Kentucky Power Cooperative, Inc.
J.K. Smith Power Station
12145 Irvine Road
Winchester, KY 40391

CATALYST

AIR MANAGEMENT, INC.

STATEMENT OF VALIDITY

RECEIVED
SEP 29 2005
TECHNICAL SERVICES BRANCH
DIVISION FOR AIR QUALITY

East Kentucky Power Cooperative – Gilbert Unit 3
Catalyst Report 158-052
September 2, 2005

To the extent practical, information and data provided in this test report has been verified as true and correct.

Michael J. Taylor
President

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PROJECT FACT SHEET

NAME OF SOURCE OWNER:	East Kentucky Power Cooperative, Inc.
SOURCE IDENTIFICATION:	Gilbert Unit 3 Permit V-97-050 Revision1 AFS Plant ID 21-161-00009
LOCATION OF SOURCE:	State Road 8 Maysville, KY
TYPE OF OPERATION:	Coal Fired CFB Steam Generating Unit Fly Ash and Bottom Ash Handling Limestone Handling
TYPES OF TESTS PERFORMED:	Sample Traverse-EPA Method 1 Volumetric Flow Rate-EPA Method 2 Oxygen/Carbon Dioxide-EPA Method 3A Moisture Content-EPA Method 4 Particulate-EPA Method 5 and 17 Sulfur Dioxide-EPA Method 6C Nitrogen Oxide-EPA Method 7E Sulfuric Acid Mist-EPA Method 8 Carbon Monoxide-EPA Method 10 VOC-EPA Method 25A HCL/HF-EPA Method 26A Trace Metals-EPA Method 29
SOURCE ANALYZERS:	Teledyne Ultraflow 150 - 1500184 Thermo Environmental NOx - 42C-0417006733 Thermo Environmental SO_2 - 43C-0417006736 Thermo Environmental CO_2 - 41C-0417006740 Thermo Environmental CO - 48C--417006736
TEST COMPANY:	Catalyst Air Management, Inc. 2505 Byington-Solway Road Knoxville, TN 37931
SITE SUPERVISOR:	Mike Taylor - Principal
TEST PERSONNEL:	Josh Nicely - Testing Supervisor Huedon Love - Technician Chris Heilner - Technician Brian Williams - Technician Keith Hale - Technician

PROJECT FACT SHEET

TEST DATES:	June 8-13 and August 17-18, 2005
OWNERS REPRESENTATIVE:	Doug Martin Louis Petrey Robert Webb Greg Williams
TEST OBSERVER:	Gerald Slucher - KY DEP John Jayne - KY DEP Carla – KY DEP

1.0 Introduction

Catalyst Air Management, Inc. (Catalyst) was contracted by East Kentucky Power Cooperative, Inc. to perform the initial compliance testing at Spurlock Station, Gilbert Unit 3.

The sampling program was conducted June 8 through 16 and August 17 and 18, 2005. The RATA was performed by Messers. Mike Taylor, Josh Nicely, Huedon Love, Chris Heilner, Brain Williams and Keith Hale of Catalyst, with the assistance of personnel assigned by East Kentucky Power Cooperative. Messers. Louis Petrey, Robert Webb and Greg Williams coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source sampling program are presented in Tables 1 through 8. The summary tables are presented as follows:

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1	Summary of Emissions	2
2	Summary of Particulate Emissions	2
3	Summary of Metals Emissions	3
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3.0 Results of Testing

The individual test run results are shown in Tables 4 through 12, and are tabulated in Appendices 1 and 2. The results indicate that all the regulate pollutants are in compliance with the permitted limits.

TABLE 1
Summary of Emissions
Gilbert Unit 3

Pollutant	Avgerage lb/mmBtu	Permit lb/mmBtu
NOx	0.09	0.10
SO_2	0.17	0.20
CO	0.06	0.15
VOC	0.001	0.004
Beryllium (Be)	.0000000095	0.0000146
Lead (Pb)	0.00000017	.0000063
Mercury (Hg)	0.000001	0.00000265
Acid Mist	0.004	0.005
HCl	0.000056	0.0035
HF	0.000056	0.00047
Particulate	0.005	0.015

TABLE 2
Summary of Particulate Emissions
Gilbert Unit 3

Concentration gr/dscf	Emission rate lb/mmBtu	Opacity %
0.002	0.005	2.0
0.036	0.068	16.8
0.012	0.023	8.6
0.007	0.014	6.4

TABLE 3
Summary of Metals Emissions
Gilbert Unit 3

Pollutant	Stack lb/MMBtu	Coal lb/MMBtu	Removal Efficiency (%)
Beryllium (Be)	9.5E-09	1.49E-04	99.99
Lead (Pb)	1.7E-06	5.81E-04	99.71
Mercury (Hg)	1.0E-06	9.76E-06	89.52

TABLE 4
Summary of HCl/HF Emissions
Gilbert 3

Pollutant	Stack lb/mmBtu	Coal Content	Coal lb/mmBtu
HCl	5.6E-03	0.031 %	0.026
HF	5.6E-03	119.5 ppm	99.6

TABLE 5
Summary of Acid Mist Emissions
Gilbert 3

Pollutant	Stack lb/mmBtu	S Coal Content (%)	S Coal lb/mmBtu
Acid Mist	0.004	4.33	7.18

TABLE 6
Coal Analysis - Metals

Pollutant	Coal Content ng/g	HHV (Btu/lb)	Coal Emission Rate (lb/mmbtu Btu)
Beryllium (Be)	1808.3	12,116	1.49E-04
Lead (Pb)	7033.3	12,116	5.81E-04
Mercury (Hg)	118.3	12,116	9.76E-06

TABLE 7
Coal Analysis – Chlorine/Fluorine

Pollutant	Coal Content	HHV (Btu/lb)	Coal Emission Rate (lb/mmBtu)
Chlorine (Cl)	0.031 %	11,881	0.026
Fluorine (F)	119.5 ppm	11,881	99.6

TABLE 8
Coal Analysis – S

Pollutant	Coal Content (%)	HHV (Btu/lb)	Coal Emission Rate (lb/mmBtu)
Sulfur (S)	4.32	12,054	7.179

TABLE 9
Summary of Particulate Emissions
Gilbert Unit 3

Source	Concentration gr/dscf	Concentration gr/dscm	Emission rate lb/hr
Limestone Silo	0.001	0.025	0.07
Fly Ash Silo	0.001	0.034	0.05
Bottom Ash Silo	0.001	0.032	0.03

4.0 Description Of Combustion Units

Gilbert Unit 3 is a coal fired Circulating Fluidized Bed (CFB) steam generating utility boiler located near Maysville, KY. The unit is equipped with a baghouse, flash dryer absorber, and SNCR for control of PM, SO_2 and NOx emissions, respectively. No. 2 fuel oil is used for startup and unit stabilization. The nominal heat input rating is 2,500 mmBtu/hour. The flue gas is exhausted into the Unit 2 stack.

The Unit 3 stack height is approximately 650 feet. The test ports are located 436 feet upstream and 134 feet downstream from the nearest flow disturbance, 29.1 diameters and 8.9 diameters, respectively.

TABLE 10
Isokinetic Sampling Summary
Trace Metals - EPA Method 29

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:		1	2	3
Date:		6/8/2005	6/8/2005	6/8/2005
Run Time:	Start	8:21	11:12	13:50
	End	10:33	13:20	15:59
Unit Load (MW):		299	299	299
DN - Nozzle Diameter:		0.217	0.217	0.217
Pbar - Barometric Pressure:		29.35	29.35	29.35
TT - Sampling Time:		120	120	120
VM - Meter Volume:		104.146	109.954	112.883
TM - Avg. Meter Temp (F):		81	89	93
PM - Avg. Delta H (in. of H2O):		2.750	2.683	2.708
Y - Meter Calibration Factor:		1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):		100.400	104.349	106.321
Vlc - Volume Water Collected:		353.7	317.2	352.1
%M - Percent Moisture:		14.2	12.5	13.5
Bws - Mole Fraction, Dry:		0.142	0.125	0.135
%CO2 - Carbon Dioxide, Dry:		13.8	13.8	13.8
%O2 - Oxygen, Dry:		5.2	5.2	5.2
%EA - Excess Air		32.1	32.1	32.1
MD - Dry Molecular Weight:		30.42	30.42	30.42
MS - Wet Molecular Weight:		28.65	28.86	28.74
A - Stack Area, SQ.FT:		176.70	176.70	176.70
PS - Static Press. (in. of Hg):		29.27	29.27	29.27
TS - Stack Temp. (F):		166	167	167
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		79.8	78.7	79.3
QS - Stack Gas Volume (DSCFM):		598,834	601,489	599,360
QA - Stack Gas Volume (ACFM):		846,084	834,802	840,495
%I - Isokinetic Ratio:		96.2	99.5	101.8
Emission Rate (lb/mmBtu):				
	Beryllium	2.9E-08	0.0E+00	0.0E+00
	Lead	4.0E-07	2.8E-06	1.8E-06
	Mercury	1.1E-06	8.7E-07	1.1E-06
AVG				**Limit**
	Beryllium		**9.5E-09**	**1.46E-05**
	Lead		**1.7E-06**	**6.3E-06**
	Mercury		**1.0E-06**	**2.65E-06**

TABLE 11
Isokinetic Sampling Summary
HCl/HF - EPA Method 26A

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:	1	2	3
Date:	6/9/2005	6/9/2005	6/9/2005
Run Time: Start	7:00	8:30	10:07
End	8:09	9:38	11:16
Unit Load (MW):	190	190	190
DN - Nozzle Diameter:	0.217	0.217	0.217
Pbar - Barometric Pressure:	29.4	29.40	29.40
TT - Sampling Time:	60	60	60
VM - Meter Volume:	53.721	52.726	54.191
TM - Avg. Meter Temp (F):	79	82	86
PM - Avg. Delta H (in. of H2O):	2.667	2.700	2.650
Y - Meter Calibration Factor:	1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):	52.070	50.839	51.783
Vlc - Volume Water Collected:	176.4	174.6	176.4
%M - Percent Moisture:	13.8	13.9	13.8
Bws - Mole Fraction, Dry:	0.138	0.139	0.138
%CO2 - Carbon Dioxide, Dry:	13.9	13.8	13.8
%O2 - Oxygen, Dry:	5.2	5.3	5.3
%EA - Excess Air	32.2	33.0	33.0
MD - Dry Molecular Weight:	30.43	30.42	30.42
MS - Wet Molecular Weight:	28.72	28.69	28.70
A - Stack Area, SQ.FT:	176.70	176.70	176.70
PS - Static Press. (in. of Hg):	29.32	29.32	29.32
TS - Stack Temp. (F):	165	166	166
CP - Pitot Coefficient:	0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):	78.6	79.0	78.4
QS - Stack Gas Volume (DSCFM):	594,423	596,471	592,333
QA - Stack Gas Volume (ACFM):	832,952	838,075	831,655
%I - Isokinetic Ratio:	100.5	97.8	100.3

Emission Rate (lb/mmBtu):

HCl	5.5E-05	5.7E-05	5.6E-05
HF	5.5E-05	5.7E-05	5.6E-05
AVG			**Limit**
HCl		**5.6E-05**	**3.5E-03**
HF		**5.6E-05**	**4.7E-04**

TABLE 12

Isokinetic Sampling Summary
Acid Mist - EPA Method 8

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:	1	2	3
Date:	6/9/2005	6/9/2005	6/9/2005
Run Time: Start	12:45	15:36	17:36
End	13:57	16:45	18:45
Unit Load (MW):	299	299	299
DN - Nozzle Diameter:	0.217	0.217	0.217
Pbar - Barometric Pressure:	29.4	29.40	29.40
TT - Sampling Time:	60	60	60
VM - Meter Volume:	56.585	54.071	56.039
TM - Avg. Meter Temp (F):	89	91	94
PM - Avg. Delta H (in. of H2O):	2.700	2.650	2.633
Y - Meter Calibration Factor:	1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):	53.806	51.269	52.853
Vlc - Volume Water Collected:	132.6	157.1	167.8
%M - Percent Moisture:	10.4	12.6	13.0
Bws - Mole Fraction, Dry:	0.104	0.126	0.130
%CO2 - Carbon Dioxide, Dry:	13.8	13.9	13.9
%O2 - Oxygen, Dry:	5.2	5.2	5.3
%EA - Excess Air	32.1	32.2	33.1
MD - Dry Molecular Weight:	30.42	30.43	30.44
MS - Wet Molecular Weight:	29.12	28.86	28.82
A - Stack Area, SQ.FT:	176.70	176.70	176.70
PS - Static Press. (in. of Hg):	29.32	29.32	29.32
TS - Stack Temp. (F):	167	167	166
CP - Pitot Coefficient:	0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):	78.5	78.3	78.1
QS - Stack Gas Volume (DSCFM):	615,600	598,455	594,915
QA - Stack Gas Volume (ACFM):	832,267	829,679	827,865
%I - Isokinetic Ratio:	100.3	98.3	101.9

Emission Rate (lb/mmBtu):

	H2SO4	0.004	0.004	0.005
AVG				**Limit**
	H2SO4		**0.004**	**0.005**

TABLE 13
SAMPLING SUMMARY
NOx/SO_2/CO/VOC - EPA Methods 3A, 6C, 7E. 10 and 25A

Client: East Kentucky Power Cooperative
Plant: Gilbert
Unit: 3
Location: Stack

	Run 1	Run 2	Run 3
Date	6/13/2005	6/13/2005	6/13/2005
Start Time	10:08	11:23	12:35
End Time	11:08	12:23	13:35
Unit Load (MW)	296	295	292
Corrected NOx Concentration (ppm)	58.4	55.5	55.4
Corrected O2 (%)	5.5	5.4	5.6
Corrected CO2 (%)	13.6	13.6	13.5
F-factor	9780	9780	9780
NOx Emissions (lb/mmBtu)	0.093	0.087	0.088
Average NOx Emissions (lb/mmBtu)		**0.09**	
Corrected SO2 Concentration (ppm)	53.4	77.2	101.1
SO2 Emissions (lb/mmBtu)	0.118	0.169	0.224
Average SO2 Emissions (lb/mmBtu)		**0.17**	
Corrected CO Concentration (ppm)	67.0	64.1	60.20
CO Emissions (lb/mmBtu)	0.065	0.061	0.059
Average CO Emissions (lb/mmBtu)		**0.06**	
Corrected VOC Concentration (ppm)	1.0	0.9	0.7
VOC Emissions (lb/mmBtu)	0.001	0.001	0.001
Average VOC Emissions (lb/mmBtu)		**0.001**	

TABLE 14

Isokinetic Sampling Summary
Particulate - EPA Method 5
Baseline

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:	1	2	3
Date:	6/16/2005	6/16/2005	6/16/2005
Run Time: Start	7:53	9:40	11:10
End	9:01	10:44	12:17
Unit Load (MW):	300	300	300
DN - Nozzle Diameter:	0.196	0.196	0.196
Pbar - Barometric Pressure:	29.44	29.44	29.44
TT - Sampling Time:	60	60	60
VM - Meter Volume:	40.26	40.196	40.617
TM - Avg. Meter Temp (F):	73	78	80
PM - Avg. Delta H (in. of H2O):	1.691	1.628	1.562
Y - Meter Calibration Factor:	1.01	1.01	1.01
VMSTD - Std. Gas Volume (SCF):	39.565	39.123	39.428
Vlc - Volume Water Collected:	121.2	125.8	126.1
%M - Percent Moisture:	12.6	13.2	13.1
Bws - Mole Fraction, Dry:	0.126	0.132	0.131
%CO2 - Carbon Dioxide, Dry:	13.8	13.8	13.8
%O2 - Oxygen, Dry:	5.3	5.3	5.3
%EA - Excess Air	33.0	33.0	33.0
MD - Dry Molecular Weight:	30.42	30.42	30.42
MS - Wet Molecular Weight:	28.85	28.79	28.79
A - Stack Area, SQ.FT:	176.70	176.70	176.70
PS - Static Press. (in. of Hg):	29.38	29.38	29.37
TS - Stack Temp. (F):	170	181	174
CP - Pitot Coefficient:	0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):	74.9	74.0	72.1
QS - Stack Gas Volume (DSCFM):	570,988	551,138	543,324
QA - Stack Gas Volume (ACFM):	794,428	784,059	764,532
%I - Isokinetic Ratio:	97.4	99.8	102.1
Mg - Catch weight:	6.9	5.4	6.7
Gr/DSCF - Emission Concentration:	0.003	0.002	0.003
LB/MMBtu - Emission Concentration	0.005	0.004	0.005

Average Gr/DSCF	0.002	**Limit**
Average LB/MMbtu	**0.005**	**0.015**

TABLE 15
Isokinetic Sampling Summary
Particulate - EPA Method 5
17% Opacity

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:		**1 -17%**	**2-17%**	**3-17%**
Date:		8/17/2005	8/17/2005	8/17/2005
Run Time:	Start	8:10	10:05	11:40
	End	9:19	11:14	12:49
Unit Load (MW):		290	289	290
DN - Nozzle Diameter:		0.190	0.190	0.185
Pbar - Barometric Pressure:		29.7	29.70	29.70
TT - Sampling Time:		60	60	60
VM - Meter Volume:		36.982	37.048	35.873
TM - Avg. Meter Temp (F):		83	88	90
PM - Avg. Delta H (in. of H2O):		1.283	1.292	1.183
Y - Meter Calibration Factor:		1.01	1.01	1.01
VMSTD - Std. Gas Volume (SCF):		36.153	35.918	34.627
Vlc - Volume Water Collected:		102	107	109
%M - Percent Moisture:		11.7	12.3	12.9
Bws - Mole Fraction, Dry:		0.117	0.123	0.129
%CO2 - Carbon Dioxide, Dry:		13.9	13.9	13.7
%O2 - Oxygen, Dry:		5.3	5.2	5.4
%EA - Excess Air		33.1	32.2	33.8
MD - Dry Molecular Weight:		30.44	30.43	30.41
MS - Wet Molecular Weight:		28.98	28.90	28.81
A - Stack Area, SQ.FT:		176.70	176.70	176.70
PS - Static Press. (in. of Hg):		29.61	29.61	29.61
TS - Stack Temp. (F):		174	175	175
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		75.1	75.5	75.4
QS - Stack Gas Volume (DSCFM):		579,507	577,685	573,147
QA - Stack Gas Volume (ACFM):		796,521	800,273	799,312
%I - Isokinetic Ratio:		93.4	93.1	95.4
Mg - Catch weight:		80.2	83.3	86.0
Gr/DSCF - Emission Concentration:		0.034	0.036	0.038
LB/MMBtu - Emission Concentration:		0.064	0.067	0.072

Average Gr/DSCF	0.036	**Limit**
Average LB/MMbtu	**0.068**	**0.015**

TABLE 16
Isokinetic Sampling Summary
Particulate - EPA Method 5
8.5% Opacity

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:		**1-8.5%**	**2-8.5%**	**3-8.5%**
Date:		8/17/2005	8/17/2005	8/17/2005
Run Time:	Start	13:25	14:52	16:21
	End	14:34	16:01	17:28
Unit Load (MW):		285	284	289
DN - Nozzle Diameter:		0.190	0.190	0.185
Pbar - Barometric Pressure:		29.7	29.70	29.70
TT - Sampling Time:		60	60	60
VM - Meter Volume:		37.039	37.326	36.233
TM - Avg. Meter Temp (F):		92	93	95
PM - Avg. Delta H (in. of H2O):		1.275	1.267	1.183
Y - Meter Calibration Factor:		1.01	1.01	1.01
VMSTD - Std. Gas Volume (SCF):		35.650	35.812	34.657
Vlc - Volume Water Collected:		113	110	111
%M - Percent Moisture:		13.0	12.6	13.1
Bws - Mole Fraction, Dry:		0.130	0.126	0.131
%CO2 - Carbon Dioxide, Dry:		13.8	13.8	13.9
%O2 - Oxygen, Dry:		5.3	5.2	5.2
%EA - Excess Air		33.0	32.1	32.2
MD - Dry Molecular Weight:		30.42	30.42	30.43
MS - Wet Molecular Weight:		28.81	28.85	28.80
A - Stack Area, SQ.FT:		176.70	176.70	176.70
PS - Static Press. (in. of Hg):		29.61	29.61	29.61
TS - Stack Temp. (F):		175	175	172
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		75.2	74.9	75.2
QS - Stack Gas Volume (DSCFM):		570,895	571,183	572,992
QA - Stack Gas Volume (ACFM):		796,991	794,292	797,534
%I - Isokinetic Ratio:		93.5	93.8	95.5
Mg - Catch weight:		25.2	28.4	30.6
Gr/DSCF - Emission Concentration:		0.011	0.012	0.014
LB/MMBtu - Emission Concentration:		0.020	0.023	0.025

Average Gr/DSCF	0.012	**Limit**
Average LB/MMbtu	**0.023**	**0.015**

TABLE 17
Isokinetic Sampling Summary
Particulate - EPA Method 5
6% Opacity

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Stack**

Run Number:		**1-6%**	**2-6%**	**3-6%**
Date:		8/18/2005	8/18/2005	8/18/2005
Run Time:	Start	8:00	9:40	11:10
	End	9:09	10:49	12:22
Unit Load (MW):		283	281	282
DN - Nozzle Diameter:		0.190	0.185	0.190
Pbar - Barometric Pressure:		29.4	29.40	29.40
TT - Sampling Time:		60	60	60
VM - Meter Volume:		36.914	36.104	37.008
TM - Avg. Meter Temp (F):		88	91	93
PM - Avg. Delta H (in. of H2O):		1.283	1.183	1.275
Y - Meter Calibration Factor:		1.01	1.01	1.01
VMSTD - Std. Gas Volume (SCF):		35.405	34.413	35.158
Vlc - Volume Water Collected:		111	111	110
%M - Percent Moisture:		12.9	13.2	12.8
Bws - Mole Fraction, Dry:		0.129	0.132	0.128
%CO2 - Carbon Dioxide, Dry:		14.0	14.0	14.0
%O2 - Oxygen, Dry:		5.2	5.2	5.2
%EA - Excess Air		32.2	32.2	32.2
MD - Dry Molecular Weight:		30.45	30.45	30.45
MS - Wet Molecular Weight:		28.85	28.81	28.85
A - Stack Area, SQ.FT:		176.70	176.70	176.70
PS - Static Press. (in. of Hg):		29.31	29.31	29.31
TS - Stack Temp. (F):		171	172	172
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		75.5	75.6	75.3
QS - Stack Gas Volume (DSCFM):		571,374	569,240	569,763
QA - Stack Gas Volume (ACFM):		800,455	801,586	798,411
%I - Isokinetic Ratio:		92.7	95.4	92.3
Mg - Catch weight:		16.5	16.5	17.7
Gr/DSCF - Emission Concentration:		0.007	0.007	0.008
LB/MMBtu - Emission Concentration:		0.013	0.014	0.014

Average Gr/DSCF	0.007	**Limit**
Average LB/MMbtu	**0.014**	**0.015**

TABLE 18
Isokinetic Sampling Summary
Particulate - EPA Methid 17
Limestone Baghouse

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Limestone Baghouse**

Run Number:		**1**	**2**	**3**
Date:		6/15/2005	6/15/2005	6/15/2005
Run Time:	Start	7:50	9:18	10:43
	End	8:53	10:21	11:46
DN - Nozzle Diameter:		0.220	0.220	0.220
Pbar - Barometric Pressure:		29.55	29.55	29.55
TT - Sampling Time:		60	60	60
VM - Meter Volume:		47.803	49.001	49.671
TM - Avg. Meter Temp (F):		90	94	95
PM - Avg. Delta H (in. of H2O):		1.932	2.022	2.049
Y - Meter Calibration Factor:		1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):		45.501	46.346	46.895
Vlc - Volume Water Collected:		24	26	25
%M - Percent Moisture:		2.4	2.6	2.4
Bws - Mole Fraction, Dry:		0.024	0.026	0.024
%CO2 - Carbon Dioxide, Dry:		0.0	0.0	0.0
%O2 - Oxygen, Dry:		20.9	20.9	20.9
MD - Dry Molecular Weight:		28.84	28.84	28.84
MS - Wet Molecular Weight:		28.57	28.56	28.57
A - Stack Area, SQ.FT:		4.00	4.00	4.00
PS - Static Press. (in. of Hg):		29.53	29.53	29.53
TS - Stack Temp. (F):		96	96	97
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		54.1	55.7	56.2
QS - Stack Gas Volume (DSCFM):		11,885	12,206	12,307
QA - Stack Gas Volume (ACFM):		12,987	13,371	13,487
%I - Isokinetic Ratio:		96.7	95.9	96.3
Mg - Catch weight:		2.0	2.1	2.2
Gr/DSCF - Emission Concentration:		0.001	0.001	0.001
Gr/DSCM - Emission Concentration:		0.024	0.025	0.026
LBS/HR - Emission Rate:		0.07	0.07	0.08

Average Gr/DSCF	0.001
Average Gr/DSCM	0.025
Average LBS/HR	**0.07**

TABLE 19
Isokinetic Sampling Summary
Particulate - EPA Method 17
Bottam Ash Silo

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Bottom Ash Silo Baghouse**

Run Number:		1	2	3
Date:		6/14/2005	6/14/2005	6/14/2005
Run Time:	Start	9:08	10:20	11:50
	End	10:05	11:33	13:02
DN - Nozzle Diameter:		0.250	0.250	0.250
Pbar - Barometric Pressure:		29.85	29.85	29.85
TT - Sampling Time:		62.5	62.5	62.5
VM - Meter Volume:		42.105	39.091	38.72
TM - Avg. Meter Temp (F):		103	100	102
PM - Avg. Delta H (in. of H2O):		1.233	1.185	1.489
Y - Meter Calibration Factor:		0.98	0.98	0.98
VMSTD - Std. Gas Volume (SCF):		38.706	36.157	35.675
Vlc - Volume Water Collected:		15	22	25
%M - Percent Moisture:		1.8	2.8	3.2
Bws - Mole Fraction, Dry:		0.018	0.028	0.032
%CO2 - Carbon Dioxide, Dry:		0.0	0.0	0.0
%O2 - Oxygen, Dry:		20.9	20.9	20.9
MD - Dry Molecular Weight:		28.84	28.84	28.84
MS - Wet Molecular Weight:		28.64	28.53	28.49
A - Stack Area, SQ.FT:		3.40	3.40	3.40
PS - Static Press. (in. of Hg):		29.86	29.86	29.86
TS - Stack Temp. (F):		143	139	136
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		36.0	35.2	33.4
QS - Stack Gas Volume (DSCFM):		6,312	6,144	5,839
QA - Stack Gas Volume (ACFM):		7,350	7,183	6,817
%I - Isokinetic Ratio:		97.9	94.0	97.6
Mg - Catch weight:		2.5	2.5	1.9
Gr/DSCF - Emission Concentration:		0.001	0.001	0.001
Gr/DSCM - Emission Concentration:		0.035	0.038	0.029
LBS/HR - Emission Rate:		0.05	0.06	0.04

Average Gr/DSCF	0.001
Average Gr/DSCM	0.034
Average LBS/HR	**0.05**

TABLE 20
Isokinetic Sampling Summary
Particulate - EPA Method 17
Fly Ash Silo

Client: **East Kentucky Power Cooperative**
Plant: **Gilbert 3**
Location: **Flyash Silo Baghouse**

		1	2	3
Run Number:		1	2	3
Date:		6/16/2005	6/16/2005	6/16/2005
Run Time:	Start	7:45	9:15	10:40
	End	8:57	10:17	11:53
DN - Nozzle Diameter:		0.280	0.280	0.280
Pbar - Barometric Pressure:		29.88	29.88	29.88
TT - Sampling Time:		62.5	62.5	62.5
VM - Meter Volume:		35.261	36.28	36.197
TM - Avg. Meter Temp (F):		71	75	79
PM - Avg. Delta H (in. of H2O):		0.954	0.987	0.976
Y - Meter Calibration Factor:		0.98	0.98	0.98
VMSTD - Std. Gas Volume (SCF):		34.397	35.087	34.744
Vlc - Volume Water Collected:		34	32	35
%M - Percent Moisture:		4.4	4.1	4.5
Bws - Mole Fraction, Dry:		0.044	0.041	0.045
%CO2 - Carbon Dioxide, Dry:		0.0	0.0	0.0
%O2 - Oxygen, Dry:		20.9	20.9	20.9
MD - Dry Molecular Weight:		28.84	28.84	28.84
MS - Wet Molecular Weight:		28.35	28.39	28.35
A - Stack Area, SQ.FT:		3.40	3.40	3.40
PS - Static Press. (in. of Hg):		29.89	29.89	29.89
TS - Stack Temp. (F):		96	101	101
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		24.1	24.5	24.3
QS - Stack Gas Volume (DSCFM):		4,452	4,493	4,459
QA - Stack Gas Volume (ACFM):		4,909	4,988	4,964
%I - Isokinetic Ratio:		98.3	99.4	99.2
Mg - Catch weight:		2.9	1.9	1.3
Gr/DSCF - Emission Concentration:		0.001	0.001	0.001
Gr/DSCM - Emission Concentration:		0.046	0.029	0.020
LBS/HR - Emission Rate:		0.05	0.03	0.02

Average Gr/DCFM	0.001
Average Gr/DSCM	0.032
Average LBS/HR	**0.03**

5.0 Description of CEMS

The Gilbert Unit 3 CEMS is a dilution extraction system (100:1 ratio) that measures SO_2, NOx, CO and CO_2 concentrations and flow at the sampling location. The CEMS analyzers include a Thermo Environmental Model 43C SO_2 analyzer, Thermo Environmental Model 42C NOx analyzer, Thermo Environmental Model 41C CO_2 analyzer, Environmental Model 48C CO analyzer and Teledyne Ultraflow Model 150. The recording and reporting requirements are performed by an ESC 8816 data logger and computerized data acquisition and handing system (DAHS).

Unit 3 CEMS

(1) Thermo Environmental SO_2 - 43C - Serial No. 43C-0417006736
(1) Thermo Environmental NOx - 42C - Serial No. 42C-0417006733
(1) Thermo Environmental CO_2 -41CHL - Serial No. 41C-0417006740
(1) Thermo Environmental CO -41CHL - Serial No. 48C-0417006736
(1) Teledyne Ultraflow 150 - Serial No. 1500184

The data acquisition and handling system utilizes a Fc factor (scf/mmBtu) of 1800 based on the fuel to calculate NOx emissions in lbs/mmBtu. The analyzers measure on a wet basis. The data acquisition and handling system reports the volumetric flow data in standard cubic feet per hour (SCFH).

6.0 Sampling Program Procedures

The following test methods were utilized during the test program:

EPA Method 1	Sample and Velocity Traverse for Stationary Sources
EPA Method 2	Determination of Stack Gas Velocity and Volumetric Flow Rate
EPA Method 3A	Gas Analysis for CO_2, O_2, Excess Air and Dry Molecular Weight (Instrumental Analyzer Method)
EPA Method 4	Determination of Moisture Content in Stack Gas
EPA Method 5	Determination of Particulate Emissions from Stationary Sources
EPA Method 6C	Determination of SO_2 Emissions from Stationary Sources (Instrumental Analyzer Method)
EPA Method 7E	Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Method)
EPA Method 8	Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
EPA Method 10	Determination of Carbon Monoxide Emissions from Stationary Sources
EPA Method 17	Determination of Particulate Emissions from Stationary Sources In-stack Filter
EPA Method 25A	Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer

EPA Method 26A	Determination of Hydrogen Chloride Emissions from Stationary Sources
EPA Method 29	Determination of Metals Emissions in Exhaust Gases from Stationary Sources

The sampling was conducted in a vertical section of the stack, which is 223.25 inches in diameter. There are four (4) test ports orientated 90 degrees apart. The test ports are located 86 feet downstream and 18 feet upstream from the nearest flow disturbance, 4.6 diameters and 1.0 diameters, respectively. The sampling was at six (6) traverse points for each port, 24 total points. Test runs were conducted in triplicate for all parameters, with each being a minimum of 60 minutes in duration.

6.1 Particulate – EPA Method 5

The stack particulate emissions were determined in accordance with procedures outlined in EPA Method 5. The flue gas sample was extracted isokinetically from the gas stream and the particulate emissions were determined gravimetrically from the amount of particulate matter collected in the nozzle, probe, filter holder and filter. The probe and filter were both maintained at approximately 250° F. The sampling train consists of the following equipment connected in series:

Glass lined probe and stainless steel nozzle

Glass fiber filter within a heated filter holder with teflon support

A modified Greenburg-Smith impinger containing 100 ml of distilled water

A Greenburg-Smith impinger containing 100 ml of distilled water

A modified Greenburg-Smith impinger, empty

A modified Greenburg-Smith impinger containing approximately 250g of silica gel

The sample volume was measured by passing it through a calibrated dry gas meter. An S-type pitot tube was attached to the probe to measure stack gas velocity and to maintain isokinetic sampling. A K-type thermocouple was also attached to the probe to measure the gas temperature.

After the run, the probe, nozzle and connecting glassware ahead of the filter were brushed and rinsed with acetone. The washings were retained in labeled, glass sample containers for analysis. The impinger contents were measured for increase in volume. The silica gel was returned to the original tared container and weighed to determine moisture gain.

Particulate matter was determined by using the analytical procedures outlined in EPA Method 5.

a. Dry each filter at 220° F, desiccate to a constant weight and record the results to 0.1 mg.

b. Measure the acetone rinse. Evaporate the acetone rinse in a tared beaker, desiccate to a constant weight and record results to 0.1 mg.

6.2 SO_2, NOx, CO and CO_2

A sample was continuously extracted and introduced into a Thermo Environmental Model 10 Chemiluminescent NOx analyzer, Western Research 721 ATM SO_2 analyzer, Thermo Environmental Model 48 CO analyzer and a Servomex 1400 O_2/CO_2 analyzer for determination of gas concentrations. The sample was extracted through a heated stainless steel probe, heated sample line and sample conditioner to dry the sample before it enters the analyzers. A sample flow control system was used to control the flow into the analyzers. The analyzers were calibrated prior to starting the testing with EPA Protocol 1, calibration gases. A system bias check was performed before each run by introducing the zero and upscale gas at the back end of the sample probe. The system bias check was repeated at the end of each test run to determine the analyzer zero and calibration drift.

The NOx analyzer span was 0-100 ppm. The calibration gases that were utilized were zero, 40-60% (45.3 ppm) and 80-100% (88.4 ppm) of span. The SO_2 analyzer span was 0-150 ppm. The calibration gases that were utilized were zero, 40-60% (79.35 ppm) and 80-100% (125.0 ppm) of span. The CO analyzer span was 0-100 ppm. The calibration gases that were utilized were zero, 30% (30.43 ppm), 60% (60.5) and 90% (89.0 ppm) of span. The O_2/CO_2 analyzer spans were 0-25% and 0-20%, respectively. The O_2 calibration gases utilized were 12.47% and 22.63%. The CO_2 calibration gases were 9.85% and 17.88%.

Reference Method Analyzers:

Manufacturer	Model	Pollutant	Span
TECO	10AR	NOx	0-100 ppm
Western Research	721-M	SO_2	0-150 ppm
TECO	48	CO	0-100 ppm
Servomex	1400B	CO_2/O_2	0-20%/0-25%

6.3 Sulfuric Acid Mist - EPA Method 8

Acid Mist emissions were determined in accordance with procedures outlined in EPA Method 8. A gas sample was isokinetically extracted from the flue gas and the sulfur oxides are collected in the impingers and measured by barium-thorin titration. The sampling train consists of the following equipment connected in series:

Glass lined probe and glass nozzle

A modified Greenburg-Smith impinger containing 100 ml of an 80% isopropanol solution

Glass fiber filter with in a filter holder with teflon support

A Greenburg-Smith impinger containing 100 ml of a 3% hydrogen peroxide solution

A modified Greenburg-Smith impinger containing 100 ml of a 3% hydrogen peroxide solution

A modified Greenburg-Smith impinger containing 250g of silica gel

The sample volume was measured by passing it through a calibrated dry gas meter. An S-type pitot tube was attached to the probe to measure stack gas velocity and to maintain isokinetic sampling. A K-type thermocouple was attached to the probe to measure the gas temperature.

After the run, the probe was disconnected from the sample train. The remaining portion was purged for 15 minutes at the average sampling rate of the run.

The isopropanol impinger and all glassware ahead of the filter were brushed and rinsed with 80% isopropanol and the washings were retained for SO_3/H_2SO_4 analysis. The filter was removed and saved for SO_3/H_2SO_4 analysis. The peroxide impinger contents were recovered and the impingers and connecting glassware were rinsed with distilled water and the rinses were retained for SO_2 analysis. Each sample was analyzed by barium thorin titration to determine sulfur trioxide and sulfur dioxide content.

6.4 Particulate Matter – EPA Method 17

The ash and limestone handling particulate emissions were determined in accordance with procedures outlined in EPA Method 17. The flue gas sample was extracted isokinetically from the gas stream and the particulate emissions were determined gravimetrically from the amount of particulate matter collected in the nozzle, filter holder and filter. The sampling train consists of the following equipment connected in series:

Stainless steel nozzle and filter holder

30 x 100 glass fiber thimble

A modified Greenburg-Smith impinger containing 100 ml of distilled water

A Greenburg-Smith impinger containing 100 ml of distilled water

A modified Greenburg-Smith impinger, empty

A modified Greenburg-Smith impinger containing approximately 250g of silica gel

The sample volume was measured by passing it through a calibrated dry gas meter. An S-type pitot tube was attached to the probe to measure stack gas velocity and to maintain isokinetic sampling. A K-type thermocouple was also attached to the probe to measure the gas temperature.

After the run, the nozzle and filter holder ahead of the filter were brushed and rinsed with acetone. The washings were retained in labeled, glass sample containers for analysis. The impinger contents were measured for increase in volume. The silica gel was returned to the original tared container and weighed to determine moisture gain.

Particulate matter was determined by using the analytical procedures outlined in EPA Method 17.

a. Dry each filter at 220° F, desiccate to a constant weight and record the results to 0.1 mg.
b. Measure the acetone rinse. Evaporate the acetone rinse in a tared beaker, desiccate to a constant weight and record results to 0.1 mg.

6.5 Non-Methane Hydrocarbons - EPA Method 25A

A sample was continuously extracted and introduced into a California Analytical 300-HFID, flame ionization analyzer for determination of concentration. The sample was extracted through a heated stainless steel probe and heated sample line to the analyzer. A sample flow control system was used to control the flow into the analyzer. The analyzer was calibrated prior to starting the testing with EPA Protocol, calibration gases. A system bias and drift check was performed at the end of each test run to determine the analyzer zero and calibration drift.

The analyzer span was 0-10 ppm. The calibration gases that were utilized are zero, 30% (2.92 ppm), 60% (5.05 ppm) and 90% (8.94 ppm) of span.

6.6 HCl/HF - EPA Method 26A

The HCl and HF emissions were determined in accordance with procedures outlined in EPA Method 26A. The flue gas sample was extracted isokinetically from the gas stream and collected on a filter and in absorbing solutions. The filter collects particulate matter including halide salts. Acidic and alkaline absorbing solutions collect the gaseous hydrogen halides and halogens, respectively. The hydrogen halides emissions were solubilized in the acidic solution. The halogens pass through to the alkaline solution where they were hydrolyzed. Sodium thiosulfate is added to the alkaline solution to assure reaction with the hypohalous acid. The halide ions in the acidic solutions are measured by ion chromatography. The probe and filter are both maintained at approximately 250° F. The sampling train consists of the following equipment connected in series:

Glass lined probe and glass nozzle

Glass fiber filter within a heated filter holder with teflon support

Two Greenburg-Smith impingers containing 100 ml of 0.1N H_2SO_4

Two modified Greenburg-Smith impingers containing 100 ml of 0.1N NaOH

A modified Greenburg-Smith impinger containing approximately 250 mg of silica gel

The sample volume is measured by passing it through a calibrated dry gas meter. After each run the impinger contents are measured for increase in volume. The contents of the first two impingers and distilled water rinses are retained for analysis.

6.7 Trace Metals - EPA Method 29 - Be, Hg and Pb

The trace metals emissions were determined in accordance with procedures outlined in EPA Method 29. The flue gas sample was extracted isokinetically from the gas stream, each sample run was two hours in duration. The probe and filter were both maintained at 250° F. The sampling train consists of the following equipment connected in series:

Glass lined probe and glass nozzle

Glass fiber filter within a heated filter holder with teflon support

A modified Greenburg-Smith impinger containing 100 ml of 5% HNO_3/10% H_2O_2

A Greenburg-Smith impinger containing 100 ml of 5% HNO_3/10% H_2O_2

A modified Greenburg-Smith impinger, empty

Two (2) modified Grenburg-Smith impingers containing 100 ml of a 4% $KMnO_4$/10% H_2SO_4 solution

A modified Greenburg-Smith impinger containing 250g of silica gel

The sample volume was measured by passing it through a calibrated dry gas meter. An S-type pitot tube was attached to the probe to measure stack gas velocity and to maintain isokinetic sampling. A K-type thermocouple was also attached to the probe to measure the gas temperature.

After each run, the probe, nozzle and front half of the filter housing were rinsed with 0.1N HNO_3. The rinse was retained for analysis. The contents of impingers 1 and 2 were measured for increase in volume and were retained with the 0.1N HNO_3 rinses of the impingers and back half of the filter housing. Impinger 3 was measured for volume increase and rinsed with 100 ml of 0.1N HNO_3. The content and rinse were retained for analysis. Impingers 4 and 5 were measured for volume increase and retained for analysis along with the acidic permanganate and distilled water rinses. Any residue left in impingers 4 and 5 was removed with a wash of 8N HCl and retained in a separate container. The silica gel was returned to the original tared container and weighed to determine moisture gain.

The particulate filter was acid digested prior to being combined with the probe rinse for analysis.

All the procedures used for the RATA program were performed in accordance with the Code of Federal Regulations, Title 40, Part 60, Appendix A, and Appendix B, Performance Specifications 2, 3 and 6, and Part 75.

7.0 <u>Operating Conditions</u>

Operating conditions were monitored throughout the duration of the sampling program by EKPC personnel. The testing was performed June 8 - 13 and August 17-18, 2005.

8.0 Quality Assurance Procedures

The quality assurance procedures followed during the testing activities followed guidelines set forth by the previous mentioned methods and the EPA Quality Assurance Handbook for Source Sampling. The specific procedures for this test program are listed below.

8.1 Isokinetic Equipment

The sample nozzles were visually inspected and measured across three different diameters to determine the appropriate nozzle diameter.

The S-type pitot tubes were visually inspected and measured to meet the design specifications of EPA Method 2 for a 0.84 pitot coefficient.

Both legs of the pitot tube were leak checked before and after each sample run.

The stack thermocouples were calibrated prior to the testing and a post-test check was performed after the testing project.

The manometer was leveled and zeroed before each sample run.

The dry gas meter is fully calibrated annually using an EPA intermediate standard. Post -test dry gas meter checks were completed to verify the accuracy of the meter Yi.

Pre-test and post-test leak checks were completed and were less than 0.02 cfm at the highest sampling vacuum.

8.2 Instrumental Methods

Analyzer calibrations, system bias check and drift checks were completed before and after each sample run utilizing EPA Protocol calibration gases.

The NOx analyzer NO_2 to NO converter efficiency is determined in accordance with Section 5.6 of Method 20.

The analyzer interference responses were determined in accordance with Section 5.4 of Method 20 and Section 7.2 through 7.6 of Method 6C.

8.0 Discussion

8.1 Chain of Custody

The metals, acid mist and HCl/HF field samples were collected, sealed and shipped to Maxxam Analytics facility in Burlington, Ontario, Canada under the supervision of Mike Taylor.

The particulate field samples taken June 8-13 were collected sealed, transported and analyzed at the Catalyst facility in Knoxville, TN. The particulate samples collected on August 17 and 18, 2005 were processed on site in the old scrubber laboratory.

The samples were labeled to identify the following:

Client and source
Date
Type of Sample
Run number
Sample location
Sample fraction

8.2 Sampling Conditions and Concerns

No delays or interruptions occurred during the testing.

APPENDIX 1
REFERENCE METHOD TEST RESULTS

Trace Metals

Catalyst Air Management, Inc.
Method 29 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **1** Date: 6/8/05 Start Time: 8:21
End Time: 10:33

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.35	P_{bar}	VOLUME OF MOISTURE:	353.7	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		382.506										
A-1	10.0	391.3	1.70	2.80	72	72	165				32.60	80.8
2	10.0	399.7	1.70	2.80	76	72	166	13.8	5.2	-1.10	32.62	80.9
3	10.0	407.283	1.40	2.30	81	72	167				29.63	73.5
		407.283										
B-1	10.0	415.8	1.80	3.00	81	74	164				33.51	83.1
2	10.0	424.5	1.80	3.00	86	75	167				33.59	83.3
3	10.0	432.720	1.50	2.50	87	77	167				30.67	76.1
		432.720										
C-1	10.0	441.7	1.80	3.00	86	78	164				33.51	83.1
2	10.0	450.7	1.70	2.80	89	79	167				32.65	81.0
3	10.0	459.040	1.40	2.30	89	80	167				29.63	73.5
		459.040										
D-1	10.0	468.4	1.80	3.00	87	81	164				33.51	83.1
2	10.0	477.8	1.80	3.00	90	81	167				33.59	83.3
3	10.0	486.652	1.50	2.50	91	82	166				30.64	76.0
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	120.0	104.146	1.286	2.750		81	166	13.8	5.2	-1.10	32.18	79.8
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.27	$V_{m(std)}$ =	100.400	$V_{w(std)}$ =	16.659	%M=	14.23
B_{ws} =	0.142	M_d =	30.42	M_s =	28.65	%EA=	32.13

STACK GAS VELOCITY =	79.8	AFPS	V_s
STACK GAS VELOCITY =	4,788	AFPM	
STACK GAS VOLUME =	598,834	DSCFM	Q_{std}
STACK GAS VOLUME =	846,084	ACFM	Q_a
ISOKINETIC RATIO =	96.2	%	

EMISSIONS

	Weight (mg)	Concentration (gr/dscf)	Fo Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
Beryllium	0.00010	1.54E-08	2.86E-08	2.86E-08
Lead	0.00140	2.15E-07	4.00E-07	4.01E-07
Mercury	0.00373	5.73E-07	1.07E-06	1.07E-06

Catalyst Air Management, Inc.
Method 29 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **2** Date: 6/8/05 Start Time: 11:12
End Time: 13:20

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.35	P_{bar}	VOLUME OF MOISTURE:	317.2	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		486.867										
A-1	10.0	496.0	1.80	3.00	83	82	165				33.54	82.9
2	10.0	505.4	1.80	3.00	86	82	168	13.8	5.2	-1.10	33.62	83.1
3	10.0	513.962	1.40	2.30	90	83	168				29.65	73.3
		513.962										
B-1	10.0	523.5	1.80	3.00	90	84	165				33.54	82.9
2	10.0	533.0	1.70	2.80	94	85	170				32.73	80.9
3	10.0	541.642	1.40	2.30	95	86	169				29.67	73.3
		541.642										
C-1	10.0	551.2	1.70	2.80	93	87	165				32.60	80.5
2	10.0	560.8	1.80	3.00	95	88	168				33.62	83.1
3	10.0	569.536	1.40	2.30	96	88	168				29.65	73.3
		569.536										
D-1	10.0	578.9	1.70	2.80	94	89	166				32.62	80.6
2	10.0	588.4	1.70	2.80	96	89	167				32.65	80.7
3	10.0	596.821	1.30	2.10	96	90	166				28.53	70.5
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	120.0	109.954	1.273	2.683		89	167	13.8	5.2	-1.10	31.87	78.7
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.27	$V_{m(std)}$ =	104.349	$V_{w(std)}$ =	14.940	%M=	12.52
B_{ws} =	0.125	M_d =	30.42	M_s =	28.86	%EA=	32.13

STACK GAS VELOCITY =	78.7	AFPS	V_s
STACK GAS VELOCITY =	4,724	AFPM	
STACK GAS VOLUME =	601,489	DSCFM	Q_{std}
STACK GAS VOLUME =	834,802	ACFM	Q_a
ISOKINETIC RATIO =	99.5	%	

EMISSIONS

	Weight (ug)	Concentration (ug/dscm)	Fo Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
Beryllium	0.00000	0.00000	0.00000	0.00000
Lead	0.01020	1.51E-06	2.81E-06	2.81E-06
Mercury	0.00315	4.66E-07	8.66E-07	8.68E-07

Catalyst Air Management, Inc.
Method 29 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **3** Date: 6/8/05 Start Time: 13:50
End Time: 15:59

DIAMETER OF NOZZLE: 0.217
AREA OF NOZZLE: 2.57E-04 A_n
BAROMETRIC PRESSURE: 29.35 P_{bar}
GAS METER Y-FACTOR: 1.00 Y

STACK DIAMETER = 180 in
STACK AREA = 176.7 sq. ft.
VOLUME OF MOISTURE: 352.1 V_{lc}
PITOT COEFFICIENT: 0.84 C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		597.086										
A-1	10.0	606.5	1.70	2.80	89	88	164				32.57	80.6
2	10.0	615.7	1.60	2.60	92	88	168	13.8	5.2	-1.10	31.70	78.5
3	10.0	624.043	1.30	2.10	94	88	167				28.55	70.7
		624.043										
B-1	10.0	634.1	1.80	3.00	94	89	165				33.54	83.0
2	10.0	643.8	1.80	3.00	96	89	168				33.62	83.2
3	10.0	652.789	1.50	2.40	98	90	168				30.69	76.0
		652.789										
C-	10.0	662.8	1.80	3.00	95	90	165				33.54	83.0
2	10.0	672.4	1.80	3.00	99	91	167				33.59	83.2
3	10.0	681.225	1.40	2.30	100	92	167				29.63	73.4
		681.225										
D-1	10.0	691.1	1.80	3.00	98	92	165				33.54	83.0
2	10.0	700.9	1.80	3.00	101	93	168				33.62	83.2
3	10.0	709.969	1.40	2.30	102	94	167				29.63	73.4
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	120.0	112.883	1.279	2.708		93	167	13.8	5.2	-1.10	32.02	79.3
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s = 29.27 $V_{m(std)}$ = 106.321 $V_{w(std)}$ = 16.584 %M= 13.49
B_{ws} = 0.135 M_d = 30.42 M_s = 28.74 %EA= 32.13

STACK GAS VELOCITY = 79.3 AFPS V_s
STACK GAS VELOCITY = 4,757 AFPM
STACK GAS VOLUME = 599,360 DSCFM Q_{std}
STACK GAS VOLUME = 840,495 ACFM Q_a
ISOKINETIC RATIO = 101.8 %

EMISSIONS

	Weight (ug)	Concentration (ug/dscm)	Fo Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
Beryllium	0.00000	0.00000	0.00000	0.00000
Lead	0.00660	9.58E-07	1.78E-06	1.78E-06
Mercury	0.00409	5.94E-07	1.10E-06	1.11E-06

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	1155
Plant	SPURLOCK	Nozzle No.	52	Initial Leak (Samp.)	0.000 @ 10"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @ 4"
Test	M-29	TC No.	CAM-5		OK @ 5"
Run	1	P_B	29.35		
Date	6-8-05	Ambient Temp	71	Final Leak (Samp.)	0.000 @ 5"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK @ 5"
ΔH	1.60 Y_i 1.00				OK @ 6"

K = 1.64

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE° F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	821		382.506									
A-1		10	391.3	1.7	2.8	165	248	250	72	72	65	2.0
2		20	399.7	1.7	2.8	166	246	252	76	72	57	2.0
3	851	30	407.283	1.4	2.3	167	247	257	81	72	51	2.0
	855		407.283									
B-1		40	415.8	1.8	3.0	164	249	257	81	74	55	2.5
2		50	424.5	1.8	3.0	167	246	256	86	75	54	3.0
3	925	60	432.720	1.5	2.5	167	245	257	87	77	57	2.5
	929		432.720									
C-1		70	441.7	1.8	3.0	164	245	246	86	78	59	3.0
2		80	450.7	1.7	2.8	167	246	250	89	79	55	2.5
3	959	90	459.040	1.4	2.3	167	246	252	89	80	55	2.0
	1003		459.040									
D-1		100	468.4	1.8	3.0	164	247	251	87	81	59	3.0
2		110	477.8	1.8	3.0	167	245	259	90	81	56	3.0
3	1033	120	486.652	1.5	2.5	166	245	252	91	82	57	3.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gibbons DATE: 6/8/05
SAMPLING TIME: (24 HR CLOCK) 0821 - 1033
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A / 29 AMB. TEMP (°F) 71
TECHNICIAN: Love / Taylor

Rm 1
Metals

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.2	Fuel Type	Fo (calc)
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok NA instrumental
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER_____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	926.8	775.7	679.2	698.4	703.7		784.1	
INITIAL (ml)	732.7	651.3	668.0	692.6	703.4		766.2	
NET (ml)	194.1	124.4	11.2	5.8	0.3		17.9	353.7
TOTALS								353.7

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C 1155			WEIGHED BY	BEAKER NO.				WEIGHED BY
FINAL WEIGHT					FINAL WEIGHT				
INITIAL WEIGHT					INITIAL WEIGHT				
DIFFERENCE					DIFFERENCE				
PARTICULATE CATCH					PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	1157
Plant	SPURLOCK	Nozzle No.	55	Initial Leak (Samp.)	0.000@10"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @5"
Test	M-29	TC No.	CAM-5		OK @6"
Run	2	P_B	29.35		
Date	6-8-05	Ambient Temp	77	Final Leak (Samp.)	0.000@7"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK@3.5"
Δ H	1.60 | Y_1 1.00				OK@4.5"

K=1.64

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE° F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1112		486.867									
D-1		10	496.0	1.8	3.0	165	256	257	83	82	66	3.0
2		20	505.4	1.8	3.0	168	253	249	86	82	64	3.5
3	1142	30	513.962	1.4	2.3	168	255	255	90	83	57	3.0
	1144		513.962									
C-1		40	523.5	1.8	3.0	165	258	263	90	84	60	3.0
2		50	533.0	1.7	2.8	170	245	250	94	85	56	3.0
3	1214	60	541.642	1.4	2.3	169	249	255	95	86	57	3.0
	1217		541.642									
B-1		70	551.2	1.7	2.8	165	249	256	93	87	57	3.0
2		80	560.8	1.8	3.0	168	248	251	95	88	57	3.5
3	1247	90	569.536	1.4	2.3	168	248	255	96	88	58	3.0
	1250		569.536									
A-1		100	578.9	1.7	2.8	166	249	253	94	89	61	3.0
2		110	588.4	1.7	2.8	167	249	249	96	89	58	3.0
3	1320	120	596.821	1.3	2.1	166	250	260	96	90	59	3.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/8/05
SAMPLING TIME: (24 HR CLOCK) 1112 - 1320
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A / 29 AMB. TEMP (°F) 77
TECHNICIAN: Lowe / Taylor

Run 2
Metals

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓ NA instrumental
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER_____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	940.0	808.8	668.7	721.4	700.5		830.2	
INITIAL (ml)	731.9	740.6	657.1	715.3	700.2		807.3	
NET (ml)	208.1	68.2	11.6	6.1	0.3		22.9	317.2
TOTALS								317.2

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C1157			WEIGHED BY	BEAKER NO.				WEIGHED BY
FINAL WEIGHT					FINAL WEIGHT				
INITIAL WEIGHT					INITIAL WEIGHT				
DIFFERENCE					DIFFERENCE				
PARTICULATE CATCH					PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

CATALYST AIR MANAGEMENT, INC.
Air Quality Testing Services
2505 Byington-Solway Road
Knoxville, TN 37931
(865) 531-0075
(865) 531-0750 Fax

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	1155
Plant	SPURLOCK	Nozzle No.	58	Initial Leak (Samp.)	0.000 @10"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @ 3.5
Test	M-29	TC No.	CAM-5		OK @ 4.5
Run	3	P_B	29.35		
Date	6-8-05	Ambient Temp	83	Final Leak (Samp.)	0.000@6"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK@4"
ΔH	1.60 | Y_1 1.00				OK@5"

K = 1.64

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE° F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1350		597.086									
A-1		10	606.5	1.7	2.8	164	245	255	89	88	65	3.0
2		20	615.7	1.6	2.6	168	244	252	92	88	61	3.0
3	1420	30	624.043	1.3	2.1	167	246	255	94	88	57	2.5
	1423		624.043									
B-1		40	634.1	1.8	3.0	165	246	258	94	89	61	3.0
2		50	643.8	1.8	3.0	168	244	253	96	89	60	3.0
3	1453	60	652.789	1.5	2.4	168	245	258	98	90	61	3.0
	1456		652.789									
C-1		70	662.8	1.8	3.0	165	245	256	95	90	60	3.0
2		80	672.4	1.8	3.0	167	244	258	99	91	58	3.5
3	1526	90	681.225	1.4	2.3	167	245	260	100	92	58	3.0
	1529		681.225									
D-1		100	691.1	1.8	3.0	165	245	259	98	92	61	3.5
2		110	700.9	1.8	3.0	168	245	249	101	93	59	3.5
3	1559	120	709.969	1.4	2.3	167	244	262	102	94	60	3.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/8/05
SAMPLING TIME: (24 HR CLOCK) 1350 - 1559
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A/29 AMB. TEMP (°F) 83
TECHNICIAN: Lowe / Taylor

Run 3
Metals

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.3		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____

NA moisture

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	881.3	818.6	619.9	644.2	735.3		834.2	
INITIAL (ml)	637.0	751.5	606.4	640.4	733.1		813.0	
NET (ml)	244.3	67.1	13.5	3.8	2.2		21.2	352.1
TOTALS								352.1

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C1155			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

HCl/HF

Catalyst Air Management, Inc.
Method 26A Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **1** Date: 6/9/05 Start Time: 7:00
End Time: 8:09

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	176.4	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		710.588										
A-1	5.0	714.8	1.80	3.00	75	74	163				33.49	82.9
2	5.0	719.5	1.70	2.80	75	75	166	13.9	5.2	-1.10	32.62	80.7
3	5.0	723.772	1.40	2.30	77	75	166				29.60	73.3
		723.772										
B-1	5.0	728.4	1.80	3.00	78	74	163				33.49	82.9
2	5.0	733.1	1.70	2.80	80	75	166				32.62	80.7
3	5.0	737.500	1.50	2.50	82	75	166				30.64	75.8
		737.500										
C-1	5.0	742.3	1.80	3.00	81	76	164				33.51	82.9
2	5.0	746.9	1.70	2.80	85	76	167				32.65	80.8
3	5.0	751.134	1.40	2.30	85	77	167				29.63	73.3
		751.134										
D-1	5.0	755.7	1.70	2.80	84	78	163				32.54	80.5
2	5.0	760.1	1.60	2.60	86	78	166				31.65	78.3
3	5.0	764.309	1.30	2.10	87	79	166				28.53	70.6
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	53.721	1.270	2.667		79	165	13.9	5.2	-1.10	31.75	78.6
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.32	$V_{m(std)}$ =	52.070	$V_{w(std)}$ =	8.308	%M=	13.76
B_{ws} =	0.138	M_d =	30.43	M_s =	28.72	%EA=	32.18

STACK GAS VELOCITY =	78.6	AFPS	V_s
STACK GAS VELOCITY =	4,714	AFPM	
STACK GAS VOLUME =	594,423	DSCFM	Q_{std}
STACK GAS VOLUME =	832,952	ACFM	Q_a
ISOKINETIC RATIO =	100.5	%	

EMISSIONS

	Weight (mg)	Concentration (gr/dscf)	Fo Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
HCl	0.10	2.96E-05	5.51E-05	5.48E-05

Catalyst Air Management, Inc.
Method 26A Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **2** Date: 6/9/05 Start Time: 8:30
End Time: 9:38

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	174.6	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		764.664										
A-1	5.0	769.1	1.70	2.80	78	78	165				32.60	80.7
2	5.0	773.4	1.60	2.60	78	80	166	13.8	5.3	-1.10	31.65	78.4
3	5.0	777.305	1.30	2.10	82	78	166				28.53	70.6
		777.305										
B-1	5.0	781.9	1.80	3.00	82	78	163				33.49	82.9
2	5.0	786.6	1.80	3.00	84	79	167				33.59	83.2
3	5.0	790.981	1.50	2.50	85	79	167				30.67	75.9
		790.981										
C-1	5.0	795.7	1.80	3.00	84	79	163				33.49	82.9
2	5.0	800.2	1.70	2.80	85	79	167				32.65	80.8
3	5.0	804.430	1.40	2.30	86	80	167				29.63	73.4
		804.430										
D-1	5.0	809.1	1.80	3.00	86	80	164				33.51	83.0
2	5.0	813.3	1.70	2.80	87	80	167				32.65	80.8
3	5.0	817.390	1.50	2.50	88	81	167				30.67	75.9
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	52.726	1.276	2.700		82	166	13.8	5.3	-1.10	31.93	79.0
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.32	$V_{m(std)}$ =	50.839	$V_{w(std)}$ =	8.224	%M=	13.92
B_{ws} =	0.139	M_d =	30.42	M_s =	28.69	%EA=	33.01

STACK GAS VELOCITY =	79.0	AFPS	V_s
STACK GAS VELOCITY =	4,743	AFPM	
STACK GAS VOLUME =	596,471	DSCFM	Q_{std}
STACK GAS VOLUME =	838,075	ACFM	Q_a
ISOKINETIC RATIO =	97.8	%	

EMISSIONS

	Weight (ug)	Concentration (gr/dscf)	Fo Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
HCl	0.10	3.04E-05	5.68E-05	5.66E-05
HF	0.10	3.04E-05	5.68E-05	5.66E-05

Catalyst Air Management, Inc.
Method 26A Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **3** Date: 6/9/05 Start Time: 10:07
End Time: 11:16

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	176.4	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP. IN	METER TEMP. OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		817.734										
A-1	5.0	822.5	1.80	3.00	83	81	164				33.51	83.0
2	5.0	827.0	1.70	2.80	84	81	167	13.8	5.3	-1.10	32.65	80.8
3	5.0	831.497	1.50	2.50	86	81	167				30.67	75.9
		831.497										
B-1	5.0	836.1	1.70	2.80	87	82	164				32.57	80.6
2	5.0	840.7	1.70	2.80	89	82	167				32.65	80.8
3	5.0	845.066	1.40	2.30	91	83	167				29.63	73.3
		845.066										
C-	5.0	849.9	1.80	3.00	90	84	164				33.51	83.0
2	5.0	854.6	1.70	2.80	94	84	167				32.65	80.8
3	5.0	859.066	1.40	2.30	94	85	167				29.63	73.3
		859.066										
D-1	5.0	863.7	1.70	2.80	91	85	164				32.57	80.6
2	5.0	868.3	1.60	2.60	92	85	167				31.67	78.4
3	5.0	872.525	1.30	2.10	93	85	167				28.55	70.7
RESULTS	TT	VM*	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	54.191	1.267	2.650		86	166	13.8	5.3	-1.10	31.69	78.4
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.32	$V_{m(std)}$ =	51.783	$V_{w(std)}$ =	8.308	%M=	13.83
B_{ws} =	0.138	M_d =	30.42	M_s =	28.70	%EA=	33.01

STACK GAS VELOCITY = 78.4 AFPS V_s
STACK GAS VELOCITY = 4,707 AFPM
STACK GAS VOLUME = 592,333 DSCFM Q_{std}
STACK GAS VOLUME = 831,655 ACFM Q_a
ISOKINETIC RATIO = 100.3 %

EMISSIONS

	Weight (ug)	Concentration (gr/dscf)	Fo Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
HCl	0.10	2.98E-05	5.58E-05	5.55E-05
HF	0.10	2.98E-05	5.58E-05	5.55E-05

* Corrected for post leak of 0.03 cfm

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	C-1164
Plant	SPURLOCK	Nozzle No.	CAM-52	Initial Leak (Samp.)	0.000@10"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK@6"
Test	M-26A	TC No.	CAM-5		OK@5"
Run	1	P_B	29.40		
Date	6-9-05	Ambient Temp	73	Final Leak (Samp.)	0.000@6"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK@6"
ΔH	1.60 Y_1 1.00				OK@5"

K=1.64

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	700		710.588									
D-1		5	714.8	1.8	3.0	163	245	257	75	74	61	3.0
2		10	719.5	1.7	2.8	166	243	254	75	75	52	2.5
3	715	15	723.772	1.4	2.3	166	247	249	77	75	54	2.0
	718		723.772									
C-1		20	728.4	1.8	3.0	163	249	260	78	74	54	3.0
2		25	733.1	1.7	2.8	166	248	264	80	75	53	2.5
3	733	30	737.500	1.5	2.5	166	247	262	82	75	55	2.0
	736		737.500									
B-1		35	742.3	1.8	3.0	164	248	256	81	76	58	3.0
2		40	746.9	1.7	2.8	167	248	251	85	76	56	3.0
3	751	45	751.134	1.4	2.3	167	249	254	85	77	57	2.0
	754		751.134									
A-1		50	755.7	1.7	2.8	163	249	247	84	78	59	3.0
2		55	760.1	1.6	2.6	166	247	253	86	78	57	3.0
3	809	60	764.309	1.3	2.1	166	249	254	87	79	57	2.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/9/05
SAMPLING TIME: (24 HR CLOCK) 0700 - 0809
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A / 26A AMB. TEMP (°F) 73
TECHNICIAN: Love / Taylor

Run 1
Method 26A

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok NA manometer
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER_____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	776.7	750.2	773.2	677.1			772.3	
INITIAL (ml)	643.3	725.1	768.6	676.2			759.9	
NET (ml)	133.4	25.1	4.6	0.9			12.4	176.4
TOTALS								176.4

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1164			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

CATALYST AIR MANAGEMENT, INC.
Air Quality Testing Services
2505 Byington Solway Road
Knoxville, TN 37931
(865) 531-0075
(865) 531-0750 Fax

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	C-1165
Plant	SPURLOCK	Nozzle No.	55	Initial Leak (Samp.)	0.000 @ 11"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @ 4"
Test	M-26A	TC No.	CAM-5		OK @ 6"
Run	2	P_B	29.40		
Date	6-9-05	Ambient Temp	74	Final Leak (Samp.)	0.000 @ 6"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK @ 4"
Δ H	1.60 | Y_I 1.00				OK @ 5.5"

K = 1.64

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	830		764.664									
A-1		5	769.1	1.7	2.8	165	245	247	78	78	64	2.5
2		10	773.4	1.6	2.6	166	249	258	78	80	58	2.5
3	845	15	777.305	1.3	2.1	166	245	261	82	78	54	2.5
	848		777.305									
B-1		20	781.9	1.8	3.0	163	245	260	82	78	56	3.5
2		25	786.6	1.8	3.0	167	245	255	84	79	55	3.5
3	903	30	790.981	1.5	2.5	167	244	249	85	79	56	3.0
	906		790.981									
C-1		35	795.7	1.8	3.0	163	245	254	84	79	59	3.5
2		40	800.2	1.7	2.8	167	244	260	85	79	56	3.0
3	921	45	804.430	1.4	2.3	167	244	259	86	80	56	3.0
	923		804.430									
D-1		50	809.1	1.8	3.0	164	243	252	86	80	60	3.5
2		55	813.3	1.7	2.8	167	243	259	87	80	60	3.0
3	938	60	817.390	1.5	2.5	167	243	260	88	81	62	3.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/19/05
SAMPLING TIME: (24 HR CLOCK) 0830-0939
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A/26A AMB. TEMP (°F) 74
TECHNICIAN: Love / Taylor

Rm 2
26A

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok NA volumetric
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER_____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	858.4	766.2	765.0	710.7			839.4	
INITIAL (ml)	731.5	735.2	758.1	710.2			830.1	
NET (ml)	126.9	31.0	6.9	0.5			9.3	174.6
TOTALS								174.6

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1165			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	C-1166
Plant	SPURLOCK	Nozzle No.	58	Initial Leak (Samp.)	0.000 @ 10"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @ 6"
Test	M-26A	TC No.	CAM-5		OK @ 5"
Run	3	P_B	29.40		
Date	6-9-05	Ambient Temp	76	Final Leak (Samp.)	0.030 @ 5.5"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK @ 4.5"
ΔH	1.60 | Y_1 1.00				OK @ 6"

K = 1.64

POINT	TIME ACTUAL	RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1007		817.734									
D-1		5	822.5	1.8	3.0	164	248	247	83	81	63	4.0
2		10	827.0	1.7	2.8	167	249	253	84	81	61	4.0
3	1022	15	831.497	1.5	2.5	167	251	257	86	81	60	3.5
	1025											
C-1		20	836.1	1.7	2.8	164	250	253	87	82	60	4.0
2		25	840.7	1.7	2.8	167	251	253	89	82	58	4.0
3	1040	30	845.066	1.4	2.3	167	250	261	91	83	57	3.5
	1043		845.066									
B-1		35	849.9	1.8	3.0	164	252	264	90	84	61	4.0
2		40	854.6	1.7	2.8	167	250	262	94	84	58	4.0
3	1058	45	859.066	1.4	2.3	167	251	252	94	85	58	3.5
	1101		859.066									
A-1		50	863.7	1.7	2.8	164	250	259	91	85	59	4.0
2		55	868.3	1.6	2.6	167	251	258	92	85	57	5.0
3	1116	60	872.525	1.3	2.1	167	251	260	93	86	56	4.5

COMMENTS: (CORRECT VOLUME)

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/9/05
SAMPLING TIME: (24 HR CLOCK) 1007 - 1116
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A / 26A AMB. TEMP (°F) 76
TECHNICIAN: Lee / Taylor

Run 3
26A

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok NA matrix
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	860.7	678.0	712.3	726.5			842.5	
INITIAL (ml)	738.0	641.6	705.5	724.8			833.7	
NET (ml)	122.7	36.4	6.8	1.7			8.8	176.4
TOTALS								176.4

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1166			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

Acid Mist

Catalyst Air Management, Inc.
Method 8 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **1** Date: 6/9/05 Start Time: 12:45
End Time: 13:57

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	132.6	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		872.867										
A-1	5.0	877.7	1.80	3.00	84	84	167				33.59	82.6
2	5.0	882.4	1.60	2.60	85	84	167	13.8	5.2	-1.10	31.67	77.8
3	5.0	886.514	1.30	2.10	87	84	167				28.55	70.2
		886.514										
B-1	5.0	891.8	1.80	3.00	88	85	164				33.51	82.4
2	5.0	896.6	1.70	2.80	92	86	168				32.67	80.3
3	5.0	900.796	1.40	2.30	94	86	168				29.65	72.9
		900.796										
C-1	5.0	905.7	1.80	3.00	93	87	165				33.54	82.4
2	5.0	910.6	1.80	3.00	95	87	168				33.62	82.6
3	5.0	915.232	1.50	2.50	96	88	168				30.69	75.4
		915.232										
D-1	5.0	920.2	1.80	3.00	94	88	164				33.51	82.4
2	5.0	925.0	1.70	2.80	96	89	167				32.65	80.2
3	5.0	929.452	1.40	2.30	97	89	168				29.65	72.9
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	56.585	1.276	2.700		89	167	13.8	5.2	-1.10	31.94	78.5
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.32	$V_{m(std)}$ =	53.806	$V_{w(std)}$ =	6.245	%M=	10.40
B_{ws} =	0.104	M_d =	30.42	M_s =	29.12	%EA=	32.13

STACK GAS VELOCITY =	78.5	AFPS	V_s
STACK GAS VELOCITY =	4,710	AFPM	
STACK GAS VOLUME =	615,600	DSCFM	Q_{std}
STACK GAS VOLUME =	832,267	ACFM	Q_a
ISOKINETIC RATIO =	100.3	%	

EMISSIONS

	Weight (mg)	Concentration (gr/dscf)	Fd Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
H2SO4	7.3	0.002	0.004	0.004

Catalyst Air Management, Inc.
Method 8 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **2** Date: 6/9/05 Start Time: 15:36
End Time: 16:45

DIAMETER OF NOZZLE:	0.217		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.57E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	157.1	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		943.607										
A-1	5.0	948.7	1.80	3.00	86	86	163				33.49	82.7
2	5.0	953.5	1.70	2.80	87	86	168	13.9	5.2	-1.10	32.67	80.7
3	5.0	958.008	1.40	2.30	89	86	168				29.65	73.2
		958.008										
B-1	5.0	962.9	1.80	3.00	90	87	166				33.57	82.9
2	5.0	967.7	1.70	2.80	93	87	168				32.67	80.7
3	5.0	972.153	1.40	2.30	94	88	167				29.63	73.1
		972.153										
C-1	5.0	977.0	1.80	3.00	94	88	165				33.54	82.8
2	5.0	981.9	1.70	2.80	96	89	168				32.67	80.7
3	5.0	986.277	1.40	2.30	98	89	168				29.65	73.2
		986.277										
D-1	5.0	990.6	1.70	2.80	96	90	166				32.62	80.5
2	5.0	994.3	1.60	2.60	97	90	168				31.70	78.2
3	5.0	997.678	1.30	2.10	98	90	167				28.55	70.5
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	54.071	1.266	2.650		91	167	13.9	5.2	-1.10	31.70	78.3
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.32	$V_{m(std)}$ =	51.269	$V_{w(std)}$ =	7.399	%M=	12.61
B_{ws} =	0.126	M_d =	30.43	M_s =	28.86	%EA=	32.18

STACK GAS VELOCITY =	78.3	AFPS	V_s
STACK GAS VELOCITY =	4,695	AFPM	
STACK GAS VOLUME =	598,455	DSCFM	Q_{std}
STACK GAS VOLUME =	829,679	ACFM	Q_a
ISOKINETIC RATIO =	98.3	%	

EMISSIONS	Weight (ug)	Concentration (ug/dscm)	Fd Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
H2SO4	7.7	0.002	0.004	0.004

Catalyst Air Management, Inc.
Method 8 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **3** Date: 6/9/05 Start Time: 17:36
End Time: 18:45

DIAMETER OF NOZZLE: 0.217
AREA OF NOZZLE: 2.57E-04 A_n
BAROMETRIC PRESSURE: 29.40 P_{bar}
GAS METER Y-FACTOR: 1.00 Y

STACK DIAMETER = 180 in
STACK AREA = 176.7 sq. ft.
VOLUME OF MOISTURE: 167.8 V_{lc}
PITOT COEFFICIENT: 0.84 C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		12.189										
A-1	5.0	16.9	1.70	2.80	90	90	163				32.54	80.4
2	5.0	21.6	1.60	2.60	91	90	167	13.9	5.3	-1.10	31.67	78.2
3	5.0	25.790	1.30	2.10	93	90	167				28.55	70.5
		25.790										
B-1	5.0	30.7	1.80	3.00	94	90	164				33.51	82.8
2	5.0	35.5	1.70	2.80	96	90	168				32.67	80.7
3	5.0	40.111	1.40	2.30	98	91	168				29.65	73.3
		40.111										
C-	5.0	45.0	1.80	3.00	96	91	164				33.51	82.8
2	5.0	49.9	1.70	2.80	98	91	168				32.67	80.7
3	5.0	54.389	1.40	2.30	100	92	168				29.65	73.3
		54.389										
D-1	5.0	58.7	1.80	3.00	98	92	164				33.51	82.8
2	5.0	63.5	1.60	2.60	99	92	168				31.70	78.3
3	5.0	68.228	1.40	2.30	100	92	167				29.63	73.2
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	56.039	1.263	2.633		94	166	13.9	5.3	-1.10	31.61	78.1
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s = 29.32 $V_{m(std)}$ = 52.853 $V_{w(std)}$ = 7.903 %M= 13.01
B_{ws} = 0.130 M_d = 30.44 M_s = 28.82 %EA= 33.06

STACK GAS VELOCITY = 78.1 AFPS V_s
STACK GAS VELOCITY = 4,685 AFPM
STACK GAS VOLUME = 594,915 DSCFM Q_{std}
STACK GAS VOLUME = 827,865 ACFM Q_a
ISOKINETIC RATIO = 101.9 %

EMISSIONS	Weight (ug)	Concentration (ug/dscm)	Fd Emission Rate (lb/mmBtu)	Fc Emission Rate (lb/mmBtu)
H2SO4	9.1	0.003	0.005	0.005

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	C 1167
Plant	SPURLOCK	Nozzle No.	55	Initial Leak (Samp.)	0.001 @ 11"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	ok @ 5"
Test	M-8	TC No.	CAM-05		ok @ 5"
Run	1	P_B	29.40		
Date	6-9-05	Ambient Temp	82	Final Leak (Samp.)	0.000 @ 6"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	ok @ 5"
Δ H	1.60 | Y_1 1.00				ok @ 7.5"

K = 1.64

POINT	TIME ACTUAL	RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1245		872.867					N/A				
A-1		5	877.7	1.8	3.0	167	242		84	84	63	3.0
2		10	882.4	1.6	2.6	167	240		85	84	60	2.5
3	1300	15	886.514	1.3	2.1	167	241		87	84	59	2.0
	1306		886.514									
B-1		20	891.8	1.8	3.0	164	238		88	85	60	3.0
2		25	896.6	1.7	2.8	168	238		92	86	54	3.0
3	1321	30	900.796	1.4	2.3	168	240		94	86	55	3.0
	1324		900.796									
C-1		35	905.7	1.8	3.0	165	238		93	87	58	3.0
2		40	910.6	1.8	3.0	168	238		95	87	56	3.0
3	1339	45	915.232	1.5	2.5	168	238		96	88	56	3.0
	1342		915.232									
D-1		50	920.2	1.8	3.0	164	238		94	88	58	3.5
2		55	925.0	1.7	2.8	167	237		96	89	58	3.0
3	1357	60	929.452	1.4	2.3	168	237		97	89	57	3.0

COMMENTS: PURGE 15 MIN. @ 2.5"

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/9/05
SAMPLING TIME: (24 HR CLOCK) 1245 - 1357
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A / 8 AMB. TEMP (°F) 82
TECHNICIAN: Love / Taylor

Run 1
Method 8

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.5		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.2	Fuel Type	Fo (calc)
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok NA volumetric
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER_____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	785.5	771.2	751.4				772.3	
INITIAL (ml)	729.4	735.9	722.6				759.9	
NET (ml)	56.1	35.3	28.8				12.4	132.6
TOTALS								132.6

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C 1167			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	C-1168
Plant	SPURLOCK	Nozzle No.	52	Initial Leak (Samp.)	0.000 @ 10"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @ 6"
Test	M-8	TC No.	CAM-5		OK @ 6"
Run	2	P_B	29.40		
Date	6-9-05	Ambient Temp	83	Final Leak (Samp.)	0.010 @ 5"
Meter Box	020	Static	-1.1	Final Leak (Pitot)	OK @ 5"
ΔH	1.60 | Y_I 1.00				OK @ 6"

K= 1.64

POINT	TIME ACTUAL	RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1536		943.607					N/A				
D-1		5	948.7	1.8	3.0	163	236		86	86	63	3.0
2		10	953.5	1.7	2.8	168	236		87	86	62	3.0
3	1551	15	958.008	1.4	2.3	168	236		89	86	65	2.5
	1554		958.008									
C-1		20	962.9	1.8	3.0	166	239		90	87	65	3.0
2		25	967.7	1.7	2.8	168	238		93	87	62	3.0
3	1609	30	972.153	1.4	2.3	167	238		94	88	63	2.5
	1612		972.153									
B-1		35	977.0	1.8	3.0	165	238		94	88	64	3.0
2		40	981.9	1.7	2.8	168	238		96	89	61	3.0
3	1627	45	986.277	1.4	2.3	168	237		98	89	61	2.5
	1630		986.277									
A-1		50	990.6	1.7	2.8	166	238		96	90	62	3.0
2		55	994.3	1.6	2.6	168	237		97	90	60	3.0
3	1645	60	997.678	1.3	2.1	167	238		98	90	61	2.5

COMMENTS: PURGE 15 MIN. @ 2.5"

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/9/05
SAMPLING TIME: (24 HR CLOCK) 1536 - 1645
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3A/B AMB. TEMP (°F) 83
TECHNICIAN: Taylor / Love

Run 2
Method 8

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok NA instrumental
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	758.7	732.3	726.1				824.3	
INITIAL (ml)	703.7	684.4	696.9				799.3	
NET (ml)	55.0	47.9	29.2				25.0	157.1
TOTALS								157.1

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1168			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM-107	Filter Number	C-1169
Plant	SPURLOCK	Nozzle No.	58	Initial Leak (Samp.)	0.000 @11"
Location	U-3 STACK	Nozzle Dn.	0.217	Initial Leak (Pitot)	OK @6"
Test	M-8	TC No.	CAM-5		OK @5"
Run	3	P_B	29.40		
Date	6-9-05	Ambient Temp	84	Final Leak (Samp.)	
Meter Box	020	Static	-1.1	Final Leak (Pitot)	
Δ H	1.60 | Y_i 1.00				

K = 1.64

POINT	TIME ACTUAL	RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1736		12.189					N/A				
A-1		5	16.9	1.7	2.8	163	236		90	90	63	3.0
2		10	21.6	1.6	2.6	167	236		91	90	64	2.5
3	1751	15	25.790	1.3	2.1	167	236		93	90	65	2.0
	1754		25.790									
B-1		20	30.7	1.8	3.0	164	235		94	90	65	3.0
2		25	35.5	1.7	2.8	168	238		96	90	64	3.0
3	1809	30	40.111	1.4	2.3	168	235		98	91	65	2.5
	1812		40.111									
C-1		35	45.0	1.8	3.0	164	238		96	91	65	3.0
2		40	49.9	1.7	2.8	168	236		98	91	61	3.0
3	1827	45	54.389	1.4	2.3	168	235		100	92	61	2.5
	1830		54.389									
D-1		50	58.7	1.8	3.0	164	235		98	92	64	3.0
2		55	63.5	1.6	2.6	168	236		99	92	59	3.0
3	1845	60	68.228	1.4	2.3	167	236		100	92	60	2.5

COMMENTS: PURGE 15 MIN, @ 2.5"

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/9/05
SAMPLING TIME: (24 HR CLOCK) 1736 - 1845
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Continuous
ANALYTICAL METHOD: 3a/8 AMB. TEMP (°F) 84
TECHNICIAN: Love / Taylor

Run 3
Method 8

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER _____ NA instrumental
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) _____/_____ BUBBLER_____

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	722.5	762.9	757.5				801.7	
INITIAL (ml)	696.1	719.9	727.2				783.6	
NET (ml)	76.4	43.0	30.3				18.1	167.8
TOTALS								167.8

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1169			WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

PROBE/NOZZLE WASH

BEAKER NO.				WEIGHED BY
FINAL WEIGHT				
INITIAL WEIGHT				
DIFFERENCE				
PARTICULATE CATCH				

TOTAL PARTICULATE CATCH (mg) _____

NOx/SO_2/CO/VOC

CATALYST AIR MANAGEMENT Inc.
CALIBRATION DATA

CLIENT: East Kentucky Power Cooperative
PLANT: Gilbert
UNIT: 3
TEST: NOx/CO/VOC/SO2
LOCATION: Stack

RUN #: 1-3
LOAD LEVEL: 295 MW
DATE: 6/13/2005

GAS UNITS	ANALYZER SCALE	CYLINDER VALUE	ANALYZER VALUE	DIFF PPM	% SPAN	Pass Yes\No
O2, %		0.00	0.03	0.03	0.12	**YES**
O2, %	**25**	12.47	12.47	0.00	0.00	**YES**
O2, %		22.63	22.59	0.04	0.16	**YES**
CO2, %		0.00	0.00	0.00	0.00	**YES**
CO2, %	**20**	9.85	9.79	0.06	0.30	**YES**
CO2, %		17.88	17.89	0.01	0.05	**YES**
NOx ppm:		0.0	0.07	0.07	0.07	**YES**
NOx ppm:	**100**	45.3	45.16	0.14	0.14	**YES**
NOx ppm:		88.4	88.72	0.32	0.32	**YES**
SO2 ppm:		0.0	0.00	0.00	0.00	**YES**
SO2 ppm:	**150**	79.35	80.4	1.05	1.05	**YES**
SO2 ppm:		125.0	125.6	0.60	0.60	**YES**
CO ppm		0.00	0.09	0.09	0.09	**YES**
CO ppm	**100**	30.43	30.4	0.03	0.03	**YES**
CO ppm		60.5	60.9	0.40	0.40	**YES**
CO ppm		89.0	88.8	0.20	0.20	**YES**
VOC ppm:		0.0	0.03	0.03	0.30	**YES**
VOC ppm:	**10**	2.92	3.01	0.09	0.90	**YES**
VOC ppm:		5.05	5.06	0.01	0.10	**YES**
VOC ppm:		8.94	8.99	0.05	0.50	**YES**

CATALYST AIR MANAGEMENT, Inc.
REFERENCE DATA

CLIENT: East Kentucky Power Cooperative
PLANT: Gilbert
UNIT: 3
TEST: 3A,7E,10,25A
LOCATION: Stack

RUN #: 1
OPERATING PARAMETER: 295 MW
START DATE: 6/13/2005
END DATE: 6/13/2005
START: 10:08
END: 11:08

DATE	TIME	O2	CO2	NOx	SO2	CO	VOC
6/13/2005	10:08	5.44	13.67	62.36	48.22	67.01	0.47
6/13/2005	10:09	5.41	13.69	62.07	48.74	66.82	0.22
6/13/2005	10:10	5.42	13.68	62.07	47.95	66.44	0.14
6/13/2005	10:11	5.44	13.67	61.4	41.85	66.42	0.86
6/13/2005	10:12	5.42	13.69	61.05	36.35	65.59	0.13
6/13/2005	10:13	5.43	13.65	61.62	40.97	65.61	1.36
6/13/2005	10:14	5.46	13.62	61.5	41.85	65.74	1.59
6/13/2005	10:15	5.43	13.65	60.58	46.42	66.06	2.55
6/13/2005	10:16	5.45	13.64	61.62	43.59	65.77	2.54
6/13/2005	10:17	5.49	13.62	62.21	36.8	66.58	2.71
6/13/2005	10:18	5.47	13.63	61.26	40.8	66.79	2.99
6/13/2005	10:19	5.47	13.61	61.95	44.67	67.27	0.56
6/13/2005	10:20	5.5	13.58	61.1	38.11	67.22	0.13
6/13/2005	10:21	5.48	13.57	60.35	35.98	67.58	0.88
6/13/2005	10:22	5.48	13.59	61.19	36.41	67.5	0.93
6/13/2005	10:23	5.48	13.59	60.3	42.51	67.01	0.15
6/13/2005	10:24	5.44	13.64	59.39	39.69	66	0.66
6/13/2005	10:25	5.46	13.6	58.77	52.72	66.15	0.8
6/13/2005	10:26	5.41	13.62	58.77	55.25	65.86	0.18
6/13/2005	10:27	5.42	13.62	58.23	63.28	66.23	0.79
6/13/2005	10:28	5.42	13.61	58.01	69.29	67.14	0.04
6/13/2005	10:29	5.42	13.61	58.43	63.8	66.84	0.26
6/13/2005	10:30	5.46	13.58	58.41	72.61	67.13	0.37
6/13/2005	10:31	5.42	13.63	57.77	64.28	66.78	0.89
6/13/2005	10:32	5.4	13.65	57.67	69.09	66.65	0.05
6/13/2005	10:33	5.38	13.63	57.36	64.06	65.94	0.6
6/13/2005	10:34	5.36	13.65	58.36	60.56	65.43	0.02
6/13/2005	10:35	5.47	13.56	59.71	54.21	65.1	0.94
6/13/2005	10:36	5.45	13.58	58.54	54.39	65.77	0.6
6/13/2005	10:37	5.45	13.62	57.39	50.06	66.26	1.24
6/13/2005	10:38	5.46	13.6	58.12	45.85	66.07	1.56
6/13/2005	10:39	5.51	13.54	59.05	46.76	65.9	0.84
6/13/2005	10:40	5.49	13.57	58.85	45.42	66.87	0.89
6/13/2005	10:41	5.47	13.56	58.51	50.85	66.5	1.26
6/13/2005	10:42	5.46	13.57	58.01	49.73	65.56	1.54
6/13/2005	10:43	5.48	13.55	58.66	50.93	64.71	1.2
6/13/2005	10:44	5.51	13.54	58.53	46.69	65.07	0.49
6/13/2005	10:45	5.5	13.56	58.19	47.04	65.11	0.31
6/13/2005	10:46	5.5	13.54	58.47	43.71	64.54	1.64
6/13/2005	10:47	5.54	13.52	58.74	41.58	65.09	2.66
6/13/2005	10:48	5.54	13.51	58.91	38.35	64.8	3.33
6/13/2005	10:49	5.54	13.5	59.5	40.86	64.54	1.8
6/13/2005	10:50	5.58	13.45	59.31	40.75	64.49	0.26
6/13/2005	10:51	5.5	13.46	57.83	46.12	64.15	0.67
6/13/2005	10:52	5.46	13.49	57.22	57.08	64.4	0.95
6/13/2005	10:53	5.44	13.5	55.43	68.21	63.6	0.14
6/13/2005	10:54	5.39	13.53	55.05	69.5	63.18	0.68
6/13/2005	10:55	5.44	13.54	55.55	62.15	62.89	0.05
6/13/2005	10:56	5.42	13.54	55.98	71.68	63.5	0.5
6/13/2005	10:57	5.45	13.52	55.86	64.69	63	0.79
6/13/2005	10:58	5.52	13.48	57.62	68.96	63.06	1.4
6/13/2005	10:59	5.47	13.48	56.52	68.89	63	0.81
6/13/2005	11:00	5.45	13.5	55.79	66.95	63.04	0.57
6/13/2005	11:01	5.42	13.51	55.08	66.68	62.8	0.18
6/13/2005	11:02	5.48	13.47	55.86	75.48	63.64	0.57
6/13/2005	11:03	5.52	13.47	55.81	78.06	64.22	0.27
6/13/2005	11:04	5.54	13.45	55.48	64.5	63.9	0.95
6/13/2005	11:05	5.55	13.46	54.78	72.34	63.91	0.69
6/13/2005	11:06	5.53	13.48	54.41	70.02	64.72	0.22
6/13/2005	11:07	5.5	13.5	54.02	80.71	64.96	0.3
6/13/2005	11:08	5.5	13.48	54.04	78.32	64.83	0.29
		O2	CO2	NOx	SO2	CO	VOC
		5.47	13.57	58.44	54.48	65.39	0.88
		%	%	ppm	ppm	ppm	ppm

Analyzer Readings not corrected

SYSTEM CALIBRATION BIAS AND DRIFT DATA

GAS UNITS	ANALYZER VALUE	PRE-TEST CHECK	% SPAN	Pass YES\NO	POST-TEST CHECK	% SPAN	% DRIFT	Pass YES\NO
O2, %	0.03	0.01	0.08	YES	0.00	0.12	0.04	YES
O2, %	12.47	12.45	0.08	YES	12.38	0.36	0.28	YES
CO2, %	0.00	0.05	0.25	YES	0.11	0.55	0.30	YES
CO2, %	9.79	9.71	0.40	YES	9.92	0.65	1.05	YES
NOx ppm:	0.07	0.24	0.17	YES	0.12	0.05	0.12	YES
NOx ppm:	45.16	45.28	0.12	YES	45.44	0.28	0.16	YES
SO2 ppm:	0.00	0.34	0.23	YES	1.40	0.93	0.71	YES
SO2 ppm:	125.60	125.50	0.07	YES	127.01	0.94	1.01	YES
CO ppm	0.09	0.07	0.02	YES	0.66	0.57	0.59	YES
CO ppm	30.40	29.90	0.50	YES	29.92	0.48	0.02	YES
VOC ppm:	0.03	0.03	0.00	YES	0.10	0.70	0.70	YES
VOC ppm:	3.01	3.01	0.00	YES	2.99	0.20	0.20	YES

UNCORRECTED ANALYZER VALUES

	DRY	WET
O2, %	5.5	
CO2, %	13.6	
NOx ppm:	58.4	
SO2 ppm:	54.5	
CO ppm:	65.4	
VOC ppm:		0.9

ANALYZER VALUES CORRECTED FOR DRIFT

	DRY
O2, %	5.5
CO2, %	13.6
NOx ppm:	58.4
SO2 ppm:	53.4
CO ppm:	67.0
VOC ppm:	1.0

F-Factor - Fd	9780
F-Factor - Fw	10640

EMISSION RATES

NOx, lbs/mmBtu =	0.093	CO, lbs/mmBtu =	0.065
SO2, lbs/mmBtu =	0.118	VOC, lbs/mmBtu =	0.001

CATALYST AIR MANAGEMENT, Inc.
REFERENCE DATA

CLIENT: East Kentucky Power Cooperative
PLANT: Gilbert
UNIT: 3
TEST: 3A,7E,10,25A
LOCATION: Stack

RUN #: 2
OPERATING PARAMETER: 295 MW
START DATE: 6/13/2005
END DATE: 6/13/2005
START: 11:23
END: 12:23

DATE	TIME	O2	CO2	NOx	SO2	CO	VOC
6/13/2005	11:23	5.36	13.64	52.94	91.78	63.9	0.93
6/13/2005	11:24	5.37	13.63	53.02	103.03	63.16	0.03
6/13/2005	11:25	5.32	13.67	53.02	99.16	62.72	0.39
6/13/2005	11:26	5.33	13.67	53.71	93.18	62.45	0.62
6/13/2005	11:27	5.29	13.69	53.93	95.56	62.1	0.5
6/13/2005	11:28	5.28	13.7	54.13	99.99	61.95	0.08
6/13/2005	11:29	5.3	13.68	54.18	93.53	62.43	0.08
6/13/2005	11:30	5.32	13.67	55.02	86.57	63.09	0.44
6/13/2005	11:31	5.33	13.67	55.43	92.45	62.98	0.69
6/13/2005	11:32	5.4	13.61	56.26	86.57	62.95	1.88
6/13/2005	11:33	5.38	13.63	55.45	78.46	62.88	1.34
6/13/2005	11:34	5.36	13.65	55.77	74.46	62.94	3.34
6/13/2005	11:35	5.36	13.66	56.23	69.98	62.83	2.59
6/13/2005	11:36	5.35	13.67	55.54	74.22	62.88	1.46
6/13/2005	11:37	5.42	13.63	56.57	74.54	63.54	2.17
6/13/2005	11:38	5.43	13.62	57.25	61.68	63.08	0.48
6/13/2005	11:39	5.42	13.63	56.91	64.51	63.03	0.17
6/13/2005	11:40	5.47	13.58	57.44	58.4	63.03	0.98
6/13/2005	11:41	5.45	13.56	57.66	55.79	62.62	1.44
6/13/2005	11:42	5.42	13.58	56.33	60.62	62.63	2.05
6/13/2005	11:43	5.38	13.61	56.03	61.21	63.27	1.84
6/13/2005	11:44	5.46	13.55	57.25	64.79	63.66	1.07
6/13/2005	11:45	5.41	13.35	55.99	57.94	62.11	1.52
6/13/2005	11:46	5.49	13.51	56.91	56.14	62.84	0.55
6/13/2005	11:47	5.47	13.54	56.68	55.26	63.03	0.08
6/13/2005	11:48	5.46	13.53	56.43	62.99	62.89	0.99
6/13/2005	11:49	5.44	13.56	55.75	63.62	62.93	0.35
6/13/2005	11:50	5.46	13.54	56.52	71.2	63.45	0.17
6/13/2005	11:51	5.49	13.51	56.47	63.03	63.63	1.2
6/13/2005	11:52	5.5	13.51	55.69	68.08	63.63	1.07
6/13/2005	11:53	5.53	13.53	55.38	66.79	63.77	1.47
6/13/2005	11:54	5.5	13.54	55.18	80.73	63.7	0.51
6/13/2005	11:55	5.48	13.56	54.68	78.01	63.3	0.04
6/13/2005	11:56	5.49	13.54	54.72	71.41	63.24	0.28
6/13/2005	11:57	5.53	13.5	56.23	80.08	63.02	0.18
6/13/2005	11:58	5.47	13.54	55.71	69.87	62.39	0.53
6/13/2005	11:59	5.49	13.54	56.29	78.26	63.07	0.46
6/13/2005	12:00	5.46	13.55	55.56	75.03	62.99	0.73
6/13/2005	12:01	5.5	13.52	56.19	74.49	63.02	0.07
6/13/2005	12:02	5.43	13.57	54.83	79.74	62.86	0.98
6/13/2005	12:03	5.47	13.55	54.98	77.49	63.21	0.96
6/13/2005	12:04	5.44	13.58	54.72	80.31	63.06	0.81
6/13/2005	12:05	5.38	13.58	54.72	87.96	62.27	0.38
6/13/2005	12:06	5.37	13.59	54.77	95.99	62.03	0.56
6/13/2005	12:07	5.36	13.6	54.39	95.31	61.95	0.92
6/13/2005	12:08	5.33	13.63	54.43	95.62	61.93	0.44
6/13/2005	12:09	5.39	13.59	54.82	88.07	61.66	0.63
6/13/2005	12:10	5.4	13.59	54.24	100.43	61.22	0.59
6/13/2005	12:11	5.35	13.6	54.26	104.37	60.86	0.79
6/13/2005	12:12	5.3	13.67	53.6	94.65	60.97	0.74
6/13/2005	12:13	5.29	13.68	54.06	110.48	60.27	0.96
6/13/2005	12:14	5.31	13.69	53.68	113.79	59.99	0.34
6/13/2005	12:15	5.3	13.71	54.53	92.58	59.84	0.18
6/13/2005	12:16	5.28	13.73	54.53	89.65	59.97	0.19
6/13/2005	12:17	5.31	13.76	54.7	77.82	60.08	0.28
6/13/2005	12:18	5.34	13.74	55.6	70.88	61.04	0.57
6/13/2005	12:19	5.36	13.71	56.06	63.28	60.89	0.51
6/13/2005	12:20	5.36	13.69	55.91	70.27	60.63	2
6/13/2005	12:21	5.35	13.71	56.27	69.27	60.5	1.7
6/13/2005	12:22	5.4	13.67	56.73	64.23	59.79	0.11
6/13/2005	12:23	5.34	13.72	55.91	58.53	59.82	0.25
		O2	CO2	NOx	SO2	CO	VOC
		5.40	13.61	55.38	78.59	62.33	0.81
		%	%	ppm	ppm	ppm	ppm

Analyzer Readings not corrected

SYSTEM CALIBRATION BIAS AND DRIFT DATA

GAS UNITS	ANALYZER VALUE	PRE-TEST CHECK	% SPAN	Pass YES\NO	POST-TEST CHECK	% SPAN	% DRIFT	Pass YES\NO
O2, %	0.03	0.00	0.12	YES	0.11	0.32	0.44	YES
O2, %	12.47	12.38	0.36	YES	12.32	0.60	0.24	YES
CO2, %	0.00	0.11	0.55	YES	0.15	0.75	0.20	YES
CO2, %	9.79	9.92	0.65	YES	9.86	0.35	0.30	YES
NOx ppm:	0.07	0.12	0.05	YES	0.08	0.01	0.04	YES
NOx ppm:	45.16	45.44	0.28	YES	45.06	0.10	0.38	YES
SO2 ppm:	0.00	1.40	0.93	YES	1.10	0.73	0.20	YES
SO2 ppm:	125.60	127.01	0.94	YES	126.00	0.27	0.67	YES
CO ppm	0.09	0.66	0.57	YES	0.55	0.46	0.11	YES
CO ppm	30.40	29.92	0.48	YES	29.92	0.48	0.00	YES
VOC ppm:	0.03	0.10	0.70	YES	0.02	0.10	0.80	YES
VOC ppm:	3.01	2.99	0.20	YES	3.02	0.10	0.30	YES

UNCORRECTED ANALYZER VALUES

	DRY	WET
O2, %	5.4	
CO2, %	13.6	
NOx ppm:	55.4	
SO2 ppm:	78.6	
CO ppm:	62.3	
VOC ppm:		0.8

ANALYZER VALUES CORRECTED FOR DRIFT

	DRY
O2, %	5.4
CO2, %	13.6
NOx ppm:	55.5
SO2 ppm:	77.2
CO ppm:	64.1
VOC ppm:	0.9

F-Factor	9780
F-Factor - Fw	10640

EMISSION RATES

NOx, lbs/mmBtu =	0.087	CO, lbs/mmBtu =	0.061
SO2, lbs/mmBtu =	0.169	VOC, lbs/mmBtu =	0.001

CATALYST AIR MANAGEMENT, Inc.
REFERENCE DATA

CLIENT: East Kentucky Power Cooperative
PLANT: Gilbert
UNIT: 3
TEST: 3A,7E,10,25A
LOCATION: Stack

RUN #: 3
OPERATING PARAMETER: 295 MW
START DATE: 6/13/2005
END DATE: 6/13/2005
START: 12:35
END: 13:35

DATE	TIME	O2	CO2	NOx	SO2	CO	VOC
6/13/2005	12:35	5.46	13.61	56.38	65.43	61.13	1.47
6/13/2005	12:36	5.43	13.66	55.24	59.87	60.99	2.15
6/13/2005	12:37	5.38	13.68	55.86	61.67	59.69	1.18
6/13/2005	12:38	5.35	13.71	55.35	56.95	59.65	0.65
6/13/2005	12:39	5.34	13.69	55.51	63.29	59.39	0.13
6/13/2005	12:40	5.38	13.66	56.02	61.67	59.48	0.29
6/13/2005	12:41	5.42	13.64	54.96	61.48	59.93	0.1
6/13/2005	12:42	5.45	13.48	54.85	85.3	60.27	0.5
6/13/2005	12:43	5.34	13.42	54.11	140.05	59.95	0.92
6/13/2005	12:44	5.25	13.47	53	147.67	59.8	1.06
6/13/2005	12:45	5.21	13.52	52.48	148.69	60.33	0.89
6/13/2005	12:46	5.13	13.54	51.77	148.61	59.45	0.35
6/13/2005	12:47	5.3	13.43	55.91	148.55	58.54	0.37
6/13/2005	12:48	5.32	13.42	56.68	148.52	57.96	0.65
6/13/2005	12:49	5.41	13.39	57.06	148.44	57.64	0.25
6/13/2005	12:50	5.45	13.31	57.43	148.14	57.68	1.09
6/13/2005	12:51	5.52	13.28	58.19	148.05	56.8	0.15
6/13/2005	12:52	5.64	13.19	58.64	146.42	56.7	0.1
6/13/2005	12:53	5.74	13.09	59.5	140.6	56.43	1.47
6/13/2005	12:54	5.87	12.99	60.92	121.39	56.59	1.82
6/13/2005	12:55	6.01	12.94	61.13	88.01	56.49	0.74
6/13/2005	12:56	6.06	12.91	60.38	69.77	56.27	0.26
6/13/2005	12:57	6.11	12.85	60.4	59.11	56.55	0.08
6/13/2005	12:58	6.14	12.84	59.39	54.04	55.82	0.22
6/13/2005	12:59	6.2	12.82	58.59	50.62	56.85	0.66
6/13/2005	13:00	6.17	12.88	56.97	54.19	56.78	0.53
6/13/2005	13:01	6.07	12.97	56.18	53.18	56.47	0.74
6/13/2005	13:02	6.03	13.01	55.97	58.5	56.49	0.65
6/13/2005	13:03	5.92	13.13	55.16	53.24	56.49	0.11
6/13/2005	13:04	5.85	13.22	54.82	64.29	56.99	0.08
6/13/2005	13:05	5.74	13.32	53.43	75.69	57.64	0.05
6/13/2005	13:06	5.66	13.39	53.21	78.97	57.84	0.5
6/13/2005	13:07	5.56	13.44	52.64	89.2	57.97	0.34
6/13/2005	13:08	5.53	13.44	51.84	121.98	58.29	1.16
6/13/2005	13:09	5.45	13.5	52.5	147.69	58.52	1.55
6/13/2005	13:10	5.44	13.53	53.14	148.25	58.49	1.66
6/13/2005	13:11	5.46	13.54	52.87	142.2	58.45	0.67
6/13/2005	13:12	5.43	13.56	52.86	148.26	58.49	0.23
6/13/2005	13:13	5.42	13.56	52.81	148.26	58.47	0.1
6/13/2005	13:14	5.39	13.61	52.9	148.27	57.71	0.31
6/13/2005	13:15	5.34	13.68	51.91	148.24	58.67	0.54
6/13/2005	13:16	5.32	13.74	51.76	148.24	58.49	0.61
6/13/2005	13:17	5.3	13.81	52.17	145.44	58.63	0.88
6/13/2005	13:18	5.31	13.87	53.66	112.15	58.12	1.29
6/13/2005	13:19	5.33	13.85	55.62	96.15	58.08	0.9
6/13/2005	13:20	5.34	13.88	54.68	84.07	57.93	0.26
6/13/2005	13:21	5.32	13.92	55.29	64.51	58.57	0.22
6/13/2005	13:22	5.4	13.81	56.31	55.57	58.21	0.39
6/13/2005	13:23	5.52	13.7	57.71	45.21	58.93	0.53
6/13/2005	13:24	5.53	13.66	57.01	39.96	58.9	0.08
6/13/2005	13:25	5.5	13.65	56.79	39.22	58.76	0.09
6/13/2005	13:26	5.47	13.67	55.39	36.91	59.14	0.25
6/13/2005	13:27	5.51	13.66	56.2	38.06	59.01	0.43
6/13/2005	13:28	5.52	13.66	56.9	63.12	59.1	0.95
6/13/2005	13:29	5.52	13.62	56.89	119.94	59.25	1.28
6/13/2005	13:30	5.55	13.61	57.6	147.91	59.46	0.94
6/13/2005	13:31	5.52	13.61	57.6	148.28	59.52	0.06
6/13/2005	13:32	5.54	13.63	57.26	148.27	60.07	0.49
6/13/2005	13:33	5.61	13.65	57.87	148.31	60.66	1.8
6/13/2005	13:34	5.63	13.63	59.29	146.71	60.72	1.42
6/13/2005	13:35	5.65	13.67	59.21	145.74	60.58	0.14
		O2	CO2	NOx	SO2	CO	VOC
		5.55	13.47	55.81	102.07	58.46	0.65
		%	%	ppm	ppm	ppm	ppm

Analyzer Readings not corrected

SYSTEM CALIBRATION BIAS AND DRIFT DATA

GAS UNITS	ANALYZER VALUE	PRE-TEST CHECK	% SPAN	Pass YES\NO	POST-TEST CHECK	% SPAN	% DRIFT	Pass YES\NO
O2, %	0.03	0.11	0.32	YES	0.13	0.40	0.08	YES
O2, %	12.47	12.32	0.60	YES	12.31	0.64	0.04	YES
CO2, %	0.00	0.15	0.75	YES	0.16	0.80	0.05	YES
CO2, %	9.79	9.86	0.35	YES	9.95	0.80	0.45	YES
NOx ppm:	0.07	0.08	0.01	YES	0.00	0.07	0.08	YES
NOx ppm:	45.16	45.06	0.10	YES	46.23	1.07	1.17	YES
SO2 ppm:	0.00	1.10	0.73	YES	1.22	0.81	0.08	YES
SO2 ppm:	125.60	126.00	0.27	YES	125.94	0.23	0.04	YES
CO ppm	0.09	0.55	0.46	YES	0.84	0.75	0.29	YES
CO ppm	30.40	29.92	0.48	YES	29.85	0.55	0.07	YES
VOC ppm:	0.03	0.02	0.10	YES	0.09	0.60	0.70	YES
VOC ppm:	3.01	3.02	0.10	YES	3.01	0.00	0.10	YES

UNCORRECTED ANALYZER VALUES

	DRY	WET
O2, %	5.6	
CO2, %	13.5	
NOx ppm:	55.8	
SO2 ppm:	102.1	
CO ppm:	58.5	
VOC ppm:		0.7

ANALYZER VALUES CORRECTED FOR DRIFT

	DRY
O2, %	5.6
CO2, %	13.5
NOx ppm:	55.4
SO2 ppm:	101.1
CO ppm:	60.2
VOC ppm:	0.7

F-Factor - Fd	9780
F-Factor - Fw	10640

EMISSION RATES

NOx, lbs/mmBtu =	0.088	CO, lbs/mmBtu =	0.059
SO2, lbs/mmBtu =	0.224	VOC, lbs/mmBtu =	0.001

Run 1

Plant Name: EKSP

General Average Report

Reporting Period: 06/13/2005 to 06/13/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 06/13/05 13:41

Rolling Average Interval: 1

Date	Time	CO2 (PERCENT)	COPPM (PPM)	LOADMW (MW)	FLOWSCFH (SCFH)	NOXPPM (PPM)	NOX#/MM (LB/MMBTU)	SO2PPM (PPM)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)
06/13/05	10:08	12.2	55.9	300.4	4.275E+07	55.7	0.098	34.9	0.085	0.060
	10:09	12.2	55.9	299.6	4.272E+07	55.4	0.098	33.9	0.083	0.060
	10:10	12.2	55.2	299.2	4.261E+07	55.4	0.098	32.1	0.079	0.059
	10:11	12.2	56.2	297.1	4.261E+07	54.9	0.097	27.7	0.068	0.060
	10:12	12.2	55.9	295.5	4.270E+07	54.9	0.097	26.3	0.064	0.060
	10:13	12.2	54.9	294.6	4.257E+07	54.8	0.097	29.6	0.072	0.059
	10:14	12.2	55.6	294.2	4.249E+07	54.5	0.096	31.4	0.077	0.060
	10:15	12.2	55.8	294.5	4.251E+07	54.4	0.096	33.1	0.081	0.060
	10:16	12.2	56.5	294.5	4.249E+07	54.9	0.097	28.8	0.071	0.061
	10:17	12.2	56.4	295.2	4.258E+07	55.0	0.097	27.7	0.068	0.060
	10:18	12.2	56.1	296.0	4.271E+07	54.9	0.097	31.1	0.076	0.060
	10:19	12.1	55.6	296.4	4.282E+07	54.7	0.097	30.8	0.076	0.060
	10:20	12.1	56.3	296.5	4.283E+07	54.3	0.096	26.6	0.066	0.061
	10:21	12.1	56.6	296.1	4.271E+07	54.1	0.096	26.5	0.065	0.061
	10:22	12.1	55.8	296.4	4.254E+07	54.2	0.096	28.2	0.070	0.060
	10:23	12.1	54.7	295.8	4.252E+07	53.7	0.095	30.9	0.076	0.059
	10:24	12.1	55.1	295.7	4.246E+07	53.0	0.094	33.5	0.083	0.060
	10:25	12.1	55.0	295.0	4.230E+07	52.6	0.093	41.2	0.102	0.059
	10:26	12.1	55.6	295.3	4.218E+07	52.5	0.093	45.4	0.112	0.060
	10:27	12.1	55.9	295.3	4.217E+07	52.1	0.093	53.4	0.132	0.060
	10:28	12.1	55.7	295.3	4.226E+07	51.9	0.092	52.6	0.130	0.060
	10:29	12.1	56.8	296.0	4.228E+07	52.1	0.093	54.5	0.135	0.061
	10:30	12.1	56.4	296.8	4.235E+07	52.1	0.093	54.3	0.134	0.061
	10:31	12.1	56.7	297.2	4.232E+07	51.6	0.092	52.4	0.129	0.061
	10:32	12.1	56.7	297.6	4.212E+07	51.5	0.091	52.6	0.130	0.061
	10:33	12.1	55.8	298.0	4.209E+07	51.6	0.092	49.6	0.122	0.060
	10:34	12.1	56.1	298.0	4.214E+07	52.2	0.093	44.9	0.111	0.061
	10:35	12.1	55.4	297.3	4.221E+07	52.8	0.094	41.7	0.103	0.060
	10:36	12.1	56.5	296.9	4.243E+07	52.1	0.093	40.2	0.099	0.061
	10:37	12.1	56.3	296.5	4.250E+07	51.5	0.091	36.4	0.090	0.061
	10:38	12.1	56.1	295.4	4.235E+07	52.2	0.093	35.5	0.088	0.061
	10:39	12.1	56.4	294.6	4.225E+07	52.6	0.093	34.8	0.086	0.061
	10:40	12.1	56.9	295.2	4.219E+07	52.5	0.093	37.0	0.091	0.062
	10:41	12.1	56.8	295.3	4.238E+07	52.3	0.093	39.0	0.096	0.061
	10:42	12.1	57.0	296.4	4.256E+07	52.1	0.093	38.7	0.096	0.062
	10:43	12.1	55.8	296.8	4.239E+07	52.3	0.093	37.2	0.092	0.060
	10:44	12.1	55.8	296.5	4.238E+07	52.2	0.093	34.4	0.085	0.060
	10:45	12.1	56.4	296.5	4.262E+07	52.0	0.092	33.7	0.083	0.061
	10:46	12.1	55.0	296.5	4.268E+07	52.3	0.093	30.2	0.075	0.059
	10:47	12.0	54.3	296.1	4.274E+07	52.3	0.094	29.3	0.073	0.059
	10:48	12.0	54.5	296.1	4.282E+07	52.7	0.094	28.0	0.070	0.059
	10:49	12.0	54.7	295.8	4.260E+07	52.9	0.095	29.9	0.074	0.060
	10:50	12.0	53.8	296.0	4.241E+07	52.5	0.094	30.7	0.076	0.059
	10:51	12.0	54.5	296.1	4.227E+07	51.8	0.093	38.1	0.095	0.059
	10:52	12.0	53.4	296.1	4.204E+07	51.0	0.091	48.2	0.120	0.058
	10:53	12.0	53.1	296.1	4.192E+07	49.8	0.089	53.6	0.133	0.058
	10:54	12.0	53.3	296.1	4.200E+07	49.4	0.088	52.7	0.131	0.058
	10:55	12.0	52.6	296.1	4.216E+07	49.7	0.089	53.0	0.132	0.057
	10:56	12.0	52.9	295.8	4.223E+07	50.0	0.090	53.6	0.133	0.058
	10:57	12.0	52.7	295.0	4.221E+07	50.4	0.090	55.1	0.137	0.057

Plant Name: EKSP

General Average Report

Reporting Period: 06/13/2005 to 06/13/2005

Site Name: UNIT03

Time of Report: 06/13/05 13:41

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	CO2 (PERCENT)	COPPM (PPM)	LOADMW (MW)	FLOWSCFH (SCFH)	NOXPPM (PPM)	NOX#/MM (LB/MMBTU)	SO2PPM (PPM)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)
06/13/05	10:58	12.0	53.1	294.6	4.219E+07	51.0	0.091	53.7	0.134	0.058
	10:59	12.0	53.8	294.2	4.217E+07	50.5	0.090	54.1	0.135	0.059
	11:00	12.0	53.5	294.5	4.203E+07	49.9	0.089	52.4	0.130	0.058
	11:01	12.0	53.0	294.2	4.197E+07	49.8	0.089	55.4	0.138	0.058
	11:02	12.0	53.7	293.8	4.198E+07	50.0	0.090	62.3	0.155	0.059
	11:03	12.0	54.7	293.4	4.197E+07	49.9	0.089	55.9	0.139	0.060
	11:04	12.0	53.5	293.4	4.195E+07	49.6	0.089	53.7	0.134	0.058
	11:05	12.0	55.2	293.4	4.193E+07	49.2	0.088	54.9	0.137	0.060
	11:06	12.0	53.9	293.4	4.195E+07	48.7	0.087	57.3	0.143	0.059
	11:07	12.0	56.1	294.1	4.196E+07	48.6	0.087	63.2	0.157	0.061
	11:08	12.0	55.7	294.2	4.193E+07	48.6	0.087	57.4	0.143	0.061
Average =		12.1	55.2	295.8	4.235E+07	52.2	0.093	41.7	0.103	0.060
Maximum =		12.2	57.0	300.4	4.283E+07	55.7	0.098	63.2	0.157	0.062
Minimum =		12.0	52.6	293.4	4.192E+07	48.6	0.087	26.3	0.064	0.057
Possible Values =		61	61	61	61	61	61	61	61	61
Included Values =		61	61	61	61	61	61	61	61	61
Total =		737.0	3369.9	18044.8	2.583E+09	3184.5	5.663	2545.4	6.301	3.648

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
- suspect
- exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

Run 2

Plant Name: EKSP

General Average Report

Reporting Period: 06/13/2005 to 06/13/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 06/13/05 13:42

Rolling Average Interval: 1

Date	Time	CO2 (PERCENT)	COPPM (PPM)	LOADMW (MW)	FLOWSCFH (SCFH)	NOXPPM (PPM)	NOX#/MM (LB/MMBTU)	SO2PPM (PPM)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)
06/13/05	11:23	12.2	53.1	295.4	4.177E+07	47.7	0.084	73.8	0.181	0.057
	11:24	12.2	53.2	295.6	4.178E+07	47.9	0.084	79.9	0.196	0.057
	11:25	12.2	53.5	295.7	4.173E+07	47.8	0.084	79.5	0.195	0.057
	11:26	12.2	52.2	296.1	4.174E+07	48.2	0.085	75.2	0.184	0.056
	11:27	12.2	52.1	295.8	4.176E+07	48.6	0.086	74.5	0.182	0.056
	11:28	12.2	52.5	295.4	4.176E+07	48.5	0.085	76.9	0.188	0.056
	11:29	12.2	53.3	295.6	4.185E+07	48.8	0.086	73.4	0.180	0.057
	11:30	12.2	53.3	295.7	4.205E+07	49.3	0.087	68.9	0.169	0.057
	11:31	12.2	53.7	295.4	4.206E+07	49.6	0.087	69.1	0.169	0.058
	11:32	12.2	53.3	295.3	4.197E+07	50.3	0.089	67.9	0.166	0.057
	11:33	12.2	52.6	294.6	4.197E+07	50.2	0.088	62.6	0.153	0.056
	11:34	12.2	53.0	294.5	4.198E+07	50.1	0.088	57.8	0.142	0.057
	11:35	12.2	53.1	294.2	4.202E+07	50.4	0.089	54.0	0.132	0.057
	11:36	12.2	53.7	294.2	4.202E+07	50.2	0.088	54.9	0.134	0.058
	11:37	12.2	53.4	294.1	4.209E+07	50.3	0.089	55.4	0.136	0.057
	11:38	12.1	53.2	294.8	4.225E+07	51.0	0.091	49.6	0.122	0.058
	11:39	12.2	52.7	294.6	4.226E+07	51.2	0.090	47.8	0.117	0.057
	11:40	12.1	52.2	294.5	4.219E+07	51.6	0.092	44.9	0.111	0.056
	11:41	12.1	52.8	294.5	4.208E+07	51.6	0.092	42.1	0.104	0.057
	11:42	12.1	52.3	294.2	4.193E+07	51.2	0.091	43.4	0.107	0.057
	11:43	12.1	53.6	294.2	4.192E+07	50.5	0.090	44.6	0.110	0.058
	11:44	12.1	53.9	293.8	4.207E+07	51.0	0.091	47.6	0.118	0.058
	11:45	12.1	52.7	293.4	4.214E+07	50.7	0.090	44.7	0.110	0.057
	11:46	12.1	52.3	293.1	4.222E+07	51.0	0.091	41.5	0.102	0.057
	11:47	12.1	53.3	293.0	4.222E+07	50.9	0.090	40.9	0.101	0.058
	11:48	12.1	53.1	293.3	4.211E+07	50.9	0.090	44.7	0.110	0.057
	11:49	12.1	52.9	293.4	4.209E+07	50.6	0.090	47.8	0.118	0.057
	11:50	12.1	52.2	293.4	4.216E+07	50.5	0.090	52.8	0.130	0.056
	11:51	12.1	52.9	293.7	4.224E+07	50.8	0.090	50.0	0.123	0.057
	11:52	12.0	52.9	293.8	4.225E+07	50.4	0.090	51.3	0.128	0.058
	11:53	12.0	53.0	295.1	4.216E+07	50.2	0.090	52.1	0.130	0.058
	11:54	12.0	52.9	295.3	4.206E+07	49.7	0.089	58.6	0.146	0.058
	11:55	12.1	52.6	295.0	4.226E+07	49.5	0.088	61.1	0.151	0.057
	11:56	12.1	52.1	295.3	4.239E+07	49.4	0.088	56.8	0.140	0.056
	11:57	12.0	52.9	296.0	4.227E+07	49.9	0.089	59.6	0.148	0.058
	11:58	12.0	52.1	296.1	4.220E+07	50.3	0.090	55.9	0.139	0.057
	11:59	12.0	52.3	296.4	4.220E+07	50.5	0.090	59.0	0.147	0.057
	12:00	12.0	52.7	296.1	4.221E+07	50.4	0.090	59.2	0.147	0.057
	12:01	12.0	52.1	296.4	4.225E+07	50.4	0.090	58.2	0.145	0.057
	12:02	12.1	52.2	296.5	4.221E+07	49.9	0.089	60.3	0.149	0.056
	12:03	12.1	52.2	296.8	4.207E+07	49.6	0.088	61.1	0.151	0.056
	12:04	12.1	53.3	296.5	4.211E+07	49.6	0.088	62.9	0.155	0.058
	12:05	12.1	52.1	297.1	4.221E+07	49.5	0.088	68.5	0.169	0.056
	12:06	12.1	52.1	297.3	4.224E+07	49.5	0.088	74.5	0.184	0.056
	12:07	12.1	52.8	297.6	4.221E+07	49.2	0.087	74.8	0.185	0.057
	12:08	12.1	53.0	297.3	4.220E+07	49.1	0.087	75.9	0.187	0.057
	12:09	12.1	50.7	297.3	4.233E+07	49.3	0.088	72.4	0.179	0.055
	12:10	12.1	51.6	296.9	4.233E+07	49.2	0.087	76.9	0.190	0.056
	12:11	12.1	50.6	296.9	4.225E+07	49.0	0.087	81.8	0.202	0.055
	12:12	12.2	50.3	296.9	4.225E+07	48.7	0.086	78.5	0.192	0.054

Plant Name: EKSP

General Average Report

Reporting Period: 06/13/2005 to 06/13/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 06/13/05 13:42

Rolling Average Interval: 1

Date	Time	CO2 (PERCENT)	COPPM (PPM)	LOADMW (MW)	FLOWSCFH (SCFH)	NOXPPM (PPM)	NOX#/MM (LB/MMBTU)	SO2PPM (PPM)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)
06/13/05	12:13	12.2	49.6	296.9	4.224E+07	48.7	0.086	85.4	0.209	0.053
	12:14	12.2	49.8	296.9	4.228E+07	48.6	0.086	89.1	0.218	0.053
	12:15	12.2	50.3	296.9	4.232E+07	49.0	0.086	79.0	0.193	0.054
	12:16	12.2	49.6	296.2	4.242E+07	49.1	0.086	71.1	0.174	0.053
	12:17	12.2	49.2	295.8	4.255E+07	49.4	0.087	62.4	0.153	0.053
	12:18	12.3	49.8	295.7	4.261E+07	49.7	0.087	55.7	0.135	0.053
	12:19	12.2	50.6	295.7	4.262E+07	50.4	0.089	50.0	0.122	0.054
	12:20	12.2	51.2	295.7	4.253E+07	50.3	0.089	51.0	0.125	0.055
	12:21	12.2	50.6	295.7	4.249E+07	50.6	0.089	51.2	0.125	0.054
	12:22	12.2	50.1	295.4	4.255E+07	51.0	0.090	48.5	0.119	0.054
	12:23	12.2	49.8	295.3	4.255E+07	50.7	0.089	45.2	0.111	0.053
Average =		12.1	52.2	295.4	4.217E+07	49.9	0.088	60.9	0.150	0.056
Maximum =		12.3	53.9	297.6	4.262E+07	51.6	0.092	89.1	0.218	0.058
Minimum =		12.0	49.2	293.0	4.173E+07	47.7	0.084	40.9	0.101	0.053
Possible Values =		61	61	61	61	61	61	61	61	61
Included Values =		61	61	61	61	61	61	61	61	61
Total =		739.9	3183.2	18020.1	2.572E+09	3041.9	5.389	3714.2	9.143	3.432

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
- suspect
- exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

Run 3

Plant Name: EKSP

General Average Report

Reporting Period: 06/13/2005 to 06/13/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 06/13/05 13:43

Rolling Average Interval: 1

Date	Time	CO2 (PERCENT)	COPPM (PPM)	LOADMW (MW)	FLOWSCFH (SCFH)	NOXPPM (PPM)	NOX#/MM (LB/MMBTU)	SO2PPM (PPM)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)
06/13/05	12:35	12.1	50.6	295.6	4.224E+07	50.8	0.090	49.5	0.122	0.055
	12:36	12.1	50.7	295.7	4.227E+07	50.5	0.090	47.8	0.118	0.055
	12:37	12.2	49.8	296.0	4.237E+07	50.3	0.089	46.7	0.114	0.053
	12:38	12.2	50.1	296.4	4.238E+07	50.1	0.088	43.8	0.107	0.054
	12:39	12.2	50.9	296.5	4.238E+07	50.1	0.088	47.3	0.116	0.055
	12:40	12.2	50.6	296.8	4.239E+07	50.4	0.089	47.2	0.116	0.054
	12:41	12.2	50.0	297.9	4.220E+07	50.0	0.088	46.9	0.115	0.054
	12:42	12.1	50.0	298.7	4.188E+07	49.7	0.088	63.6	0.157	0.054
	12:43	12.0	50.3	299.1	4.153E+07	49.4	0.088	99.7	0.248	0.055
	12:44	12.0	49.6	299.2	4.132E+07	48.5	0.087	136.8	0.341	0.054
	12:45	12.0	50.8	299.2	4.169E+07	47.9	0.086	177.3	0.441	0.055
	12:46	12.0	48.4	299.2	4.217E+07	47.3	0.085	207.8	0.517	0.053
	12:47	12.0	48.8	299.2	4.221E+07	48.9	0.088	195.3	0.486	0.053
	12:48	12.0	47.5	298.8	4.214E+07	50.7	0.091	172.2	0.429	0.052
	12:49	11.9	47.4	297.8	4.201E+07	51.4	0.093	168.3	0.423	0.052
	12:50	11.9	46.9	297.0	4.163E+07	51.8	0.094	175.1	0.440	0.052
	12:51	11.8	46.6	295.9	4.116E+07	52.3	0.095	166.4	0.421	0.052
	12:52	11.7	46.8	294.7	4.083E+07	52.9	0.097	146.4	0.374	0.052
	12:53	11.6	47.3	292.9	4.059E+07	53.6	0.099	121.4	0.313	0.053
	12:54	11.6	46.7	290.9	4.030E+07	54.3	0.101	103.2	0.266	0.053
	12:55	11.5	47.0	288.7	3.997E+07	55.1	0.103	76.4	0.199	0.053
	12:56	11.4	47.5	286.0	3.968E+07	55.0	0.104	56.1	0.147	0.055
	12:57	11.4	47.0	284.0	3.947E+07	54.6	0.103	43.6	0.114	0.054
	12:58	11.3	46.8	281.7	3.954E+07	54.2	0.103	37.1	0.098	0.054
	12:59	11.3	46.7	280.1	3.962E+07	53.5	0.102	34.1	0.090	0.054
	13:00	11.3	47.5	279.2	3.963E+07	52.4	0.100	35.5	0.094	0.055
	13:01	11.4	48.1	278.8	3.978E+07	51.3	0.097	37.0	0.097	0.055
	13:02	11.4	48.1	278.7	4.017E+07	50.9	0.096	39.8	0.104	0.055
	13:03	11.5	48.1	279.1	4.067E+07	50.3	0.094	38.9	0.101	0.055
	13:04	11.6	47.5	279.8	4.117E+07	49.9	0.092	45.1	0.116	0.054
	13:05	11.7	48.9	280.9	4.168E+07	49.0	0.090	55.5	0.142	0.055
	13:06	11.8	48.0	280.4	4.199E+07	48.6	0.089	60.0	0.152	0.053
	13:07	11.9	48.5	281.1	4.214E+07	48.0	0.087	68.3	0.171	0.053
	13:08	11.9	48.1	288.6	4.227E+07	47.4	0.086	92.8	0.233	0.053
	13:09	11.9	48.8	292.2	4.248E+07	47.4	0.086	115.5	0.290	0.054
	13:10	12.0	49.2	294.0	4.246E+07	47.8	0.086	121.2	0.302	0.054
	13:11	12.0	48.5	294.2	4.223E+07	48.1	0.086	118.7	0.296	0.053
	13:12	12.0	48.4	293.6	4.234E+07	48.0	0.086	131.3	0.327	0.053
	13:13	12.1	48.0	292.8	4.243E+07	47.8	0.085	133.7	0.330	0.052
	13:14	12.1	48.0	292.3	4.237E+07	47.9	0.085	132.2	0.326	0.052
	13:15	12.1	49.0	291.7	4.241E+07	47.4	0.084	133.3	0.329	0.053
	13:16	12.1	48.5	291.5	4.261E+07	47.1	0.084	133.6	0.330	0.052
	13:17	12.2	47.1	291.7	4.274E+07	47.1	0.083	127.9	0.313	0.050
	13:18	12.3	48.0	291.9	4.270E+07	47.8	0.084	101.3	0.246	0.051
	13:19	12.3	47.9	291.9	4.269E+07	49.4	0.086	81.7	0.198	0.051
	13:20	12.3	47.9	292.1	4.276E+07	49.6	0.087	66.7	0.162	0.051
	13:21	12.3	47.7	292.3	4.299E+07	49.6	0.087	51.2	0.124	0.051
	13:22	12.3	48.3	292.3	4.314E+07	50.3	0.088	40.5	0.098	0.051
	13:23	12.3	48.7	292.2	4.305E+07	51.5	0.090	31.4	0.076	0.052
	13:24	12.2	49.0	292.6	4.295E+07	51.7	0.091	25.8	0.063	0.053

Plant Name: EKSP

General Average Report

Reporting Period: 06/13/2005 to 06/13/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 06/13/05 13:43

Rolling Average Interval: 1

Date	Time	CO2 (PERCENT)	COPPM (PPM)	LOADMW (MW)	FLOWSCFH (SCFH)	NOXPPM (PPM)	NOX#/MM (LB/MMBTU)	SO2PPM (PPM)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)
06/13/05	13:25	12.2	49.5	292.8	4.300E+07	51.5	0.091	24.1	0.059	0.053
	13:26	12.2	49.2	292.6	4.301E+07	50.8	0.089	23.3	0.057	0.053
	13:27	12.1	49.5	292.8	4.286E+07	50.7	0.090	24.7	0.061	0.054
	13:28	12.2	49.0	293.4	4.288E+07	51.4	0.091	42.6	0.104	0.053
	13:29	12.2	49.7	294.5	4.430E+07	52.0	0.092	82.1	0.201	0.053
	13:30	12.3	50.6	296.1	4.391E+07	52.6	0.092	118.1	0.287	0.054
	13:31	12.3	50.0	296.7	4.424E+07	52.6	0.092	128.0	0.311	0.053
	13:32	12.3	50.4	296.5	4.524E+07	52.7	0.092	143.4	0.348	0.054
	13:33	12.3	50.7	296.5	4.482E+07	52.8	0.092	152.1	0.369	0.054
	13:34	12.3	50.7	296.3	4.508E+07	53.4	0.093	135.5	0.329	0.054
	13:35	12.3	49.3	295.9	4.531E+07	53.2	0.093	107.3	0.261	0.052
Average =		12.0	48.7	291.9	4.214E+07	50.5	0.091	90.3	0.225	0.053
Maximum =		12.3	50.9	299.2	4.531E+07	55.1	0.104	207.8	0.517	0.055
Minimum =		11.3	46.6	278.7	3.947E+07	47.1	0.083	23.3	0.057	0.050
Possible Values =		61	61	61	61	61	61	61	61	61
Included Values =		61	61	61	61	61	61	61	61	61
Total =		730.0	2969.5	17807.6	2.570E+09	3083.2	5.540	5510.2	13.723	3.245

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
- suspect
- exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

APPENDIX 2

REFERENCE METHOD TEST RESULTS - PARTICULATE

Baseline

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **1** Date: 6/16/05 Start Time: 7:53
End Time: 9:01

DIAMETER OF NOZZLE:	0.196		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.10E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.44	P_{bar}	VOLUME OF MOISTURE:	121.2	V_{lc}
GAS METER Y-FACTOR:	1.005	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		129.365										
A-1	5.0	132.7	1.50	1.73	71	71	161				30.52	75.3
2	5.0	136.0	1.50	1.73	70	70	162	13.8	5.3	-0.86	30.55	75.3
3	5.0	139.320	1.40	1.61	70	70	162				29.51	72.8
		139.320										
B-1	5.0	142.7	1.50	1.73	72	72	163				30.57	75.4
2	5.0	146.0	1.50	1.73	72	72	166				30.64	75.6
3	5.0	149.200	1.10	1.27	73	73	168				26.28	64.8
		149.200										
C-1	5.0	152.6	1.50	1.73	74	74	172				30.79	75.9
2	5.0	155.9	1.50	1.73	74	74	176				30.89	76.2
3	5.0	159.310	1.50	1.73	75	75	181				31.01	76.5
		159.310										
D-1	5.0	162.6	1.50	1.73	76	76	179				30.96	76.4
2	5.0	166.2	1.60	1.84	76	76	177				31.92	78.7
3	5.0	169.625	1.50	1.73	77	77	177				30.91	76.2
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	40.260	1.210	1.691		73	170	13.8	5.3	-0.86	30.38	74.9
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.38	$V_{m(std)}$ =	39.565	$V_{w(std)}$ =	5.709	%M=	12.61
B_{ws} =	0.126	M_d =	30.42	M_s =	28.85	%EA=	33.01

STACK GAS VELOCITY =	74.9	AFPS	V_s
STACK GAS VELOCITY =	4,496	AFPM	
STACK GAS VOLUME =	570,988	DSCFM	Q_{std}
STACK GAS VOLUME =	794,428	ACFM	Q_a
ISOKINETIC RATIO =	97.4	%	

PARTICULATE EMISSIONS

Weight, mg =	6.9
GR/DSCF =	0.003
Fo LBS/MMBTU =	**0.005**
Fc LBS/MMBTU =	**0.005**

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **2** Date: 6/16/05 Start Time: 9:40
End Time: 10:44

DIAMETER OF NOZZLE:	0.196		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.10E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.44	P_{bar}	VOLUME OF MOISTURE:	125.8	V_{lc}
GAS METER Y-FACTOR:	1.005	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		170.593										
A-1	5.0	173.6	1.70	1.95	76	76	175				32.86	81.1
2	5.0	177.4	1.70	1.95	77	77	176	13.8	5.3	-0.86	32.88	81.2
3	5.0	181.999	1.50	1.73	78	78	178				30.94	76.4
		181.999										
B-1	5.0	184.5	1.50	1.73	78	78	184				31.08	76.8
2	5.0	188.0	1.50	1.73	78	78	185				31.10	76.8
3	5.0	191.450	1.10	1.27	79	79	184				26.62	65.7
		191.450										
C-1	5.0	194.8	1.50	1.73	79	79	183				31.06	76.7
2	5.0	198.0	1.50	1.73	79	79	182				31.03	76.6
3	5.0	201.050	1.10	1.27	79	79	181				26.55	65.6
		201.050										
D-1	5.0	204.5	1.50	1.73	79	79	180				30.98	76.5
2	5.0	208.0	1.50	1.73	79	79	180				30.98	76.5
3	5.0	210.789	0.85	0.98	80	80	178				23.29	57.5
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	40.196	1.183	1.628		78	181	13.8	5.3	-0.86	29.95	74.0
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.38	$V_{m(std)}$ =	39.123	$V_{w(std)}$ =	5.925	%M=	13.15
B_{ws} =	0.132	M_d =	30.42	M_s =	28.79	%EA=	33.01

STACK GAS VELOCITY =	74.0	AFPS	V_s
STACK GAS VELOCITY =	4,437	AFPM	
STACK GAS VOLUME =	551,138	DSCFM	Q_{std}
STACK GAS VOLUME =	784,059	ACFM	Q_a
ISOKINETIC RATIO =	99.8	%	

PARTICULATE EMISSIONS

Weight, mg =	5.4
GR/DSCF =	0.002
Fo LBS/MMBTU =	**0.004**
Fc LBS/MMBTU =	**0.004**

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Gilbert 3**
Sampling Location: Stack

Run No: **3** Date: 6/16/05 Start Time: 11:10
End Time: 12:17

DIAMETER OF NOZZLE:	0.196		STACK DIAMETER =	180	in
AREA OF NOZZLE:	2.10E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.44	P_{bar}	VOLUME OF MOISTURE:	126.1	V_{lc}
GAS METER Y-FACTOR:	1.005	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		211.018										
A-1	5.0	214.5	1.50	1.73	78	78	171				30.77	76.0
2	5.0	218.0	1.50	1.73	78	78	171	13.8	5.3	-0.90	30.77	76.0
3	5.0	221.250	0.95	1.09	79	79	170				24.46	60.4
		221.250										
B-1	5.0	224.8	1.50	1.73	79	79	171				30.77	76.0
2	5.0	228.2	1.50	1.73	80	80	171				30.77	76.0
3	5.0	231.590	1.10	1.27	80	80	172				26.37	65.1
		231.590										
C-	5.0	234.8	1.50	1.73	80	80	174				30.84	76.1
2	5.0	238.3	1.50	1.73	80	80	178				30.94	76.4
3	5.0	241.570	1.10	1.27	81	81	178				26.49	65.4
		241.570										
D-1	5.0	244.9	1.50	1.73	80	80	177				30.91	76.3
2	5.0	248.4	1.50	1.73	81	81	177				30.91	76.3
3	5.0	251.635	1.10	1.27	81	81	177				26.47	65.4
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	40.617	1.160	1.562		80	174	13.8	5.3	-0.90	29.20	72.1
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.37	$V_{m(std)}$ =	39.428	$V_{w(std)}$ =	5.939	%M=	13.09
B_{ws} =	0.131	M_d =	30.42	M_s =	28.79	%EA=	33.01

STACK GAS VELOCITY =	72.1	AFPS	V_s
STACK GAS VELOCITY =	4,327	AFPM	
STACK GAS VOLUME =	543,324	DSCFM	Q_{std}
STACK GAS VOLUME =	764,532	ACFM	Q_a
ISOKINETIC RATIO =	102.1	%	

PARTICULATE EMISSIONS

Weight, mg =	6.7
GR/DSCF =	0.003
Fo LBS/MMBTU =	**0.005**
Fc LBS/MMBTU =	**0.005**

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	07	Filter Number	~~032~~ 132
Plant	Spurlock	Nozzle No.	008	Initial Leak (Samp.)	0.000 @ 15"
Location	Unit 3	Nozzle Dn.	0.196	Initial Leak (Pitot)	∅ @ 3'
Test	PM	TC No.	004		∅ @ 3'
Run	1	P_B	29.44		
Date	6-16-05	Ambient Temp	75	Final Leak (Samp.)	0.000 @ 6'
Meter Box	093	Static	-0.86	Final Leak (Pitot)	∅ @ 2.8
Δ H	1.71 | Y_1 1.005				∅ @ 2.8

K = 1.15

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	0753		129.365									
A1		5	132.7	1.5	1.73	161	266	255	71	71	66	4.0
2		10	136.0	1.5	1.73	162	265	250	70	70	65	4.0
3		15	139.320	1.4	1.61	162	263	251	70	70	60	4.0
B1		20	142.7	1.5	1.73	163	241	253	72	72	66	4.0
2		25	146.0	1.5	1.73	166	240	252	72	72	60	4.0
3		30	149.200	1.1	1.27	168	239	251	73	73	56	4.0
C1		35	152.6	1.5	1.73	172	241	250	74	74	54	4.0
2		40	155.9	1.5	1.73	176	241	247	74	74	52	4.0
3		45	159.310	1.5	1.73	181	240	249	75	75	49	4.0
D1		50	162.6	1.5	1.73	179	240	253	76	76	51	4.0
2		55	166.2	1.6	1.84	177	241	247	76	76	47	4.0
3	0901	60	169.625	1.5	1.73	177	242	245	77	77	46	4.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/16/05
SAMPLING TIME: (24 HR CLOCK) 0753 - 0901
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 80
TECHNICIAN: Heiter / Williams

Run 1
PM

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.9		13.8		13.9		13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.3	19.1	5.3	19.1	5.3	5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.718

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.2 / 20.2 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 19.9 / 19.8 BUBBLER ok

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	805.1	767.5	604.1				934.3	
INITIAL (ml)	713.6	745.2	601.5				929.5	
NET (ml)	91.5	22.3	2.6				4.8	121.2
TOTALS								121.2

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	132		062	WEIGHED BY
			BLANK	
FINAL WEIGHT	0.2492		0.2569	MT
INITIAL WEIGHT	0.2490		0.2569	CH
DIFFERENCE	0.0002		↳	MT
PARTICULATE CATCH	0.2		↳	MT

PROBE/NOZZLE WASH

BEAKER NO.	14		Blank	WEIGHED BY
FINAL WEIGHT	~~110.~~ 108.5009		110.4567	MT
INITIAL WEIGHT	108.4939		110.4565	
DIFFERENCE	0.0069		0.0002	
PARTICULATE CATCH	6.9		0.2	

TOTAL PARTICULATE CATCH (mg) 6.9

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	07	Filter Number	130
Plant	Spurlock	Nozzle No.	008	Initial Leak (Samp.)	0.000 @ 18'
Location	Unit 3	Nozzle Dn.	0.196	Initial Leak (Pitot)	∅ @ 25'
Test	PM	TC No.	004		∅ @ 28'
Run	2	P_B	29.44		
Date	6-16-05	Ambient Temp	75	Final Leak (Samp.)	0.000 @ 2'
Meter Box	083	Static	-0.86	Final Leak (Pitot)	∅ @ 3'
ΔH	1.71 | Y_1 1.005				∅ @ 3"

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	0940		170.593									
A1		5	173.6	1.7	1.95	175	241	242	76	76	50	1.5
2		10	177.4	1.7	1.95	176	242	237	77	77	47	1.5
3		15	181.999	1.5	1.73	178	243	239	78	78	49	1.5
B1		20	184.5	1.5	1.73	184	240	234	78	78	54	1.5
2		25	188.0	1.5	1.73	185	240	236	78	78	52	1.5
3		30	191.450	1.1	1.27	184	238	234	79	79	53	1.5
C1		35	194.8	1.5	1.73	183	242	242	79	79	57	1.5
2		40	198.0	1.5	1.73	182	244	245	79	79	54	1.5
3		45	201.050	1.1	1.27	181	244	247	79	79	54	1.5
D1		50	204.5	1.5	1.73	180	243	243	79	79	55	1.5
2		55	208.0	1.5	1.73	180	245	247	79	79	54	1.5
3	1044	60	210.789	0.85	0.98	178	244	244	80	80	55	1.5

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gibbet DATE: 6/16/05
SAMPLING TIME: (24 HR CLOCK) 0940 - 1044
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 80
TECHNICIAN: Heitman / Williams

Run 2
PM

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.8		13.8		13.8		13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.3	19.1	5.3	19.1	5.3	5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.2 / 20.2 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 19.8 / 19.8 BUBBLER

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	793.5	745.4	544.7				840.2	
INITIAL (ml)	701.8	727.1	542.8				826.3	
NET (ml)	91.7	18.3	1.9				13.9	125.8
TOTALS								125.8

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	130			WEIGHED BY
FINAL WEIGHT	0.2507			MT
INITIAL WEIGHT	0.2496			CH
DIFFERENCE	0.0011			MT
PARTICULATE CATCH	1.1			MT

PROBE/NOZZLE WASH

BEAKER NO.	31		Blank	WEIGHED BY
FINAL WEIGHT	109.0441			MT
INITIAL WEIGHT	109.0396			
DIFFERENCE	0.0045			
PARTICULATE CATCH	4.5		0.2	

TOTAL PARTICULATE CATCH (mg) 5.4

CATALYST AIR MANAGEMENT, INC.
Air Quality Testing Services
2505 Byington Solway Road
Knoxville, TN 37931
(865) 531-0075
(865) 531-0750 Fax

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	07	Filter Number	131
Plant	Spunlock	Nozzle No.	008	Initial Leak (Samp.)	0.000 @ 15"
Location	Unit 3	Nozzle Dn.	0.196	Initial Leak (Pitot)	ok @ 3
Test	PM	TC No.	04		ok @ 3
Run	3	P_B	29.44		
Date	6-16-05	Ambient Temp	75	Final Leak (Samp.)	0.000 @ 6"
Meter Box	083	Static	-0.90	Final Leak (Pitot)	ok @ 3
ΔH	1.71 | Y_1 1.005				ok @ 3

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1110		211.018									
A 1		5	214.5	1.5	1.73	171	242	236	78	78	63	4.0
2		10	218.0	1.5	1.73	171	242	238	78	78	47	4.0
3		15	221.250	0.95	1.09	170	243	231	79	79	46	4.0
B 1		20	224.8	1.5	1.73	171	244	230	79	79	50	4.0
2		25	228.2	1.5	1.73	171	244	231	80	80	48	4.0
3		30	231.590	1.1	1.27	172	244	231	80	80	49	4.0
C 1		35	234.8	1.5	1.73	174	240	238	80	80	53	4.0
2		40	238.3	1.5	1.73	178	241	239	80	80	53	4.0
3		45	241.570	1.1	1.27	178	242	233	81	81	53	4.0
D 1		50	244.9	1.5	1.73	177	242	232	80	80	61	4.0
2		55	248.4	1.5	1.73	177	247	232	81	81	53	4.0
3	1217	60	251.635	1.1	1.27	177	247	232	81	81	53	4.0

COMMENTS:

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Gilbert DATE: 6/16/05
SAMPLING TIME: (24 HR CLOCK) 1110 - 1217
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 80
TECHNICIAN: Heiten / Williams

Run 3
PM

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.8		13.8		13.8		13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.3	19.1	5.3	19.1	5.3	5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.2 / 20.2 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 19.8 / 19.8 BUBBLER ok

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	846.5	696.3	603.9				948.6	
INITIAL (ml)	746.4	683.1	601.4				938.3	
NET (ml)	100.1	13.2	2.5				10.3	126.1
TOTALS								126.1

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	131			WEIGHED BY
FINAL WEIGHT	0.2501			MT
INITIAL WEIGHT	0.2488			CW
DIFFERENCE	0.0013			MT
PARTICULATE CATCH	1.3			MT

PROBE/NOZZLE WASH

BEAKER NO.	28		Blank	WEIGHED BY
FINAL WEIGHT	109.4073			MT
INITIAL WEIGHT	109.4017			
DIFFERENCE	0.0056			
PARTICULATE CATCH	5.6		0.2	

TOTAL PARTICULATE CATCH (mg) 6.7

20% Opacity

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **1 -17%** Date: 8/17/05 Start Time: 8:10
End Time: 9:19

DIAMETER OF NOZZLE: 0.190
AREA OF NOZZLE: 1.97E-04 A_n
BAROMETRIC PRESSURE: 29.70 P_{bar}
GAS METER Y-FACTOR: 1.01 Y

STACK DIAMETER = 180 in
STACK AREA = 176.7 sq. ft.
VOLUME OF MOISTURE: 102.0 V_{lc}
PITOT COEFFICIENT: 0.84 C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		472.325										
A-1	5.0	475.5	1.50	1.30	81	80	174				30.84	75.6
2	5.0	478.6	1.50	1.30	81	80	175	13.9	5.3	-1.20	30.86	75.7
3	5.0	481.633	1.40	1.20	81	80	174				29.79	73.0
		481.633										
B-1	5.0	484.7	1.60	1.40	83	80	173				31.82	78.0
2	5.0	487.9	1.60	1.40	84	80	174				31.85	78.1
3	5.0	490.929	1.40	1.20	85	81	173				29.77	73.0
		490.929										
C-1	5.0	493.9	1.50	1.30	86	82	173				30.81	75.5
2	5.0	497.0	1.50	1.30	86	82	174				30.84	75.6
3	5.0	499.931	1.30	1.10	86	82	174				28.71	70.4
		499.931										
D-1	5.0	503.1	1.60	1.40	86	83	174				31.85	78.1
2	5.0	506.3	1.60	1.40	88	84	175				31.87	78.1
3	5.0	509.307	1.30	1.10	88	83	175				28.73	70.4
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	36.982	1.217	1.283		83	174	13.9	5.3	-1.20	30.65	75.1
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s = 29.61 $V_{m(std)}$ = 36.153 $V_{w(std)}$ = 4.804 %M= 11.73
B_{ws} = 0.117 M_d = 30.44 M_s = 28.98 %EA= 33.06

STACK GAS VELOCITY = 75.1 AFPS V_s
STACK GAS VELOCITY = 4,508 AFPM
STACK GAS VOLUME = 579,507 DSCFM Q_{std}
STACK GAS VOLUME = 796,521 ACFM Q_a
ISOKINETIC RATIO = 93.4 %

PARTICULATE EMISSIONS
Weight, mg = 80.2
GR/DSCF = 0.034
LBS/MMBTU = **0.064**

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **2-17%** Date: 8/17/05 Start Time: 10:05
End Time: 11:14

DIAMETER OF NOZZLE:	0.190		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.97E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.70	P_{bar}	VOLUME OF MOISTURE:	107.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		509.682										
A-1	5.0	513.0	1.60	1.40	86	84	174				31.85	78.2
2	5.0	516.1	1.60	1.40	87	84	175	13.9	5.2	-1.20	31.87	78.2
3	5.0	519.158	1.40	1.20	87	83	176				29.84	73.2
		519.158										
B-1	5.0	522.2	1.50	1.30	89	85	175				30.86	75.8
2	5.0	525.3	1.50	1.30	89	85	175				30.86	75.8
3	5.0	528.207	1.30	1.10	90	85	174				28.71	70.5
		528.207										
C-1	5.0	531.6	1.60	1.40	90	86	174				31.85	78.2
2	5.0	534.5	1.60	1.40	91	86	175				31.87	78.2
3	5.0	537.564	1.40	1.20	92	87	175				29.82	73.2
		537.564										
D-1	5.0	540.7	1.60	1.40	91	87	175				31.87	78.2
2	5.0	543.8	1.50	1.30	91	87	175				30.86	75.8
3	5.0	546.730	1.30	1.10	92	87	175				28.73	70.5
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	37.048	1.220	1.292		88	175	13.9	5.2	-1.20	30.75	75.5
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.61	$V_{m(std)}$ =	35.918	$V_{w(std)}$ =	5.040	%M=	12.30
B_{ws} =	0.123	M_d =	30.43	M_s =	28.90	%EA=	32.18

STACK GAS VELOCITY =	75.5	AFPS	V_s
STACK GAS VELOCITY =	4,529	AFPM	
STACK GAS VOLUME =	577,685	DSCFM	Q_{std}
STACK GAS VOLUME =	800,273	ACFM	Q_a
ISOKINETIC RATIO =	93.1	%	

PARTICULATE EMISSIONS

Weight, mg =	83.3
GR/DSCF =	0.036
LBS/MMBTU =	**0.067**

Catalyst Air Management, Inc.

Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **3-17%** Date: 8/17/05 Start Time: 11:40
End Time: 12:49

DIAMETER OF NOZZLE:	0.185		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.87E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.70	P_{bar}	VOLUME OF MOISTURE:	109.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		547.334										
A-1	5.0	550.5	1.60	1.30	89	86	174				31.85	78.3
2	5.0	553.6	1.50	1.20	89	86	175	13.7	5.4	-1.20	30.86	75.9
3	5.0	556.404	1.30	1.00	90	86	175				28.73	70.6
		556.404										
B-1	5.0	559.4	1.50	1.20	91	86	175				30.86	75.9
2	5.0	562.3	1.50	1.20	92	86	175				30.86	75.9
3	5.0	565.156	1.30	1.00	92	86	174				28.71	70.6
		565.156										
C-	5.0	568.1	1.50	1.20	93	89	174				30.84	75.8
2	5.0	571.2	1.60	1.30	93	89	175				31.87	78.4
3	5.0	574.132	1.40	1.10	93	89	175				29.82	73.3
		574.132										
D-1	5.0	577.2	1.60	1.30	93	90	175				31.87	78.4
2	5.0	580.3	1.60	1.30	93	90	175				31.87	78.4
3	5.0	583.207	1.40	1.10	94	90	174				29.79	73.3
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	35.873	1.217	1.183		90	175	13.7	5.4	-1.20	30.66	75.4
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.61	$V_{m(std)}$ =	34.627	$V_{w(std)}$ =	5.134	%M=	12.91
B_{ws} =	0.129	M_d =	30.41	M_s =	28.81	%EA=	33.84

STACK GAS VELOCITY =	75.4	AFPS	V_s
STACK GAS VELOCITY =	4,524	AFPM	
STACK GAS VOLUME =	573,147	DSCFM	Q_{std}
STACK GAS VOLUME =	799,312	ACFM	Q_a
ISOKINETIC RATIO =	95.4	%	

PARTICULATE EMISSIONS

Weight, mg =	86.0
GR/DSCF =	0.038
LBS/MMBTU =	**0.072**

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1159
Plant	SPURLOCK	Nozzle No.	04	Initial Leak (Samp.)	0.000 @12"
Location	U-3 STACK	Nozzle Dn.	0.190	Initial Leak (Pitot)	OK @ 5"
Test	M-5	TC No.	CAM-07		OK @ 6"
Run	1 - 2002	P_B	29.70		
Date	8-~~16~~ 17-05	Ambient Temp	77	Final Leak (Samp.)	0.000 @ 20"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK @ 6"
ΔH	1.55 | Y_1 1.01				OK @ 6"

K=0.91

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	810		472.325									
A-1		5	475.5	1.5	1.3	174	243	251	81	80	65	1.0
2		10	478.6	1.5	1.3	175	241	254	81	80	61	1.0
3	825	15	481.633	1.4	1.2	174	246	253	81	80	60	1.0
	828		481.633									
B-1		20	484.7	1.6	1.4	173	250	257	83	80	66	1.0
2		25	487.9	1.6	1.4	174	247	250	84	80	63	1.0
3	843	30	490.929	1.4	1.2	173	245	255	85	81	62	1.0
	846		490.929									
C-1		35	493.9	1.5	1.3	173	253	257	86	82	65	1.0
2		40	497.0	1.5	1.3	174	258	257	86	82	63	1.0
3	901	45	499.931	1.3	1.1	174	251	254	86	82	62	1.0
	904		499.931									
D-1		50	503.1	1.6	1.4	174	253	251	87	83	66	1.0
2		55	506.3	1.6	1.4	175	248	248	88	84	63	2.0
3	919	60	509.307	1.3	1.1	175	249	248	88	83	62	2.0

COMMENTS: IMPS 1 172 GEL 256 250

2 120

3 4

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/17/05
SAMPLING TIME: (24 HR CLOCK) 0810 - 0919
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 77
TECHNICIAN: Love / Hale / Taylor

Run 1
20%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.9		13.9		13.9 ~~19~~		13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.2	5.3	19.2	5.3	19.2	5.3	5.3	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK [illegible]
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER [illegible]
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER [illegible]

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	172	120	4				256	
INITIAL (ml)	100	100	0				250	
NET (ml)	72	20	4				6	102.0
TOTALS								102.0

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1159			WEIGHED BY
FINAL WEIGHT	1.0580			MT
INITIAL WEIGHT	0.9929			CA
DIFFERENCE	0.0651			MT
PARTICULATE CATCH	65.1			MT

PROBE/NOZZLE WASH

BEAKER NO.	25		Blank	WEIGHED BY
FINAL WEIGHT	103.5936		110.4832	MT
INITIAL WEIGHT	103.5785		110.4832	
DIFFERENCE	0.0151		0	
PARTICULATE CATCH	15.1		0	

TOTAL PARTICULATE CATCH (mg) 80.2

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1180
Plant	SPURLOCK	Nozzle No.	41	Initial Leak (Samp.)	0.000@8"
Location	U-3 STACK	Nozzle Dn.	0.090	Initial Leak (Pitot)	OK@6"
Test	M-5	TC No.	CAM-07		OK@5"
Run	2	P_B	29.70		
Date	8-17-05	Ambient Temp	83	Final Leak (Samp.)	0.005@5"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK@6"
ΔH	1.55 | Y_1 1.01				OK@8"

K=0.91

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1005		509.682									
D-1		5	513.0	1.6	1.4	174	249	251	86	84	65	1.0
2		10	516.1	1.6	1.4	175	244	245	87	84	62	1.0
3	1020	15	519.158	1.4	1.2	176	249	253	87	83	61	1.0
	1023		519.158									
C-1		20	522.2	1.5	1.3	175	256	256	89	85	65	1.0
2		25	525.3	1.5	1.3	175	249	251	89	85	63	1.0
3	1038	30	528.207	1.3	1.1	174	249	256	90	85	62	1.0
	1041		528.207									
B-1		35	531.6	1.6	1.4	174	252	254	90	86	66	1.0
2		40	534.5	1.6	1.4	175	249	254	91	86	63	1.0
3	1056	45	537.564	1.4	1.2	175	248	251	92	87	60	1.0
	1059		537.564									
A-1		50	540.7	1.6	1.4	175	248	257	91	87	65	1.0
2		55	543.8	1.5	1.3	175	251	255	91	87	63	1.0
3	1114	60	546.730	1.3	1.1	175	248	254	92	87	61	1.0

COMMENTS: IMPS 1 178
2 120
3 2

GEL 257
250

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/17/05
SAMPLING TIME: (24 HR CLOCK) 1005 - 1114
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: ~~B.~~ Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP(°F) 83
TECHNICIAN: Love / Helo / Taylor

Run 2
20%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.9		13.9		13.9		13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.2	19.1	5.2	19.1	5.2	5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	178	120	2				257	
INITIAL (ml)	100	100	0				250	
NET (ml)	78	20	2				7	107.0
TOTALS								107.0

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1180			WEIGHED BY
FINAL WEIGHT	1.0759			MT
INITIAL WEIGHT	1.0289			CA
DIFFERENCE	0.0469			MT
PARTICULATE CATCH	46.9			MT

PROBE/NOZZLE WASH

BEAKER NO.	24		Blank	WEIGHED BY
FINAL WEIGHT	100.1273			MT
INITIAL WEIGHT	100.0909			
DIFFERENCE	0.0364			
PARTICULATE CATCH	36.4		0	

TOTAL PARTICULATE CATCH (mg) 83.3

CATALYST AIR MANAGEMENT, INC.
Air Quality Testing Services
2505 Byington Solway Road
Knoxville, TN 37931
(865) 531-0075
(865) 531-0750 Fax

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1183
Plant	SPURLOCK	Nozzle No.	CAM-102	Initial Leak (Samp.)	0.000 @ 8"
Location	U-3 STACK	Nozzle Dn.	0.185	Initial Leak (Pitot)	OK @ 6"
Test	M-5	TC No.	CAM-07		OK @ 6"
Run	3	P_B	29.70		
Date	8-17-05	Ambient Temp	86	Final Leak (Samp.)	0.002 @
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK @ 5"
ΔH	1.55 | Y_1 1.01				OK @ 6"

K = 0.82

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1140		547.334									
A-1		5	550.5	1.6	~~1.4~~ 1.3	174	249	252	89	86	65	1.0
2		10	553.6	1.5	~~1.3~~ 1.2	175	247	251	89	86	62	1.0
3	1155	15	556.404	1.3	1.0	175	247	253	90	86	61	1.0
	1158		556.404									
B-1		20	559.4	1.5	1.2	175	247	257	91	86	63	1.0
2		25	562.3	1.5	1.2	175	250	258	92	86	60	1.0
3	1213	30	565.156	1.3	1.0	174	250	256	92	86	59	1.0
	1216		565.156									
C-1		35	568.1	1.5	1.2	174	253	258	93	89	64	1.0
2		40	571.2	1.6	1.3	175	254	259	93	89	61	1.5
3	1231	45	574.132	1.4	1.1	175	249	257	93	89	61	1.5
	1234		574.132									
D-1		50	577.2	1.6	1.3	175	249	253	93	90	65	1.5
2		55	580.3	1.6	1.3	175	247	250	93	90	62	1.5
3	1249	60	~~583.215~~	1.4	1.1	174	243	247	94	90	62	1.5
			583.207									

COMMENTS: IMPS 1 190
2 110
3 4

GEL 255
250

83

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/17/05
SAMPLING TIME: (24 HR CLOCK) 1140 - 1249
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 86
TECHNICIAN: Love / Hawe / Taylor

Run 3
20%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.7		13.7		13.7		13.7		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.4	19.1	5.4	19.1	5.4	5.4	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	190	110	4				255	
INITIAL (ml)	100	100	0				250	
NET (ml)	90	10	4				5	109.0
TOTALS								109.0

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C-1183			WEIGHED BY	BEAKER NO.	05		Blank	WEIGHED BY
FINAL WEIGHT	1.0489			MT	FINAL WEIGHT	103.1414			MT
INITIAL WEIGHT	0.9982			CA	INITIAL WEIGHT	103.1061			
DIFFERENCE	0.0507			MT	DIFFERENCE	0.0353			
PARTICULATE CATCH	50.7			MT	PARTICULATE CATCH	35.3		0	

TOTAL PARTICULATE CATCH (mg) 86.0

run 1
20%

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:03

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	08:11	19.5	290.6	3.919E+07	0.211	0.085	0.08	5.18	4.90
	08:12	19.9	290.8	3.928E+07	0.243	0.100	0.08	5.22	4.90
	08:13	19.2	290.9	3.926E+07	0.225	0.088	0.08	5.25	4.92
	08:14	19.1	290.0	3.930E+07	0.212	0.085	0.08	5.14	4.89
	08:15	19.2	289.3	3.928E+07	0.217	0.084	0.08	5.20	4.95
	08:16	18.5	288.8	3.926E+07	0.194	0.088	0.08	5.16	4.88
	08:17	18.7	289.0	3.929E+07	0.191	0.085	0.08	5.22	4.94
	08:18	18.0	289.2	3.922E+07	0.183	0.089	0.08	5.16	4.90
	08:19	18.3	289.5	3.923E+07	0.184	0.087	0.08	5.24	4.95
	08:20	17.6	289.9	3.930E+07	0.187	0.098	0.08	5.10	4.70
	08:21	17.8	289.5	3.918E+07	0.176	0.085	0.08	5.17	4.84
	08:22	18.3	289.1	3.915E+07	0.164	0.088	0.08	5.21	4.91
	08:23	17.8	288.6	3.924E+07	0.196	0.090	0.08	5.14	4.93
	08:24	18.7	288.4	3.926E+07	0.182	0.087	0.08	5.31	5.07
	08:25	16.8	288.5	3.918E+07	0.196	0.090	0.08	5.01	4.73
	08:26	17.9	288.4	3.916E+07	0.205	0.090	0.08	5.24	4.96
	08:27	17.4	288.3	3.925E+07	0.180	0.084	0.08	5.11	4.78
	08:28	17.7	288.7	3.928E+07	0.165	0.083	0.08	5.20	4.85
	08:29	17.0	288.8	3.928E+07	0.170	0.082	0.08	5.09	4.71
	08:30	16.6	289.0	3.925E+07	0.182	0.083	0.08	5.08	4.68
	08:31	16.6	290.2	3.919E+07	0.183	0.083	0.08	5.11	4.69
	08:32	16.2	291.3	3.918E+07	0.193	0.087	0.08	5.08	4.86
	08:33	17.0	291.6	3.916E+07	0.223	0.087	0.08	5.21	5.07
	08:34	16.7	291.4	3.921E+07	0.208	0.095	0.08	5.16	4.91
	08:35	17.2	290.9	3.936E+07	0.201	0.087	0.08	5.23	4.93
	08:36	15.3	289.8	3.945E+07	0.210	0.084	0.08	5.05	4.71
	08:37	16.4	288.8	3.936E+07	0.199	0.083	0.08	5.16	4.84
	08:38	15.4	288.7	3.925E+07	0.202	0.086	0.08	5.04	4.72
	08:39	15.7	288.8	3.914E+07	0.230	0.091	0.08	5.10	4.80
	08:40	14.9	288.7	3.908E+07	0.243	0.090	0.08	5.08	4.77
	08:41	15.6	288.6	3.913E+07	0.249	0.094	0.08	5.08	4.76
	08:42	15.4	288.8	3.919E+07	0.262	0.093	0.08	5.09	4.77
	08:43	15.3	289.0	3.923E+07	0.247	0.086	0.08	5.06	4.80
	08:44	15.8	289.4	3.922E+07	0.219	0.089	0.08	5.18	4.88
	08:45	15.1	289.8	3.929E+07	0.238	0.087	0.08	5.06	4.76
	08:46	15.9	289.8	3.937E+07	0.200	0.084	0.08	5.16	4.87
	08:47	15.0	289.8	3.951E+07	0.204	0.087	0.08	5.07	4.74
	08:48	15.8	289.4	3.961E+07	0.205	0.085	0.08	5.18	4.86
	08:49	14.5	289.2	3.963E+07	0.200	0.084	0.08	5.04	4.63
	08:50	15.2	289.2	3.966E+07	0.207	0.084	0.08	5.10	4.79
	08:51	15.2	289.2	3.964E+07	0.213	0.090	0.08	5.14	4.81
	08:52	14.7	288.9	3.957E+07	0.209	0.088	0.08	5.08	4.67
	08:53	14.9	288.4	3.960E+07	0.199	0.086	0.08	5.07	4.84
	08:54	15.2	288.4	3.966E+07	0.216	0.088	0.08	5.17	4.87
	08:55	14.0	288.3	3.951E+07	0.199	0.083	0.08	5.04	4.65
	08:56	14.7	288.2	3.935E+07	0.180	0.083	0.08	5.12	4.83
	08:57	15.3	288.4	3.942E+07	0.177	0.083	0.08	5.18	4.94
	08:58	13.5	288.4	3.951E+07	0.177	0.084	0.08	4.94	4.59
	08:59	14.3	288.6	3.948E+07	0.164	0.082	0.08	5.08	4.70
	09:00	14.1	288.6	3.943E+07	0.175	0.086	0.08	4.97	4.63

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Time of Report: 08/18/05 13:03

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	09:01	14.3	288.3	3.946E+07	0.177	0.083	0.08	5.15	4.82
	09:02	13.4	288.6	3.953E+07	0.178	0.083	0.08	4.91	4.51
	09:03	14.5	289.0	3.948E+07	0.176	0.082	0.08	5.17	4.80
	09:04	13.5	289.2	3.959E+07	0.158	0.079	0.08	4.98	4.67
	09:05	14.8	289.1	3.978E+07	0.142	0.079	0.08	5.14	4.80
	09:06	13.4	289.0	4.010E+07	0.153	0.080	0.08	4.96	4.58
	09:07	14.1	289.5	4.014E+07	0.151	0.082	0.08	5.14	4.78
	09:08	13.4	289.6	4.012E+07	0.161	0.083	0.08	5.01	4.60
	09:09	14.4	289.3	4.006E+07	0.177	0.083	0.08	5.13	4.77
	09:10	14.3	289.8	4.017E+07	0.155	0.082	0.08	5.16	4.90
	09:11	13.6	290.5	4.037E+07	0.169	0.085	0.08	5.03	4.70
	09:12	14.1	290.8	4.055E+07	0.178	0.084	0.08	5.13	4.78
	09:13	13.6	290.8	4.058E+07	0.161	0.086	0.08	5.03	4.62
	09:14	14.1	291.5	4.046E+07	0.166	0.086	0.08	5.16	4.86
	09:15	13.8	292.2	4.052E+07	0.169	0.085	0.09	5.08	4.73
	09:16	14.5	292.3	4.077E+07	0.160	0.086	0.09	5.17	4.82
	09:17	13.6	292.2	4.086E+07	0.128	0.084	0.09	5.04	4.69
	09:18	14.7	291.8	4.095E+07	0.141	0.085	0.09	5.23	4.89
	09:19	14.7	291.4	4.119E+07	0.140	0.086	0.09	5.29	4.87
Average =		15.8	289.5	3.958E+07	0.190	0.086	0.08	5.12	4.80
Maximum =		19.9	292.3	4.119E+07	0.262	0.100	0.09	5.31	5.07
Minimum =		13.4	288.2	3.908E+07	0.128	0.079	0.08	4.91	4.51
Possible Values =		69	69	69	69	69	69	69	69
cluded Values =		69	69	69	69	69	69	69	69
Total =		1091.7	19978.5	2.731E+09	13.137	5.934	5.61	353.36	331.30

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

run 2
20%

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:04

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	10:06	19.8	287.5	3.966E+07	0.176	0.082	0.08	4.94	4.54
	10:07	19.6	287.7	3.964E+07	0.177	0.082	0.08	5.02	4.61
	10:08	20.2	287.4	3.970E+07	0.184	0.088	0.08	5.03	4.72
	10:09	19.0	286.9	3.969E+07	0.203	0.089	0.08	4.93	4.52
	10:10	19.1	286.7	3.962E+07	0.188	0.083	0.08	4.96	4.60
	10:11	18.8	286.9	3.964E+07	0.203	0.088	0.08	4.92	4.52
	10:12	18.9	287.1	3.972E+07	0.218	0.085	0.08	4.98	4.59
	10:13	19.0	287.3	3.972E+07	0.197	0.083	0.08	4.91	4.62
	10:14	19.0	287.3	3.974E+07	0.193	0.086	0.08	5.01	4.66
	10:15	18.1	287.4	3.975E+07	0.197	0.085	0.08	4.87	4.53
	10:16	18.7	287.7	3.968E+07	0.208	0.086	0.08	4.91	4.53
	10:17	18.7	288.3	3.963E+07	0.187	0.085	0.08	4.97	4.61
	10:18	18.8	288.7	3.965E+07	0.177	0.082	0.08	4.98	4.65
	10:19	17.9	288.8	3.967E+07	0.210	0.084	0.08	4.85	4.40
	10:20	18.2	289.7	3.962E+07	0.204	0.086	0.08	4.96	4.62
	10:21	18.0	289.7	3.950E+07	0.225	0.087	0.08	5.00	4.68
	10:22	17.8	289.3	3.941E+07	0.217	0.086	0.08	4.89	4.50
	10:23	17.6	288.6	3.929E+07	0.201	0.082	0.08	4.90	4.52
	10:24	17.7	287.9	3.919E+07	0.213	0.081	0.08	4.89	4.57
	10:25	17.7	287.3	3.932E+07	0.204	0.079	0.08	4.88	4.46
	10:26	17.5	287.1	3.934E+07	0.196	0.085	0.08	4.87	4.49
	10:27	17.4	287.4	3.928E+07	0.189	0.078	0.08	4.86	4.46
	10:28	17.4	287.7	3.925E+07	0.188	0.078	0.08	4.90	4.56
	10:29	17.1	287.9	3.928E+07	0.177	0.079	0.08	4.85	4.48
	10:30	17.3	288.3	3.949E+07	0.209	0.085	0.08	4.84	4.42
	10:31	17.7	288.1	3.957E+07	0.215	0.081	0.08	4.90	4.50
	10:32	17.0	287.9	3.927E+07	0.197	0.080	0.08	4.82	4.46
	10:33	17.4	287.2	3.916E+07	0.206	0.084	0.08	4.90	4.50
	10:34	17.6	286.4	3.926E+07	0.211	0.087	0.08	4.88	4.62
	10:35	18.0	286.1	3.934E+07	0.201	0.079	0.08	4.99	4.67
	10:36	16.7	286.3	3.945E+07	0.215	0.091	0.08	4.82	4.42
	10:37	17.8	286.4	3.947E+07	0.235	0.085	0.08	4.96	4.56
	10:38	17.3	286.4	3.946E+07	0.202	0.082	0.08	4.84	4.54
	10:39	17.6	286.7	3.954E+07	0.202	0.083	0.08	4.96	4.59
	10:40	16.3	287.5	3.957E+07	0.206	0.081	0.08	4.80	4.41
	10:41	17.5	288.4	3.948E+07	0.191	0.080	0.08	4.95	4.58
	10:42	17.2	289.3	3.961E+07	0.181	0.080	0.08	4.83	4.49
	10:43	17.7	289.6	3.973E+07	0.182	0.080	0.08	4.93	4.64
	10:44	16.6	289.8	3.980E+07	0.173	0.079	0.08	4.82	4.42
	10:45	18.2	289.8	3.986E+07	0.172	0.079	0.09	5.05	4.67
	10:46	17.1	289.5	3.986E+07	0.173	0.080	0.09	4.94	4.54
	10:47	17.6	289.1	3.986E+07	0.161	0.079	0.09	5.00	4.66
	10:48	17.7	288.7	3.990E+07	0.150	0.079	0.09	5.00	4.77
	10:49	17.5	288.1	3.991E+07	0.167	0.080	0.09	5.08	4.91
	10:50	17.3	287.6	3.980E+07	0.154	0.078	0.09	5.02	4.71
	10:51	16.7	287.3	3.979E+07	0.143	0.079	0.09	4.95	4.56
	10:52	16.7	287.2	3.988E+07	0.154	0.078	0.09	4.96	4.58
	10:53	17.3	287.3	3.986E+07	0.143	0.079	0.09	5.02	4.69
	10:54	16.3	287.5	3.978E+07	0.151	0.079	0.09	4.91	4.54
	10:55	16.9	288.8	3.983E+07	0.147	0.080	0.09	5.06	4.70

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Time of Report: 08/18/05 13:04

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	10:56	16.4	289.5	4.002E+07	0.153	0.078	0.09	4.96	4.53
	10:57	16.5	289.6	4.017E+07	0.128	0.076	0.09	4.97	4.59
	10:58	16.1	289.5	4.009E+07	0.131	0.078	0.09	4.99	4.61
	10:59	15.6	289.5	4.002E+07	0.143	0.080	0.09	4.89	4.50
	11:00	16.3	288.9	3.994E+07	0.150	0.079	0.09	5.05	4.73
	11:01	16.1	288.2	3.994E+07	0.134	0.078	0.09	4.96	4.59
	11:02	16.7	288.4	4.012E+07	0.132	0.079	0.09	5.04	4.65
	11:03	16.6	288.4	4.016E+07	0.132	0.078	0.09	5.01	4.63
	11:04	16.0	288.5	4.009E+07	0.128	0.080	0.09	4.95	4.60
	11:05	16.6	288.7	4.011E+07	0.128	0.082	0.09	5.08	4.78
	11:06	16.4	288.5	4.019E+07	0.118	0.079	0.09	4.99	4.56
	11:07	16.5	289.2	4.021E+07	0.104	0.078	0.09	5.04	4.67
	11:08	17.3	290.4	4.021E+07	0.098	0.078	0.09	5.06	4.66
	11:09	16.5	291.1	4.021E+07	0.118	0.079	0.09	5.06	4.86
	11:10	16.9	291.1	4.021E+07	0.118	0.080	0.09	5.15	4.86
	11:11	15.9	291.0	4.025E+07	0.104	0.078	0.09	5.05	4.61
	11:12	16.7	290.5	4.038E+07	0.100	0.080	0.09	5.06	4.77
	11:13	16.8	290.5	4.041E+07	0.093	0.080	0.09	5.13	4.77
	11:14	15.6	290.6	4.042E+07	0.090	0.080	0.09	5.01	4.64
Average =		17.4	288.3	3.975E+07	0.171	0.081	0.08	4.96	4.60
Maximum =		20.2	291.1	4.042E+07	0.235	0.091	0.09	5.15	4.91
Minimum =		15.6	286.1	3.916E+07	0.090	0.076	0.08	4.80	4.40
Possible Values =		69	69	69	69	69	69	69	69
cluded Values =		69	69	69	69	69	69	69	69
Total =		1202.2	19895.3	2.743E+09	11.782	5.614	5.82	341.99	317.23

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

run 3
20%

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:04

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	11:41	21.0	293.1	4.107E+07	0.059	0.078	0.10	5.17	4.81
	11:42	20.5	293.3	4.106E+07	0.061	0.079	0.10	5.15	4.72
	11:43	21.1	293.7	4.116E+07	0.064	0.079	0.10	5.28	4.94
	11:44	20.4	293.5	4.130E+07	0.054	0.077	0.10	5.11	4.76
	11:45	21.1	293.3	4.142E+07	0.053	0.079	0.10	5.31	4.93
	11:46	20.3	292.6	4.142E+07	0.072	0.080	0.10	5.13	4.71
	11:47	21.2	291.5	4.138E+07	0.066	0.080	0.10	5.25	4.85
	11:48	19.9	291.3	4.136E+07	0.068	0.079	0.10	5.13	4.81
	11:49	20.8	291.2	4.122E+07	0.064	0.079	0.10	5.22	4.94
	11:50	19.7	291.6	4.135E+07	0.058	0.079	0.10	5.17	4.79
	11:51	20.0	291.7	4.157E+07	0.059	0.079	0.10	5.12	4.76
	11:52	21.5	291.7	4.159E+07	0.058	0.079	0.10	5.32	4.92
	11:53	20.1	292.3	4.161E+07	0.058	0.078	0.10	5.16	4.84
	11:54	19.8	293.3	4.149E+07	0.062	0.079	0.10	5.21	4.95
	11:55	19.4	293.1	4.137E+07	0.064	0.079	0.10	5.18	4.79
	11:56	19.2	292.8	4.145E+07	0.050	0.079	0.10	5.16	4.78
	11:57	18.8	292.2	4.146E+07	0.041	0.081	0.10	5.11	4.80
	11:58	19.9	292.1	4.143E+07	0.031	0.079	0.10	5.31	4.96
	11:59	18.1	291.4	4.142E+07	0.029	0.079	0.10	5.10	4.67
	12:00	19.0	291.3	4.127E+07	0.029	0.078	0.10	5.18	4.86
	12:01	19.0	290.8	4.117E+07	0.032	0.079	0.10	5.15	4.84
	12:02	18.0	290.1	4.101E+07	0.030	0.078	0.10	5.00	4.63
	12:03	17.8	289.6	4.083E+07	0.031	0.077	0.10	5.04	4.70
	12:04	18.0	289.5	4.059E+07	0.038	0.078	0.10	5.07	4.73
	12:05	17.2	290.0	4.051E+07	0.049	0.078	0.10	4.99	4.67
	12:06	18.1	289.8	4.051E+07	0.066	0.078	0.09	5.06	4.72
	12:07	16.7	289.6	4.033E+07	0.061	0.076	0.09	4.90	4.56
	12:08	17.8	289.6	4.010E+07	0.063	0.075	0.09	5.04	4.78
	12:09	16.5	289.5	3.988E+07	0.077	0.075	0.09	4.90	4.62
	12:10	16.5	289.0	3.977E+07	0.075	0.074	0.09	4.97	4.71
	12:11	16.6	288.4	3.969E+07	0.069	0.073	0.09	4.93	4.66
	12:12	16.0	288.6	3.956E+07	0.078	0.072	0.09	4.91	4.54
	12:13	15.3	289.0	3.938E+07	0.092	0.071	0.09	4.76	4.39
	12:14	16.4	289.3	3.911E+07	0.102	0.071	0.09	4.94	4.60
	12:15	14.8	289.6	3.892E+07	0.121	0.070	0.09	4.74	4.40
	12:16	15.5	289.5	3.877E+07	0.130	0.070	0.08	4.91	4.54
	12:17	15.0	289.7	3.859E+07	0.150	0.069	0.08	4.79	4.41
	12:18	16.0	290.0	3.852E+07	0.138	0.073	0.08	4.89	4.56
	12:19	16.2	289.9	3.857E+07	0.168	0.072	0.08	4.91	4.53
	12:20	15.5	289.5	3.856E+07	0.174	0.073	0.08	4.78	4.48
	12:21	16.3	289.6	3.858E+07	0.175	0.074	0.08	4.89	4.59
	12:22	14.9	289.6	3.866E+07	0.176	0.072	0.08	4.79	4.39
	12:23	16.0	289.7	3.858E+07	0.157	0.068	0.08	4.91	4.53
	12:24	14.9	290.0	3.856E+07	0.171	0.070	0.08	4.73	4.40
	12:25	16.0	290.0	3.861E+07	0.184	0.076	0.08	4.93	4.57
	12:26	15.3	290.0	3.866E+07	0.186	0.073	0.08	4.86	4.44
	12:27	15.5	289.9	3.862E+07	0.189	0.076	0.08	4.86	4.54
	12:28	15.5	289.4	3.857E+07	0.174	0.072	0.08	4.84	4.48
	12:29	14.9	288.6	3.856E+07	0.170	0.071	0.08	4.78	4.37
	12:30	15.2	288.0	3.863E+07	0.165	0.076	0.08	4.82	4.43

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:04

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	12:31	15.5	287.8	3.880E+07	0.196	0.094	0.08	4.87	4.48
	12:32	15.5	288.1	3.879E+07	0.193	0.087	0.08	4.89	4.54
	12:33	15.0	288.1	3.884E+07	0.165	0.077	0.08	4.79	4.34
	12:34	15.8	288.4	3.892E+07	0.148	0.071	0.08	4.93	4.60
	12:35	15.9	288.5	3.886E+07	0.140	0.073	0.08	4.92	4.65
	12:36	15.8	288.8	3.888E+07	0.148	0.077	0.08	4.86	4.49
	12:37	16.0	288.8	3.905E+07	0.155	0.078	0.08	4.88	4.46
	12:38	16.1	288.7	3.913E+07	0.143	0.074	0.08	4.86	4.54
	12:39	15.4	288.2	3.896E+07	0.139	0.073	0.09	4.83	4.43
	12:40	15.4	287.5	3.891E+07	0.118	0.072	0.09	4.80	4.51
	12:41	16.1	286.8	3.884E+07	0.108	0.071	0.09	4.92	4.57
	12:42	14.8	286.1	3.880E+07	0.126	0.078	0.09	4.78	4.35
	12:43	16.0	285.5	3.875E+07	0.137	0.074	0.09	4.83	4.52
	12:44	15.9	285.7	3.880E+07	0.132	0.082	0.09	4.94	4.57
	12:45	14.4	285.8	3.895E+07	0.145	0.078	0.09	4.73	4.36
	12:46	15.2	285.8	3.897E+07	0.148	0.076	0.09	4.88	4.50
	12:47	14.9	285.2	3.894E+07	0.142	0.077	0.08	4.78	4.35
	12:48	15.6	284.4	3.889E+07	0.120	0.076	0.09	4.86	4.57
	12:49	14.9	284.4	3.884E+07	0.107	0.072	0.08	4.76	4.46
Average =		17.2	289.6	3.981E+07	0.106	0.076	0.09	4.97	4.62
Maximum =		21.5	293.7	4.161E+07	0.196	0.094	0.10	5.32	4.96
Minimum =		14.4	284.4	3.852E+07	0.029	0.068	0.08	4.73	4.34
Possible Values =		69	69	69	69	69	69	69	69
cluded Values =		69	69	69	69	69	69	69	69
Total =		1183.6	19985.6	2.747E+09	7.302	5.252	6.22	342.98	318.70

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

8% Opacity

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **1-8.5%** Date: 8/17/05 Start Time: 13:25
End Time: 14:34

DIAMETER OF NOZZLE:	0.190		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.97E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.70	P_{bar}	VOLUME OF MOISTURE:	113.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		583.421										
A-1	5.0	586.7	1.60	1.40	90	89	174				31.85	78.3
2	5.0	589.9	1.60	1.40	91	89	175	13.8	5.3	-1.20	31.87	78.4
3	5.0	592.917	1.40	1.20	92	87	175				29.82	73.3
		592.917										
B-1	5.0	596.0	1.50	1.30	92	88	174				30.84	75.8
2	5.0	599.1	1.50	1.30	92	88	175				30.86	75.9
3	5.0	602.095	1.30	1.10	94	89	175				28.73	70.6
		602.095										
C-1	5.0	605.3	1.60	1.40	95	90	174				31.85	78.3
2	5.0	608.5	1.60	1.40	95	90	175				31.87	78.4
3	5.0	611.403	1.30	1.10	95	90	175				28.73	70.6
		611.403										
D-1	5.0	614.4	1.50	1.30	95	91	175				30.86	75.9
2	5.0	617.6	1.50	1.30	96	91	175				30.86	75.9
3	5.0	620.460	1.30	1.10	96	91	175				28.73	70.6
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	37.039	1.214	1.275		92	175	13.8	5.3	-1.20	30.57	75.2
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.61	$V_{m(std)}$ =	35.650	$V_{w(std)}$ =	5.322	%M=	12.99
B_{ws} =	0.130	M_d =	30.42	M_s =	28.81	%EA=	33.01

STACK GAS VELOCITY =	75.2	AFPS	V_s
STACK GAS VELOCITY =	4,510	AFPM	
STACK GAS VOLUME =	570,895	DSCFM	Q_{std}
STACK GAS VOLUME =	796,991	ACFM	Q_a
ISOKINETIC RATIO =	93.5	%	

PARTICULATE EMISSIONS

Weight, mg =	25.2
GR/DSCF =	0.011
LBS/MMBTU =	**0.020**

Catalyst Air Management, Inc.

Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **2-8.5%** Date: 8/17/05 Start Time: 14:52
End Time: 16:01

DIAMETER OF NOZZLE:	0.190		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.97E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.70	P_{bar}	VOLUME OF MOISTURE:	110.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		620.711										
A-1	5.0	623.9	1.50	1.30	93	90	175				30.86	75.8
2	5.0	627.0	1.50	1.30	94	90	175	13.8	5.2	-1.20	30.86	75.8
3	5.0	629.935	1.30	1.10	94	90	175				28.73	70.6
		629.935										
B-1	5.0	633.2	1.60	1.40	93	90	175				31.87	78.3
2	5.0	636.3	1.50	1.30	95	91	176				30.89	75.9
3	5.0	639.286	1.30	1.10	96	92	175				28.73	70.6
		639.286										
C-1	5.0	642.5	1.50	1.30	96	92	174				30.84	75.8
2	5.0	645.6	1.50	1.30	97	92	175				30.86	75.8
3	5.0	648.511	1.30	1.10	97	92	175				28.73	70.6
		648.511										
D-1	5.0	651.7	1.60	1.40	96	90	174				31.85	78.3
2	5.0	655.0	1.60	1.40	97	91	174				31.85	78.3
3	5.0	658.037	1.40	1.20	98	92	175				29.82	73.3
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	37.326	1.210	1.267		93	175	13.8	5.2	-1.20	30.49	74.9
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.61	$V_{m(std)}$ =	35.812	$V_{w(std)}$ =	5.181	%M=	12.64
B_{ws} =	0.126	M_d =	30.42	M_s =	28.85	%EA=	32.13

STACK GAS VELOCITY =	74.9	AFPS	V_s
STACK GAS VELOCITY =	4,495	AFPM	
STACK GAS VOLUME =	571,183	DSCFM	Q_{std}
STACK GAS VOLUME =	794,292	ACFM	Q_a
ISOKINETIC RATIO =	93.8	%	

PARTICULATE EMISSIONS

Weight, mg =	28.4
GR/DSCF =	0.012
LBS/MMBTU =	**0.023**

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **3-8.5%** Date: 8/17/05 Start Time: 16:21
End Time: 17:28

DIAMETER OF NOZZLE:	0.185		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.87E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.70	P_{bar}	VOLUME OF MOISTURE:	111.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		658.508										
A-1	5.0	550.5	1.60	1.30	95	92	173				31.82	78.3
2	5.0	553.6	1.60	1.30	95	92	173	13.9	5.2	-1.20	31.82	78.3
3	5.0	556.404	1.40	1.10	96	92	172				29.75	73.1
		556.404										
B-1	5.0	559.4	1.50	1.20	96	92	173				30.81	75.8
2	5.0	562.3	1.50	1.20	98	93	172				30.79	75.7
3	5.0	565.156	1.30	1.00	98	93	171				28.64	70.4
		565.156										
C-	5.0	568.1	1.60	1.30	97	93	172				31.80	78.2
2	5.0	571.2	1.60	1.30	98	93	172				31.80	78.2
3	5.0	574.132	1.30	1.00	98	93	171				28.64	70.4
		574.132										
D-1	5.0	577.2	1.60	1.30	97	93	172				31.80	78.2
2	5.0	580.3	1.50	1.20	98	93	172				30.79	75.7
3	5.0	694.741	1.30	1.00	98	93	171				28.64	70.4
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	36.233	1.217	1.183		95	172	13.9	5.2	-1.20	30.59	75.2
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.61	$V_{m(std)}$ =	34.657	$V_{w(std)}$ =	5.228	%M=	13.11
B_{ws} =	0.131	M_d =	30.43	M_s =	28.80	%EA=	32.18

STACK GAS VELOCITY = 75.2 AFPS V_s
STACK GAS VELOCITY = 4,513 AFPM
STACK GAS VOLUME = 572,992 DSCFM Q_{std}
STACK GAS VOLUME = 797,534 ACFM Q_a
ISOKINETIC RATIO = 95.5 %

PARTICULATE EMISSIONS
Weight, mg = 30.6
GR/DSCF = 0.014
LBS/MMBTU = **0.025**

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1182
Plant	SPURLOCK	Nozzle No.	04	Initial Leak (Samp.)	0.000@8"
Location	U-3 STACK	Nozzle Dn.	0.190	Initial Leak (Pitot)	OK@5"
Test	M-5	TC No.	CAM-07		OK@6"
Run	4	P_B	29.70		
Date	8-17-05	Ambient Temp	88	Final Leak (Samp.)	0.000@6"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK@5"
ΔH	1.55 | Y: 1.01				OK@6"

K=0.91

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1325		583.421									
D-1		5	586.7	1.6	1.4	174	245	253	90	89	66	1.0
2		10	589.9	1.6	1.4	175	250	257	91	89	62	1.0
3	1340	15	592.917	1.4	1.2	175	245	249	92	87	61	1.0
	1343		592.917									
C-1		20	596.0	1.5	1.3	174	245	254	92	88	65	1.0
2		25	599.1	1.5	1.3	175	249	259	92	88	62	1.0
3	1358	30	602.095	1.3	1.1	175	247	255	94	89	61	1.0
	1401		602.095									
B-1		35	605.3	1.6	1.4	174	249	254	95	90	66	1.0
2		40	608.5	1.6	1.4	175	249	253	95	90	64	1.0
3	1416	45	611.403	1.3	1.1	175	246	250	95	90	60	1.5
	1419		611.403									
A-1		50	614.4	1.5	1.3	175	250	254	95	91	65	1.5
2		55	617.6	1.5	1.3	175	252	258	96	91	63	1.5
3	1434	60	620.460	1.3	1.1	175	249	257	96	91	63	1.5

COMMENTS: IMPS 1 186
2 115
3 6

GEL 250
256

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/17/05
SAMPLING TIME: (24 HR CLOCK) 1325 - 1434
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 88
TECHNICIAN: Love / Hale / Taylor

Run 1
8%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = 20.9 − %O2 / %CO2	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.8		13.8		13.8		13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.3	19.1	5.3	19.1	5.3	5.3	Fuel Type	Fo (calc)
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ok

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	186	115	6				256	
INITIAL (ml)	100	100	0				250	
NET (ml)	86	15	6				6	113.0
TOTALS								113.0

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C-1182			WEIGHED BY	BEAKER NO.	21		Blank	WEIGHED BY
FINAL WEIGHT	1.0432			MT	FINAL WEIGHT	108.6936			MT
INITIAL WEIGHT	1.0227			CA	INITIAL WEIGHT	108.6889			
DIFFERENCE	0.0205			MT	DIFFERENCE	0.0047			
PARTICULATE CATCH	20.5			MT	PARTICULATE CATCH	4.7		✓	

TOTAL PARTICULATE CATCH (mg) 25.2

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1184
Plant	SPURLOCK	Nozzle No.	41	Initial Leak (Samp.)	0.000 @ 7"
Location	U-3 STACK	Nozzle Dn.	0.190	Initial Leak (Pitot)	OK @ 5"
Test	M-5	TC No.	CAM-07		OK @ 6"
Run	5	P_B	29.70		
Date	8-17-05	Ambient Temp	88	Final Leak (Samp.)	0.000 @ 6"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK @ 6"
ΔH	1.55 | Y, 1.01				OK @ 6"

K = .91

POINT	TIME ACTUAL	RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1452		620.711									
A-1		5	623.9	1.5	1.3	175	243	247	93	90	64	1.0
2		10	627.0	1.5	1.3	175	243	248	94	90	62	1.0
3	1507	15	629.935	1.3	1.1	175	248	251	94	90	61	1.0
	1510		629.935									
B-1		20	633.2	1.6	1.4	175	250	253	93	90	65	1.0
2		25	636.3	1.5	1.3	176	251	254	95	91	62	1.0
3	1525	30	639.286	1.3	1.1	175	247	251	96	92	61	1.0
	1528		639.286									
C-1		35	642.5	1.5	1.3	174	247	255	96	92	66	1.0
2		40	645.6	1.5	1.3	175	245	255	97	92	64	1.0
3	1543	45	648.511	1.3	1.1	175	245	250	97	92	63	1.0
	1546		648.511									
D-1		50	651.7	1.6	1.4	174	246	252	96	90	63	1.0
2		55	655.0	1.6	1.4	174	251	253	97	91	60	1.0
3	1601	60	658.037	1.4	1.2	175	249	256	98	92	60	1.0

COMMENTS: IMPS 1 186
2 116
3 2

GEL 250 256

97

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/17/05
SAMPLING TIME: (24 HR CLOCK) 1452 - 1601
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 88
TECHNICIAN: Lovel Hale / Taylor

Run 2
8%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.8		13.8		13.8		13.8		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.0	5.2	19.0	5.2	19.0	5.2	5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ok

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	186	116	2				256	
INITIAL (ml)	100	100	0				250	
NET (ml)	86	16	2				6	110.0
TOTALS								110.0

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C-1184			WEIGHED BY	BEAKER NO.	20		Blank	WEIGHED BY
FINAL WEIGHT	1.0183			MT	FINAL WEIGHT	108.6353			MT
INITIAL WEIGHT	0.9944			CA	INITIAL WEIGHT	108.6308			
DIFFERENCE	0.0239			MT	DIFFERENCE	0.0045			
PARTICULATE CATCH	23.9			MT	PARTICULATE CATCH	4.5		0	

TOTAL PARTICULATE CATCH (mg) 28.4

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1185
Plant	SPURLOCK	Nozzle No.	102	Initial Leak (Samp.)	0.000@7"
Location	U-3 STACK	Nozzle Dn.	0.185	Initial Leak (Pitot)	OK @4"
Test	M-5	TC No.	CAM-07		OK @5"
Run	6	P_B	29.70		
Date	8-17-05	Ambient Temp	90	Final Leak (Samp.)	0.000@4"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK@5"
Δ H	1.55 | Y 1.01				OK@6"

K=.82

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1621		658.508									
D-1		5	661.7	1.6	1.3	173	246	254	95	92	65	1.0
2		10	664.8	1.6	1.3	173	248	253	95	92	63	1.0
3	1636	15	667.762	1.4	1.1	172	247	256	96	92	62	1.0
	1638		667.762									
C-1		20	670.7	1.5	1.2	173	249	250	96	92	64	1.0
2		25	673.8	1.5	1.2	172	248	251	98	93	62	1.0
3	1653	30	676.634	1.3	1.0	171	248	252	98	93	61	1.0
	1656		676.634									
B-1		35	679.7	1.6	1.3	172	250	255	97	93	64	1.0
2		40	682.9	1.6	1.3	172	248	253	98	93	62	1.0
3	1711	45	685.765	1.3	1.0	171	247	253	98	93	61	1.0
	1713		685.765									
A-1		50	688.8	1.6	1.3	172	251	256	97	93	65	1.0
2		55	691.9	1.5	1.2	172	248	255	98	93	62	1.0
3	1728	60	694.741	1.3	1.0	171	249	253	98	93	60	1.0

COMMENTS: IMPS 1 188 GEL 250
255
2 116
3 2

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spurlock DATE: 8/17/05
SAMPLING TIME: (24 HR CLOCK) 1621 - 1728
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 90
TECHNICIAN: Love / Hale / Taylor

Run 3
8%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	13.9		13.9		13.9		13.9		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.1	5.2	19.1	5.2	19.1	5.2	5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	188	116	2				255	
INITIAL (ml)	100	100	0				250	
NET (ml)	88	16	2				5	111.0
TOTALS								111.0

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1185			WEIGHED BY
FINAL WEIGHT	1.0095			MT
INITIAL WEIGHT	0.9942			CA
DIFFERENCE	0.0153			MT
PARTICULATE CATCH	15.3			MT

PROBE/NOZZLE WASH

BEAKER NO.	25		Blank	WEIGHED BY
	103.6089			
FINAL WEIGHT	~~103.80~~			MT
INITIAL WEIGHT	103.5936			
DIFFERENCE	0.0153			
PARTICULATE CATCH	15.3		0	

TOTAL PARTICULATE CATCH (mg) 30.6

Site Name: UNIT03 Run 1 8%

Data Averaging Type: 1m

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Time of Report: 08/18/05 09:10

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	13:26	8.5	286.2	3.883E+07	0.149	0.072	0.09	4.79	4.49
	13:27	8.4	286.5	3.885E+07	0.147	0.072	0.09	4.74	4.44
	13:28	8.8	286.4	3.881E+07	0.152	0.073	0.08	4.85	4.55
	13:29	8.5	286.0	3.872E+07	0.161	0.072	0.08	4.80	4.42
	13:30	8.4	285.8	3.870E+07	0.137	0.070	0.08	4.72	4.36
	13:31	8.6	285.5	3.874E+07	0.174	0.073	0.09		
	13:32	8.6	285.3	3.878E+07	0.171	0.072			
	13:33	8.9	285.4	3.876E+07				4.80	
	13:34	8.9							

Run 1 8%

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 09:10

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	13:26	8.5	286.2	3.883E+07	0.149	0.072	0.09	4.79	4.49
	13:27	8.4	286.5	3.885E+07	0.147	0.072	0.09	4.74	4.44
	13:28	8.8	286.4	3.881E+07	0.152	0.073	0.08	4.85	4.55
	13:29	8.5	286.0	3.872E+07	0.161	0.072	0.08	4.80	4.42
	13:30	8.4	285.8	3.870E+07	0.137	0.070	0.08	4.72	4.36
	13:31	8.6	285.5	3.874E+07	0.174	0.073	0.09	4.80	4.47
	13:32	8.6	285.3	3.878E+07	0.171	0.072	0.08	4.79	4.44
	13:33	8.9	285.4	3.876E+07	0.167	0.074	0.09	4.84	4.44
	13:34	8.9	285.6	3.878E+07	0.162	0.074	0.09	4.85	4.48
	13:35	8.6	286.1	3.895E+07	0.158	0.074	0.08	4.81	4.43
	13:36	8.5	286.1	3.905E+07	0.160	0.073	0.08	4.85	4.47
	13:37	8.5	286.3	3.901E+07	0.171	0.081	0.08	4.76	4.34
	13:38	8.9	286.5	3.896E+07	0.175	0.077	0.08	4.88	4.52
	13:39	8.3	286.9	3.894E+07	0.148	0.074	0.08	4.74	4.33
	13:40	8.6	286.8	3.892E+07	0.137	0.073	0.09	4.88	4.53
	13:41	8.2	286.5	3.895E+07	0.139	0.073	0.08	4.75	4.48
	13:42	8.7	286.5	3.899E+07	0.130	0.073	0.08	4.83	4.48
	13:43	8.1	286.4	3.895E+07	0.119	0.072	0.08	4.73	4.32
	13:44	8.7	286.0	3.895E+07	0.132	0.073	0.08	4.87	4.49
	13:45	8.8	285.9	3.895E+07	0.133	0.074	0.08	4.87	4.54
	13:46	8.9	286.2	3.906E+07	0.121	0.073	0.09	4.83	4.61
	13:47	8.9	286.2	3.909E+07	0.096	0.071	0.09	4.88	4.54
	13:48	8.3	286.2	3.901E+07	0.094	0.073	0.09	4.76	4.39
	13:49	8.9	286.0	3.892E+07	0.089	0.071	0.09	4.87	4.53
	13:50	8.3	285.8	3.893E+07	0.113	0.074	0.09	4.75	4.38
	13:51	8.6	285.8	3.896E+07	0.102	0.074	0.09	4.77	4.39
	13:52	9.0	285.5	3.897E+07	0.091	0.073	0.09	4.95	4.58
	13:53	8.6	284.9	3.905E+07	0.098	0.072	0.09	4.81	4.41
	13:54	8.9	284.6	3.895E+07	0.092	0.073	0.09	4.87	4.52
	13:55	8.4	284.5	3.886E+07	0.106	0.075	0.09	4.80	4.43
	13:56	8.6	284.2	3.892E+07	0.103	0.072	0.09	4.82	4.45
	13:57	8.2	284.2	3.904E+07	0.102	0.073	0.09	4.71	4.30
	13:58	8.7	284.2	3.921E+07	0.110	0.075	0.09	4.83	4.44
	13:59	8.6	284.2	3.911E+07	0.101	0.074	0.09	4.81	4.40
	14:00	8.3	284.2	3.899E+07	0.099	0.075	0.09	4.75	4.45
	14:01	8.6	284.2	3.894E+07	0.100	0.074	0.09	4.84	4.52
	14:02	8.4	284.3	3.891E+07	0.091	0.074	0.09	4.87	4.50
	14:03	8.1	284.6	3.895E+07	0.103	0.074	0.09	4.79	4.40
	14:04	8.1	284.6	3.895E+07	0.101	0.074	0.09	4.75	4.43
	14:05	8.2	284.5	3.887E+07	0.093	0.074	0.09	4.80	4.54
	14:06	8.4	284.2	3.883E+07	0.109	0.074	0.09	4.87	4.63
	14:07	8.3	284.3	3.887E+07	0.113	0.075	0.08	4.77	4.44
	14:08	8.4	284.7	3.882E+07	0.119	0.074	0.09	4.84	4.59
	14:09	8.7	285.2	3.874E+07	0.104	0.072	0.09	4.81	4.54
	14:10	8.6	285.6	3.874E+07	0.109	0.072	0.09	4.84	4.56
	14:11	8.4	285.4	3.884E+07	0.114	0.074	0.09	4.88	4.57
	14:12	8.7	285.4	3.893E+07	0.096	0.072	0.09	4.82	4.46
	14:13	8.6	285.5	3.883E+07	0.096	0.074	0.09	4.84	4.51
	14:14	8.4	285.6	3.891E+07	0.117	0.072	0.09	4.78	4.44
	14:15	8.7	285.2	3.902E+07	0.118	0.073	0.09	4.94	4.61

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Time of Report: 08/18/05 09:10

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	14:16	8.1	284.8	3.898E+07	0.111	0.074	0.08	4.80	4.44
	14:17	8.3	284.6	3.893E+07	0.128	0.076	0.08	4.76	4.37
	14:18	8.7	284.7	3.898E+07	0.125	0.071	0.08	4.85	4.45
	14:19	8.4	285.0	3.900E+07	0.123	0.073	0.08	4.86	4.60
	14:20	8.2	285.0	3.898E+07	0.129	0.074	0.08	4.78	4.52
	14:21	8.6	285.1	3.893E+07	0.115	0.072	0.08	4.91	4.58
	14:22	8.3	285.2	3.892E+07	0.122	0.074	0.08	4.79	4.37
	14:23	8.6	284.8	3.910E+07	0.120	0.072	0.08	4.90	4.56
	14:24	8.4	284.9	3.923E+07	0.116	0.073	0.08	4.84	4.45
	14:25	8.5	285.4	3.926E+07	0.125	0.073	0.08	4.84	4.50
	14:26	8.4	285.5	3.916E+07	0.140	0.074	0.08	4.87	4.49
	14:27	8.4	285.9	3.917E+07	0.127	0.074	0.08	4.84	4.43
	14:28	8.6	286.1	3.925E+07	0.120	0.076	0.08	4.90	4.59
	14:29	8.5	286.0	3.925E+07	0.115	0.073	0.08	4.87	4.59
	14:30	8.5	285.6	3.918E+07	0.100	0.074	0.08	4.83	4.50
	14:31	8.7	285.4	3.903E+07	0.108	0.072	0.09	4.91	4.54
	14:32	8.3	285.4	3.907E+07	0.095	0.072	0.09	4.79	4.37
	14:33	8.4	285.4	3.914E+07	0.095	0.074	0.08	4.82	4.47
	14:34	8.4	285.4	3.907E+07	0.115	0.073	0.08	4.85	4.52
Average =		8.5	285.4	3.896E+07	0.121	0.073	0.09	4.82	4.48
Maximum =		9.0	286.9	3.926E+07	0.175	0.081	0.09	4.95	4.63
Minimum =		8.1	284.2	3.870E+07	0.089	0.070	0.08	4.71	4.30
Possible Values =		69	69	69	69	69	69	69	69
luded Values =		69	69	69	69	69	69	69	69
Total =		587.8	19693.0	2.688E+09	8.347	5.062	5.88	332.76	308.89

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

Run 2 8%

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 09:11

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	14:53	8.4	284.6	3.930E+07	0.089	0.075	0.09	4.86	4.47
	14:54	8.3	284.7	3.929E+07	0.085	0.073	0.09	4.82	4.45
	14:55	8.7	285.0	3.913E+07	0.087	0.072	0.09	4.96	4.57
	14:56	8.5	285.0	3.903E+07	0.086	0.072	0.09	4.90	4.59
	14:57	8.5	284.8	3.910E+07	0.084	0.072	0.09	4.87	4.52
	14:58	8.9	284.7	3.924E+07	0.085	0.072	0.09	4.94	4.58
	14:59	8.6	284.9	3.937E+07	0.069	0.072	0.09	4.90	4.52
	15:00	8.5	284.5	3.929E+07	0.082	0.073	0.09	4.86	4.50
	15:01	8.8	284.0	3.914E+07	0.072	0.073	0.09	4.96	4.62
	15:02	8.4	283.6	3.910E+07	0.061	0.072	0.09	4.87	4.52
	15:03	8.8	283.5	3.916E+07	0.069	0.074	0.09	4.94	4.62
	15:04	8.2	283.5	3.921E+07	0.068	0.074	0.09	4.81	4.46
	15:05	8.8	283.3	3.911E+07	0.062	0.073	0.09	4.96	4.58
	15:06	8.3	283.3	3.910E+07	0.063	0.072	0.09	4.87	4.59
	15:07	8.9	283.6	3.923E+07	0.079	0.074	0.09	5.00	4.70
	15:08	8.6	283.3	3.925E+07	0.085	0.074	0.09	4.89	4.53
	15:09	8.5	283.0	3.932E+07	0.072	0.073	0.09	4.90	4.51
	15:10	8.7	283.2	3.927E+07	0.073	0.074	0.09	5.00	4.65
	15:11	8.4	283.3	3.924E+07	0.090	0.075	0.09	4.84	4.58
	15:12	9.1	283.2	3.924E+07	0.095	0.074	0.09	5.03	4.76
	15:13	8.6	283.4	3.912E+07	0.084	0.075	0.09	4.95	4.68
	15:14	8.7	283.4	3.908E+07	0.089	0.073	0.09	4.93	4.67
	15:15	9.1	283.4	3.916E+07	0.079	0.072	0.09	5.02	4.73
	15:16	8.9	283.4	3.909E+07	0.083	0.073	0.09	5.02	4.73
	15:17	8.4	283.4	3.906E+07	0.079	0.073	0.09	4.94	4.64
	15:18	8.7	283.4	3.920E+07	0.070	0.072	0.09	5.01	4.74
	15:19	9.0	283.4	3.915E+07	0.067	0.072	0.09	5.02	4.73
	15:20	9.2	283.4	3.902E+07	0.069	0.072	0.09	5.07	4.74
	15:21	8.9	283.3	3.899E+07	0.065	0.071	0.09	5.04	4.70
	15:22	8.7	283.2	3.911E+07	0.074	0.072	0.09	4.97	4.65
	15:23	9.2	283.5	3.909E+07	0.075	0.072	0.09	5.09	4.80
	15:24	8.5	283.8	3.898E+07	0.074	0.073	0.09	5.02	4.77
	15:25	8.7	284.0	3.904E+07	0.091	0.073	0.09	5.01	4.74
	15:26	9.3	283.8	3.910E+07	0.080	0.072	0.09	5.14	4.87
	15:27	9.0	283.4	3.910E+07	0.059	0.071	0.09	5.08	4.76
	15:28	8.7	282.9	3.905E+07	0.062	0.074	0.09	5.04	4.74
	15:29	8.6	282.7	3.897E+07	0.066	0.072	0.09	5.05	4.77
	15:30	8.8	282.7	3.903E+07	0.056	0.072	0.09	5.16	4.89
	15:31	8.6	282.8	3.907E+07	0.050	0.071	0.09	5.05	4.78
	15:32	8.8	283.0	3.906E+07	0.052	0.071	0.09	5.13	4.82
	15:33	8.2	283.0	3.906E+07	0.073	0.071	0.09	4.99	4.67
	15:34	9.0	283.3	3.903E+07	0.077	0.072	0.09	5.15	4.81
	15:35	8.4	283.9	3.908E+07	0.088	0.073	0.08	5.03	4.71
	15:36	8.8	284.2	3.912E+07	0.099	0.071	0.08	5.14	4.81
	15:37	8.5	284.1	3.910E+07	0.091	0.072	0.08	5.08	4.73
	15:38	8.7	283.8	3.912E+07	0.079	0.071	0.09	5.10	4.79
	15:39	9.1	283.8	3.915E+07	0.086	0.071	0.08	5.12	4.88
	15:40	9.3	284.2	3.914E+07	0.090	0.071	0.09	5.18	4.93
	15:41	8.6	284.2	3.917E+07	0.092	0.072	0.08	5.05	4.79
	15:42	9.2	284.3	3.923E+07	0.097	0.071	0.08	5.19	4.95

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Time of Report: 08/18/05 09:11

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	15:43	8.5	284.7	3.923E+07	0.106	0.071	0.08	5.06	4.81
	15:44	9.3	285.7	3.917E+07	0.119	0.070	0.08	5.26	4.99
	15:45	8.5	286.5	3.918E+07	0.101	0.069	0.08	5.03	4.69
	15:46	9.1	286.4	3.920E+07	0.100	0.070	0.08	5.17	4.82
	15:47	8.5	286.8	3.926E+07	0.096	0.068	0.08	5.13	4.78
	15:48	8.2	287.4	3.937E+07	0.100	0.068	0.09	5.02	4.72
	15:49	8.7	287.6	3.934E+07	0.115	0.068	0.09	5.20	4.93
	15:50	8.4	287.3	3.923E+07	0.128	0.070	0.08	5.08	4.83
	15:51	9.1	287.3	3.919E+07	0.127	0.070	0.08	5.28	5.05
	15:52	8.7	286.9	3.918E+07	0.128	0.070	0.09	5.07	4.77
	15:53	9.2	286.1	3.923E+07	0.120	0.070	0.08	5.21	4.90
	15:54	8.4	285.9	3.922E+07	0.126	0.070	0.08	5.06	4.78
	15:55	9.0	286.0	3.908E+07	0.126	0.069	0.08	5.23	4.99
	15:56	8.7	285.9	3.911E+07	0.124	0.070	0.08	5.16	4.92
	15:57	9.1	286.0	3.912E+07	0.132	0.070	0.08	5.22	5.00
	15:58	8.9	285.9	3.899E+07	0.139	0.070	0.09	5.28	5.05
	15:59	9.0	286.1	3.899E+07	0.116	0.069	0.09	5.21	4.95
	16:00	9.8	286.1	3.900E+07	0.130	0.070	0.08	5.36	5.09
	16:01	8.7	286.0	3.900E+07	0.128	0.068	0.08	5.16	4.92
Average =		8.8	284.4	3.914E+07	0.089	0.072	0.09	5.05	4.74
Maximum =		9.8	287.6	3.937E+07	0.139	0.075	0.09	5.36	5.09
Minimum =		8.2	282.7	3.897E+07	0.050	0.068	0.08	4.81	4.45
Possible Values =		69	69	69	69	69	69	69	69
cluded Values =		69	69	69	69	69	69	69	69
Total =		603.8	19625.0	2.701E+09	6.112	4.945	5.96	348.14	327.32

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

Run 3 8%

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 09:13

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	16:22	8.6	287.1	3.906E+07	0.161	0.071	0.08	5.30	5.12
	16:23	8.8	286.7	3.903E+07	0.150	0.068	0.08	5.35	5.13
	16:24	8.4	286.9	3.911E+07	0.150	0.067	0.08	5.29	5.05
	16:25	8.8	287.0	3.916E+07	0.157	0.068	0.08	5.36	5.08
	16:26	8.3	287.7	3.913E+07	0.135	0.070	0.08	5.27	5.03
	16:27	8.2	288.7	3.917E+07	0.167	0.071	0.08	5.21	5.00
	16:28	8.5	289.2	3.915E+07	0.182	0.069	0.08	5.28	5.12
	16:29	8.5	289.2	3.911E+07	0.191	0.071	0.08	5.32	5.23
	16:30	8.2	289.2	3.912E+07	0.190	0.070	0.08	5.28	5.20
	16:31	8.8	289.2	3.911E+07	0.173	0.070	0.08	5.39	5.32
	16:32	9.1	289.1	3.909E+07	0.155	0.068	0.08	5.44	5.42
	16:33	8.4	288.9	3.907E+07	0.164	0.068	0.08	5.31	5.16
	16:34	8.9	289.2	3.916E+07	0.161	0.068	0.08	5.45	5.32
	16:35	8.2	289.2	3.914E+07	0.184	0.069	0.08	5.23	5.09
	16:36	8.6	289.3	3.913E+07	0.172	0.069	0.08	5.41	5.31
	16:37	8.4	289.5	3.911E+07	0.203	0.070	0.08	5.29	5.25
	16:38	9.0	289.1	3.905E+07	0.211	0.070	0.08	5.47	5.44
	16:39	8.2	288.8	3.900E+07	0.202	0.069	0.08	5.20	5.14
	16:40	9.1	288.7	3.901E+07	0.200	0.068	0.08	5.43	5.35
	16:41	8.3	288.2	3.904E+07	0.183	0.069	0.08	5.29	5.16
	16:42	8.7	287.7	3.897E+07	0.182	0.069	0.08	5.42	5.28
	16:43	8.3	287.6	3.904E+07	0.181	0.068	0.08	5.29	5.13
	16:44	8.4	287.2	3.905E+07	0.183	0.067	0.08	5.42	5.26
	16:45	8.2	286.8	3.899E+07	0.182	0.068	0.08	5.27	5.12
	16:46	8.6	286.7	3.898E+07	0.172	0.066	0.08	5.37	5.25
	16:47	8.4	286.6	3.898E+07	0.181	0.066	0.08	5.32	5.29
	16:48	8.5	286.8	3.910E+07	0.190	0.068	0.08	5.38	5.37
	16:49	8.5	286.8	3.918E+07	0.205	0.070	0.08	5.32	5.24
	16:50	8.9	286.9	3.908E+07	0.195	0.068	0.08	5.43	5.31
	16:51	8.4	287.4	3.894E+07	0.179	0.068	0.08	5.41	5.28
	16:52	8.1	287.6	3.896E+07	0.208	0.069	0.08	5.27	5.21
	16:53	9.0	287.3	3.903E+07	0.225	0.069	0.08	5.46	5.38
	16:54	8.3	287.3	3.911E+07	0.232	0.072	0.08	5.28	5.18
	16:55	8.5	287.5	3.908E+07	0.227	0.069	0.08	5.39	5.26
	16:56	8.4	288.2	3.903E+07	0.231	0.070	0.08	5.31	5.17
	16:57	8.6	288.8	3.906E+07	0.215	0.068	0.08	5.34	5.19
	16:58	8.7	288.8	3.917E+07	0.198	0.068	0.08	5.41	5.21
	16:59	8.4	288.8	3.917E+07	0.204	0.067	0.08	5.36	5.12
	17:00	8.1	288.9	3.910E+07	0.200	0.068	0.08	5.27	5.04
	17:01	8.6	289.1	3.912E+07	0.206	0.068	0.08	5.41	5.22
	17:02	8.1	288.9	3.912E+07	0.226	0.069	0.08	5.29	5.18
	17:03	8.9	289.2	3.914E+07	0.205	0.067	0.08	5.44	5.39
	17:04	8.1	289.2	3.915E+07	0.197	0.068	0.08	5.20	5.18
	17:05	8.7	289.1	3.913E+07	0.216	0.069	0.08	5.38	5.30
	17:06	8.4	288.7	3.912E+07	0.212	0.067	0.08	5.37	5.30
	17:07	8.8	288.7	3.905E+07	0.203	0.067	0.08	5.40	5.36
	17:08	8.4	289.1	3.907E+07	0.192	0.067	0.08	5.36	5.29
	17:09	8.2	288.8	3.924E+07	0.198	0.068	0.08	5.35	5.25
	17:10	8.2	288.7	3.925E+07	0.193	0.067	0.08	5.26	5.22
	17:11	8.7	288.3	3.918E+07	0.209	0.067	0.08	5.47	5.42

Plant Name: EKSP

General Average Report

Reporting Period: 08/17/2005 to 08/17/2005

Site Name: UNIT03

Time of Report: 08/18/05 09:13

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/17/05	17:12	8.0	287.8	3.910E+07	0.206	0.067	0.08	5.23	5.14
	17:13	9.0	287.4	3.897E+07	0.212	0.068	0.08	5.48	5.41
	17:14	8.4	287.2	3.904E+07	0.259	0.071	0.08	5.29	5.21
	17:15	8.9	287.6	3.910E+07	0.249	0.069	0.08	5.40	5.32
	17:16	8.6	287.5	3.908E+07	0.247	0.067	0.08	5.34	5.25
	17:17	8.6	288.3	3.900E+07	0.224	0.067	0.08	5.40	5.28
	17:18	8.1	289.6	3.894E+07	0.223	0.067	0.08	5.26	5.10
	17:19	8.4	290.2	3.896E+07	0.253	0.066	0.08	5.36	5.22
	17:20	8.5	290.0	3.906E+07	0.248	0.066	0.08	5.30	5.23
	17:21	8.9	289.8	3.913E+07	0.244	0.066	0.08	5.48	5.42
	17:22	8.0	289.7	3.911E+07	0.248	0.067	0.08	5.24	5.17
	17:23	9.4	289.7	3.906E+07	0.233	0.066	0.08	5.50	5.45
	17:24	8.4	290.0	3.903E+07	0.222	0.066	0.08	5.31	5.23
	17:25	8.8	290.1	3.898E+07	0.230	0.068	0.08	5.44	5.37
	17:26	8.5	290.3	3.906E+07	0.222	0.068	0.08	5.33	5.35
	17:27	8.8	290.2	3.923E+07	0.221	0.067	0.08	5.39	5.36
	17:28	8.7	289.8	3.924E+07	0.223	0.069	0.08	5.35	5.28
Average =		8.5	288.5	3.908E+07	0.202	0.068	0.08	5.35	5.24
Maximum =		9.4	290.3	3.925E+07	0.259	0.072	0.08	5.50	5.45
Minimum =		8.0	286.6	3.894E+07	0.135	0.066	0.08	5.20	5.00
Possible Values =		67	67	67	67	67	67	67	67
Included Values =		67	67	67	67	67	67	67	67
Total =		571.6	19327.9	2.619E+09	13.504	4.570	5.40	358.34	351.11

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

6% Opacity

Catalyst Air Management, Inc.

Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **1-6%** Date: 8/18/05 Start Time: 8:00
End Time: 9:09

DIAMETER OF NOZZLE:	0.190		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.97E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	111.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		695.804										
A-1	5.0	699.0	1.60	1.40	86	85	171				31.77	78.5
2	5.0	702.2	1.60	1.40	86	85	172	14.0	5.2	-1.20	31.80	78.5
3	5.0	705.105	1.30	1.10	87	84	171				28.64	70.7
		705.105										
B-1	5.0	708.3	1.60	1.40	88	85	171				31.77	78.5
2	5.0	711.5	1.60	1.40	89	86	172				31.80	78.5
3	5.0	714.339	1.30	1.10	90	86	172				28.66	70.8
		714.339										
C-1	5.0	717.4	1.50	1.30	90	87	171				30.77	76.0
2	5.0	720.5	1.50	1.30	91	87	172				30.79	76.0
3	5.0	723.392	1.30	1.10	91	87	172				28.66	70.8
		723.392										
D-1	5.0	726.5	1.60	1.40	92	87	171				31.77	78.5
2	5.0	729.8	1.60	1.40	92	87	172				31.80	78.5
3	5.0	732.718	1.30	1.10	93	88	170				28.62	70.7
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	36.914	1.217	1.283		88	171	14.0	5.2	-1.20	30.57	75.5
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.31	$V_{m(std)}$ =	35.405	$V_{w(std)}$ =	5.228	%M=	12.87
B_{ws} =	0.129	M_d =	30.45	M_s =	28.85	%EA=	32.24

STACK GAS VELOCITY =	75.5	AFPS	V_s
STACK GAS VELOCITY =	4,530	AFPM	
STACK GAS VOLUME =	571,374	DSCFM	Q_{std}
STACK GAS VOLUME =	800,455	ACFM	Q_a
ISOKINETIC RATIO =	92.7	%	

PARTICULATE EMISSIONS

Weight, mg =	16.5
GR/DSCF =	0.007
LBS/MMBTU =	**0.013**

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **2-6%** Date: 8/18/05 Start Time: 9:40
End Time: 10:49

DIAMETER OF NOZZLE:	0.185		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.87E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	111.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		732.964										
A-1	5.0	736.1	1.60	1.30	90	88	171				31.77	78.5
2	5.0	739.2	1.60	1.30	91	88	172	14.0	5.2	-1.20	31.80	78.6
3	5.0	742.109	1.30	1.00	91	88	172				28.66	70.8
		742.109										
B-1	5.0	745.0	1.50	1.20	92	89	172				30.79	76.1
2	5.0	748.0	1.50	1.20	93	89	173				30.81	76.2
3	5.0	750.821	1.30	1.00	94	89	173				28.69	70.9
		750.821										
C-1	5.0	753.9	1.60	1.30	93	90	172				31.80	78.6
2	5.0	757.0	1.60	1.30	94	90	173				31.82	78.6
3	5.0	759.839	1.30	1.00	95	89	173				28.69	70.9
		759.839										
D-1	5.0	762.9	1.60	1.30	95	90	172				31.80	78.6
2	5.0	766.0	1.60	1.30	95	90	173				31.82	78.6
3	5.0	769.068	1.30	1.00	95	90	172				28.66	70.8
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	36.104	1.217	1.183		91	172	14.0	5.2	-1.20	30.59	75.6
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.31	$V_{m(std)}$ =	34.413	$V_{w(std)}$ =	5.228	%M=	13.19
B_{ws} =	0.132	M_d =	30.45	M_s =	28.81	%EA=	32.24

STACK GAS VELOCITY =	75.6	AFPS	V_s
STACK GAS VELOCITY =	4,536	AFPM	
STACK GAS VOLUME =	569,240	DSCFM	Q_{std}
STACK GAS VOLUME =	801,586	ACFM	Q_a
ISOKINETIC RATIO =	95.4	%	

PARTICULATE EMISSIONS

Weight, mg =	16.5
GR/DSCF =	0.007
LBS/MMBTU =	**0.014**

Catalyst Air Management, Inc.
Method 5 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Stack

Run No: **3-6%** Date: 8/18/05 Start Time: 11:10
End Time: 12:22

DIAMETER OF NOZZLE:	0.190		STACK DIAMETER =	180	in
AREA OF NOZZLE:	1.97E-04	A_n	STACK AREA =	176.7	sq. ft.
BAROMETRIC PRESSURE:	29.40	P_{bar}	VOLUME OF MOISTURE:	110.0	V_{lc}
GAS METER Y-FACTOR:	1.01	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		769.423										
A-1	5.0	772.6	1.60	1.40	93	90	171				31.77	78.5
2	5.0	775.9	1.60	1.40	93	90	172	14.0	5.2	-1.20	31.80	78.5
3	5.0	778.811	1.30	1.10	94	90	173				28.69	70.8
		778.811										
B-1	5.0	782.0	1.60	1.40	94	90	171				31.77	78.5
2	5.0	785.1	1.50	1.30	95	90	172				30.79	76.0
3	5.0	788.010	1.30	1.10	96	91	172				28.66	70.8
		788.010										
C-	5.0	790.0	1.50	1.30	96	91	171				30.77	76.0
2	5.0	794.2	1.50	1.30	96	92	172				30.79	76.0
3	5.0	797.077	1.30	1.10	97	91	172				28.66	70.8
		797.077										
D-1	5.0	800.2	1.60	1.40	96	92	171				31.77	78.5
2	5.0	803.5	1.60	1.40	97	92	172				31.80	78.5
3	5.0	806.431	1.30	1.10	97	92	172				28.66	70.8
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	37.008	1.213	1.275		93	172	14.0	5.2	-1.20	30.50	75.3
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.31	$V_{m(std)}$ =	35.158	$V_{w(std)}$ =	5.181	%M=	12.84
B_{ws} =	0.128	M_d =	30.45	M_s =	28.85	%EA=	32.24

STACK GAS VELOCITY =	75.3	AFPS	V_s
STACK GAS VELOCITY =	4,518	AFPM	
STACK GAS VOLUME =	569,763	DSCFM	Q_{std}
STACK GAS VOLUME =	798,411	ACFM	Q_a
ISOKINETIC RATIO =	92.3	%	

PARTICULATE EMISSIONS

Weight, mg =	17.7
GR/DSCF =	0.008
LBS/MMBTU =	**0.014**

CATALYST AIR MANAGEMENT, INC.
Air Quality Testing Services
2505 Byington Solway Road
Knoxville, TN 37931
(865) 531-0075
(865) 531-0750 Fax

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1186
Plant	SPURLOCK	Nozzle No.	41	Initial Leak (Samp.)	0.000 @ 8"
Location	U-3 STACK	Nozzle Dn.	0.190	Initial Leak (Pitot)	OK @ 5"
Test	M-5	TC No.	CAM-07		OK @ 6"
Run	1	P_B	29.40		
Date	8-18-05	Ambient Temp	81	Final Leak (Samp.)	0.005 @ 5"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK @ 6"
ΔH	1.55 | Y_1 1.01				OK @ 5"

K = .91

	POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
		800		695.804									
A	~~D~~-1		5	699.0	1.6	1.4	171	247	248	86	85	65	1.0
	2		10	702.2	1.6	1.4	172	244	245	86	85	61	1.0
	3	815	15	705.105	1.3	1.1	171	251	252	87	84	62	1.0
		818		705.105									
B	~~C~~-1		20	708.3	1.6	1.4	171	250	254	88	85	65	1.0
	2		25	711.5	1.6	1.4	172	250	254	89	86	62	1.0
	3	833	30	714.339	1.3	1.1	172	246	251	90	86	62	1.0
		836		714.339									
C	~~B~~-1		35	717.4	1.5	1.3	171	251	253	90	87	66	1.0
	2		40	720.5	1.5	1.3	172	246	253	91	87	64	1.0
	3	851	45	723.392	1.3	1.1	172	249	251	91	87	63	1.0
		854		723.392									
D	~~A~~-1		50	726.5	1.6	1.4	171	249	255	92	87	65	1.5
	2		55	729.8	1.6	1.4	172	254	254	92	87	63	1.5
	3	909	60	732.718	1.3	1.1	170	250	253	93	88	62	1.5

COMMENTS: IMPS 1 186
2 116
3 2

GEL 257 250

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spurlock DATE: 8/18/05
SAMPLING TIME: (24 HR CLOCK) 0800 - 0909
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 81
TECHNICIAN: Lowe / Hole / Taylor

Run 1
6%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = 20.9 − %O2 / %CO2	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	14.0		14.0		14.0		14.0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.2	5.2	19.2	5.2	19.2	5.2	5.2	Fuel Type	Fo (calc)
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 19.8 / 19.8 BUBBLER
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	186	116	2				257	
INITIAL (ml)	100	100	0				250	
NET (ml)	86	16	2				7	111.0
TOTALS								111.0

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C-1186			WEIGHED BY	BEAKER NO.	20		Blank	WEIGHED BY
FINAL WEIGHT	1.0166			MT	FINAL WEIGHT	108.6421			MT
INITIAL WEIGHT	1.0069			CA	INITIAL WEIGHT	108.6353			
DIFFERENCE	0.0097			MT	DIFFERENCE	0.0068			
PARTICULATE CATCH	9.7			MT	PARTICULATE CATCH	6.8		0	

TOTAL PARTICULATE CATCH (mg) 16.5

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1187
Plant	SPURLOCK	Nozzle No.	102	Initial Leak (Samp.)	0.000@6"
Location	U-3 STACK	Nozzle Dn.	0.185	Initial Leak (Pitot)	OK@5"
Test	M-5	TC No.	CAM-07		OK@4"
Run	2	P_B	29.40		
Date	8-18-05	Ambient Temp	85	Final Leak (Samp.)	0.002@4"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK@6"
ΔH	1.55 | Y 1.01				OK@5"

K = .82

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	940		732.964									
D-1		5	736.1	1.6	1.3	171	254	255	90	88	64	1.0
2		10	739.2	1.6	1.3	172	245	247	91	88	62	1.0
3	955	15	742.109	1.3	1.0	172	244	247	91	88	61	1.0
	958		742.109									
C-1		20	745.0	1.5	1.2	172	256	252	92	89	65	1.0
2		25	748.0	1.5	1.2	173	249	256	93	89	62	1.0
3	1013	30	750.821	1.3	1.0	173	252	258	94	89	61	1.0
	1016		750.821									
B-1		35	753.9	1.6	1.3	172	252	254	93	90	65	1.5
2		40	757.0	1.6	1.3	173	245	248	94	90	63	1.5
3	1031	45	759.839	1.3	1.0	173	251	253	95	89	62	1.5
	1034		759.839									
A-1		50	762.9	1.6	1.3	172	248	250	95	90	66	2.0
2		55	766.0	1.6	1.3	173	252	255	95	90	64	2.0
3	1049	60	769.068	1.3	1.0	172	247	255	95	90	61	2.0

COMMENTS: IMPS 1 188
2 116
3 2

GEL 255
250

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/18/05
SAMPLING TIME: (24 HR CLOCK) 0940 - 1049
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 85
TECHNICIAN: Love / Hale / Taylor

Run 2
6%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2	14.0		14.0		14.0		14.0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)	19.2	5.2	19.2	5.2	19.2	5.2	5.2	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK [illegible]
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 19.8 / 19.8 BUBBLER [illegible]
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER [illegible]

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	188	116	2				255	
INITIAL (ml)	100	100	0				250	
NET (ml)	88	16	2				5	111.0
TOTALS								111.0

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	C-1187			WEIGHED BY	BEAKER NO.	05		Blank	WEIGHED BY
FINAL WEIGHT	1.0221			MT	FINAL WEIGHT	103.1490			MT
INITIAL WEIGHT	1.0132			CA	INITIAL WEIGHT	103.1414			
DIFFERENCE	0.0089			MT	DIFFERENCE	0.0076			
PARTICULATE CATCH	8.9			MT	PARTICULATE CATCH	7.6		0	

TOTAL PARTICULATE CATCH (mg) 16.5

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 7	Filter Number	C-1188
Plant	SPURLOCK	Nozzle No.	#1	Initial Leak (Samp.)	0.000@7"
Location	U-3 STACK	Nozzle Dn.	0.190	Initial Leak (Pitot)	OK@5"
Test	M-5	TC No.	CAM-07		OK@6"
Run	3	P_B	29.40		
Date	8-18-05	Ambient Temp	89	Final Leak (Samp.)	0.000@5"
Meter Box	010	Static	-1.2	Final Leak (Pitot)	OK@6"
ΔH	1.55 | Y 1.01				OK@7"

K = .91

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1113		769.423									
A-1		5	772.6	1.6	1.4	171	243	249	93	90	64	1.0
2		10	775.9	1.6	1.4	172	247	249	93	90	62	1.0
3	1128	15	778.811	1.3	1.1	173	251	255	94	90	62	1.0
	1131		778.811									
B-1		20	782.0	1.6	1.4	171	248	251	94	90	65	1.0
2		25	785.1	1.5	1.3	172	250	253	95	90	63	1.0
3	1146	30	788.010	1.3	1.1	172	251	256	96	91	62	1.0
	1149		788.010									
C-1		35	791.0	1.5	1.3	171	245	248	96	91	66	1.0
2		40	794.2	1.5	1.3	172	249	255	96	92	63	1.0
3	1204	45	797.077	1.3	1.1	172	252	256	97	91	62	1.0
	1207		797.077									
D-1		50	800.2	1.6	1.4	171	249	256	96	92	65	1.5
2		55	803.5	1.6	1.4	172	251	257	97	92	63	1.5
3	1222	60	806.431	1.3	1.1	172	253	258	97	92	62	1.5

COMMENTS: IMPS 1 188
2 110
3 6

GEL 256 250

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 8/18/05
SAMPLING TIME: (24 HR CLOCK) 1113 – 1222
SAMPLING LOCATION: Unit 3
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/5 AMB. TEMP (°F) 89
TECHNICIAN: Love / Hale / Taylor

Run 3
6%

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2									
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)								Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 19.8 / 19.8 BUBBLER ✓
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.0 / 20.0 BUBBLER ✓

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	188	110	6				256	
INITIAL (ml)	100	100	0				250	
NET (ml)	88	10	6				6	110.0
TOTALS								110.0

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	C-1188			WEIGHED BY
FINAL WEIGHT	1.0195			MT
INITIAL WEIGHT	1.0046			CA
DIFFERENCE	~~.149~~ 0.0149			MT
PARTICULATE CATCH	14.9			MT

PROBE/NOZZLE WASH

BEAKER NO.	24		Blank	WEIGHED BY
FINAL WEIGHT	100.1301			MT
INITIAL WEIGHT	100.1273			
DIFFERENCE	0.0028			
PARTICULATE CATCH	2.8		0	

TOTAL PARTICULATE CATCH (mg) 17.7

Plant Name: EKSP

General Average Report

Reporting Period: 08/18/2005 to 08/18/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:00

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/18/05	08:01	6.5	284.1	3.818E+07	0.137	0.074	0.08	5.14	5.20
	08:02	6.1	284.2	3.821E+07	0.129	0.074	0.08	4.90	4.88
	08:03	5.8	284.3	3.822E+07	0.136	0.075	0.07	4.80	4.75
	08:04	6.5	284.4	3.810E+07	0.137	0.074	0.08	5.05	5.03
	08:05	6.6	284.2	3.813E+07	0.154	0.074	0.07	5.04	5.08
	08:06	6.3	284.1	3.822E+07	0.169	0.073	0.08	4.96	4.99
	08:07	5.8	284.1	3.818E+07	0.153	0.073	0.08	4.65	4.69
	08:08	5.9	283.9	3.820E+07	0.156	0.073	0.07	4.73	4.78
	08:09	6.4	284.2	3.824E+07	0.153	0.074	0.07	5.00	5.06
	08:10	6.4	284.2	3.823E+07	0.153	0.076	0.07	4.96	5.02
	08:11	6.4	284.2	3.821E+07	0.140	0.074	0.07	5.10	5.16
	08:12	6.2	284.2	3.824E+07	0.121	0.072	0.08	5.03	5.11
	08:13	6.3	284.3	3.822E+07	0.118	0.071	0.08	5.05	5.11
	08:14	6.7	284.5	3.822E+07	0.123	0.072	0.08	5.13	5.17
	08:15	6.2	284.3	3.821E+07	0.127	0.074	0.08	5.00	5.00
	08:16	6.8	284.4	3.821E+07	0.131	0.077	0.07	5.20	5.22
	08:17	6.2	283.8	3.818E+07	0.146	0.075	0.08	4.94	4.93
	08:18	6.5	283.8	3.819E+07	0.130	0.074	0.08	5.09	5.09
	08:19	6.5	283.6	3.820E+07	0.129	0.076	0.08	4.98	4.99
	08:20	6.5	282.9	3.814E+07	0.137	0.075	0.08	5.02	5.08
	08:21	6.6	282.0	3.820E+07	0.123	0.076	0.08	5.03	5.11
	08:22	6.3	281.2	3.828E+07	0.130	0.077	0.08	4.87	4.91
	08:23	7.0	281.5	3.822E+07	0.122	0.075	0.08	5.16	5.23
	08:24	6.4	281.6	3.822E+07	0.131	0.076	0.08	4.96	4.97
	08:25	6.5	282.0	3.815E+07	0.120	0.076	0.08	5.05	5.08
	08:26	6.6	282.2	3.799E+07	0.133	0.078	0.08	5.08	5.11
	08:27	6.1	282.3	3.809E+07	0.132	0.077	0.08	4.97	4.97
	08:28	7.1	282.4	3.826E+07	0.127	0.078	0.08	5.19	5.23
	08:29	6.4	282.4	3.826E+07	0.124	0.076	0.08	4.95	4.89
	08:30	6.8	282.1	3.818E+07	0.129	0.076	0.08	5.11	5.11
	08:31	6.9	282.0	3.821E+07	0.131	0.075	0.07	5.12	5.14
	08:32	6.5	282.2	3.821E+07	0.127	0.076	0.08	4.98	4.92
	08:33	7.0	281.7	3.810E+07	0.134	0.078	0.08	5.25	5.22
	08:34	6.5	281.1	3.809E+07	0.131	0.076	0.08	4.98	4.94
	08:35	6.2	281.2	3.812E+07	0.109	0.074	0.08	4.84	4.86
	08:36	6.7	281.6	3.810E+07	0.116	0.075	0.08	5.12	5.15
	08:37	6.5	282.0	3.823E+07	0.126	0.076	0.07	4.99	5.03
	08:38	6.6	282.8	3.833E+07	0.119	0.076	0.08	4.99	5.04
	08:39	6.8	283.0	3.830E+07	0.112	0.075	0.08	5.06	5.10
	08:40	6.7	283.3	3.829E+07	0.126	0.077	0.08	5.04	5.07
	08:41	6.3	283.0	3.827E+07	0.114	0.074	0.08	4.93	4.98
	08:42	6.3	282.7	3.826E+07	0.106	0.075	0.08	4.78	4.82
	08:43	6.8	282.5	3.824E+07	0.115	0.075	0.08	5.04	5.09
	08:44	6.9	281.9	3.826E+07	0.123	0.075	0.08	5.11	5.17
	08:45	6.5	281.7	3.830E+07	0.123	0.074	0.08	5.02	5.07
	08:46	6.4	281.0	3.829E+07	0.122	0.074	0.08	5.00	5.02
	08:47	6.1	280.8	3.829E+07	0.113	0.074	0.08	4.77	4.76
	08:48	6.4	281.1	3.833E+07	0.121	0.076	0.07	4.93	4.92
	08:49	6.7	281.4	3.816E+07	0.137	0.076	0.07	5.03	5.02
	08:50	6.7	281.4	3.813E+07	0.135	0.076	0.07	4.97	4.99

Plant Name: EKSP

General Average Report

Reporting Period: 08/18/2005 to 08/18/2005

Site Name: UNIT03

Time of Report: 08/18/05 13:00

Data Averaging Type: 1m

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/18/05	08:51	7.0	282.4	3.837E+07	0.122	0.077	0.07	5.25	5.29
	08:52	6.4	282.7	3.854E+07	0.122	0.077	0.08	4.88	4.88
	08:53	6.8	282.7	3.847E+07	0.108	0.077	0.08	5.03	5.04
	08:54	6.9	282.7	3.824E+07	0.108	0.075	0.08	5.15	5.16
	08:55	6.8	282.7	3.828E+07	0.099	0.075	0.08	5.02	4.99
	08:56	7.2	282.7	3.840E+07	0.096	0.074	0.08	5.25	5.26
	08:57	6.5	282.7	3.840E+07	0.107	0.074	0.08	4.91	4.90
	08:58	7.1	282.7	3.834E+07	0.123	0.078	0.08	5.14	5.16
	08:59	7.0	282.7	3.843E+07	0.142	0.077	0.08	5.02	5.00
	09:00	7.1	282.7	3.849E+07	0.123	0.076	0.08	5.10	5.07
	09:01	7.5	282.6	3.850E+07	0.109	0.074	0.08	5.19	5.17
	09:02	6.7	283.0	3.866E+07	0.123	0.075	0.07	4.94	4.95
	09:03	7.0	283.0	3.860E+07	0.132	0.075	0.07	5.01	5.11
	09:04	7.1	283.0	3.837E+07	0.138	0.075	0.07	4.98	5.17
	09:05	6.5	282.8	3.832E+07	0.144	0.076	0.07	4.81	4.93
	09:06	6.9	283.1	3.829E+07	0.140	0.077	0.07	4.95	5.09
	09:07	6.6	283.4	3.829E+07	0.155	0.075	0.07	4.84	4.95
	09:08	7.1	284.1	3.837E+07	0.154	0.075	0.07	5.02	5.12
	09:09	7.1	284.9	3.839E+07	0.141	0.075	0.08	5.02	5.12
Average =		6.6	282.9	3.826E+07	0.129	0.075	0.08	5.01	5.04
Maximum =		7.5	284.9	3.866E+07	0.169	0.078	0.08	5.25	5.29
Minimum =		5.8	280.8	3.799E+07	0.096	0.071	0.07	4.65	4.69
Possible Values =		69	69	69	69	69	69	69	69
luded Values =		69	69	69	69	69	69	69	69
Total =		455.3	19516.7	2.640E+09	8.876	5.196	5.23	345.62	347.59

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

run 2
60%

Plant Name: EKSP

General Average Report

Reporting Period: 08/18/2005 to 08/18/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:01

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/18/05	09:41	6.7	283.0	3.848E+07	0.127	0.075	0.08	5.14	5.19
	09:42	6.3	283.1	3.847E+07	0.136	0.075	0.07	4.99	5.06
	09:43	6.4	283.8	3.838E+07	0.125	0.078	0.07	5.05	5.20
	09:44	6.1	283.5	3.844E+07	0.126	0.077	0.08	4.87	5.00
	09:45	6.2	282.6	3.848E+07	0.130	0.075	0.08	4.98	5.10
	09:46	6.3	282.2	3.847E+07	0.130	0.076	0.08	5.03	5.17
	09:47	6.1	282.3	3.848E+07	0.128	0.076	0.07	4.96	5.04
	09:48	6.6	282.3	3.845E+07	0.138	0.077	0.07	5.18	5.26
	09:49	6.2	281.9	3.860E+07	0.132	0.076	0.08	4.95	4.96
	09:50	6.5	282.2	3.866E+07	0.122	0.076	0.08	5.13	5.17
	09:51	6.2	282.6	3.853E+07	0.114	0.074	0.08	5.02	5.02
	09:52	6.3	282.5	3.854E+07	0.121	0.077	0.08	5.06	5.06
	09:53	6.2	281.7	3.850E+07	0.118	0.077	0.08	4.99	4.92
	09:54	6.5	281.1	3.852E+07	0.132	0.076	0.08	5.22	5.19
	09:55	6.2	281.0	3.868E+07	0.119	0.075	0.08	5.08	5.07
	09:56	6.1	280.6	3.874E+07	0.110	0.075	0.08	5.00	5.02
	09:57	6.1	280.1	3.867E+07	0.104	0.076	0.08	4.83	4.92
	09:58	6.1	280.2	3.858E+07	0.104	0.074	0.07	5.04	5.16
	09:59	6.2	280.3	3.849E+07	0.112	0.075	0.07	4.97	5.04
	10:00	6.2	281.7	3.846E+07	0.111	0.073	0.07	5.01	5.06
	10:01	6.5	282.1	3.858E+07	0.100	0.075	0.08	5.13	5.24
	10:02	6.0	281.7	3.861E+07	0.104	0.074	0.08	4.90	4.86
	10:03	5.8	282.1	3.844E+07	0.096	0.073	0.07	4.71	4.82
	10:04	6.3	282.2	3.828E+07	0.102	0.074	0.08	5.02	5.14
	10:05	6.1	281.9	3.835E+07	0.114	0.073	0.08	4.97	5.09
	10:06	6.4	281.9	3.853E+07	0.101	0.072	0.08	5.11	5.22
	10:07	6.4	281.7	3.844E+07	0.096	0.074	0.08	4.95	5.01
	10:08	6.3	281.9	3.827E+07	0.108	0.073	0.08	5.04	5.07
	10:09	6.4	281.8	3.840E+07	0.124	0.076	0.07	5.03	5.13
	10:10	6.3	281.6	3.850E+07	0.132	0.075	0.08	5.05	5.13
	10:11	6.2	281.9	3.850E+07	0.120	0.075	0.07	4.94	5.01
	10:12	6.4	281.9	3.847E+07	0.118	0.075	0.08	5.08	5.15
	10:13	6.2	281.8	3.841E+07	0.108	0.075	0.07	5.03	5.12
	10:14	6.4	281.4	3.841E+07	0.100	0.075	0.08	5.06	5.15
	10:15	6.3	281.4	3.846E+07	0.090	0.074	0.08	5.03	5.06
	10:16	6.1	281.2	3.847E+07	0.100	0.074	0.08	4.86	4.87
	10:17	6.3	280.3	3.851E+07	0.111	0.076	0.08	5.06	5.05
	10:18	6.0	279.8	3.849E+07	0.119	0.075	0.08	4.85	4.85
	10:19	6.2	279.6	3.839E+07	0.108	0.072	0.08	4.96	4.95
	10:20	6.3	280.0	3.841E+07	0.114	0.074	0.08	4.96	4.95
	10:21	6.4	280.3	3.840E+07	0.144	0.077	0.07	5.02	5.05
	10:22	6.1	281.6	3.834E+07	0.137	0.075	0.07	4.91	4.91
	10:23	6.3	281.8	3.823E+07	0.121	0.073	0.07	5.02	5.03
	10:24	5.9	281.4	3.815E+07	0.128	0.074	0.07	4.84	4.83
	10:25	6.3	281.4	3.815E+07	0.107	0.073	0.07	5.04	5.03
	10:26	6.4	281.4	3.819E+07	0.125	0.075	0.07	5.09	5.06
	10:27	6.3	281.1	3.821E+07	0.118	0.071	0.07	5.05	4.97
	10:28	6.4	281.0	3.825E+07	0.113	0.071	0.07	5.03	4.99
	10:29	6.4	280.6	3.818E+07	0.115	0.072	0.07	5.08	5.10
	10:30	6.6	280.0	3.812E+07	0.124	0.073	0.07	5.13	5.18

Plant Name: EKSP

General Average Report

Reporting Period: 08/18/2005 to 08/18/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:01

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/18/05	10:31	6.4	279.9	3.813E+07	0.142	0.072	0.07	5.02	4.99
	10:32	6.4	280.0	3.822E+07	0.132	0.073	0.07	5.06	5.03
	10:33	6.6	280.3	3.824E+07	0.146	0.073	0.07	5.10	5.13
	10:34	6.3	280.4	3.809E+07	0.151	0.073	0.07	5.02	5.00
	10:35	6.2	280.5	3.806E+07	0.152	0.072	0.07	4.90	4.91
	10:36	6.4	281.1	3.810E+07	0.124	0.070	0.07	5.08	5.15
	10:37	6.4	281.1	3.808E+07	0.119	0.072	0.07	4.96	5.02
	10:38	6.0	281.1	3.810E+07	0.112	0.070	0.07	4.88	4.92
	10:39	5.7	281.5	3.812E+07	0.126	0.071	0.07	4.63	4.64
	10:40	6.0	282.6	3.807E+07	0.128	0.075	0.07	4.75	4.80
	10:41	6.4	282.8	3.803E+07	0.129	0.074	0.07	5.09	5.14
	10:42	6.2	282.4	3.800E+07	0.129	0.074	0.07	4.95	4.96
	10:43	6.3	282.3	3.807E+07	0.109	0.071	0.07	5.03	5.07
	10:44	6.2	281.9	3.807E+07	0.104	0.070	0.07	5.06	5.07
	10:45	6.1	281.9	3.808E+07	0.110	0.072	0.07	4.96	5.01
	10:46	6.7	281.6	3.810E+07	0.116	0.072	0.07	5.17	5.21
	10:47	6.1	280.6	3.807E+07	0.128	0.072	0.07	5.01	4.97
	10:48	5.9	279.9	3.816E+07	0.114	0.072	0.07	4.81	4.79
	10:49	6.3	279.7	3.819E+07	0.120	0.075	0.07	4.99	5.01
Average =		6.3	281.4	3.834E+07	0.119	0.074	0.07	5.00	5.04
Maximum =		6.7	283.8	3.874E+07	0.152	0.078	0.08	5.22	5.26
Minimum =		5.7	279.6	3.800E+07	0.090	0.070	0.07	4.63	4.64
Possible Values =		69	69	69	69	69	69	69	69
cluded Values =		69	69	69	69	69	69	69	69
Total =		432.2	19419.5	2.646E+09	8.227	5.102	5.15	344.91	347.48

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

run 5
6%

Plant Name: EKSP

General Average Report

Reporting Period: 08/18/2005 to 08/18/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:02

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/18/05	11:11	6.4	281.6	3.833E+07	0.129	0.071	0.08	5.13	5.15
	11:12	6.1	281.8	3.827E+07	0.131	0.069	0.08	5.02	5.04
	11:13	6.4	281.6	3.827E+07	0.133	0.073	0.08	5.12	5.16
	11:14	6.2	281.8	3.833E+07	0.134	0.073	0.08	4.99	5.03
	11:15	6.3	281.4	3.833E+07	0.121	0.072	0.08	4.94	4.99
	11:16	6.3	281.0	3.829E+07	0.111	0.071	0.08	4.95	5.02
	11:17	6.5	280.4	3.836E+07	0.113	0.070	0.07	5.07	5.18
	11:18	6.0	280.4	3.830E+07	0.105	0.070	0.07	4.89	4.94
	11:19	6.1	280.6	3.819E+07	0.102	0.071	0.07	4.95	5.01
	11:20	6.3	281.5	3.821E+07	0.116	0.070	0.07	5.04	5.09
	11:21	6.3	281.6	3.820E+07	0.120	0.072	0.08	5.05	5.09
	11:22	6.4	281.9	3.822E+07	0.100	0.070	0.08	5.02	5.06
	11:23	6.8	281.9	3.818E+07	0.116	0.070	0.07	5.21	5.27
	11:24	6.1	281.9	3.821E+07	0.127	0.072	0.08	4.92	4.94
	11:25	6.0	282.0	3.823E+07	0.125	0.070	0.08	4.88	4.94
	11:26	6.1	282.2	3.811E+07	0.115	0.069	0.08	4.96	5.01
	11:27	6.1	281.8	3.814E+07	0.119	0.069	0.08	4.90	4.99
	11:28	6.2	281.7	3.829E+07	0.119	0.069	0.08	5.00	5.09
	11:29	6.6	282.3	3.835E+07	0.110	0.069	0.08	5.14	5.22
	11:30	6.1	282.3	3.839E+07	0.125	0.072	0.08	4.90	4.92
	11:31	6.6	282.1	3.835E+07	0.117	0.069	0.08	5.14	5.22
	11:32	6.1	282.0	3.839E+07	0.122	0.074	0.08	5.00	5.06
	11:33	6.2	282.1	3.845E+07	0.118	0.071	0.08	5.05	5.11
	11:34	6.5	282.0	3.839E+07	0.123	0.071	0.08	5.14	5.20
	11:35	6.0	282.3	3.836E+07	0.119	0.071	0.07	4.97	4.96
	11:36	6.1	282.4	3.835E+07	0.120	0.078	0.07	5.02	5.04
	11:37	5.7	283.0	3.829E+07	0.141	0.078	0.07	4.69	4.74
	11:38	5.9	283.0	3.830E+07	0.129	0.070	0.07	4.85	4.95
	11:39	6.3	283.0	3.842E+07	0.131	0.070	0.08	5.06	5.16
	11:40	5.9	282.6	3.832E+07	0.119	0.071	0.08	4.77	4.82
	11:41	5.5	282.3	3.834E+07	0.108	0.072	0.07	4.60	4.69
	11:42	5.6	282.4	3.845E+07	0.112	0.074	0.08	4.70	4.78
	11:43	6.2	282.6	3.844E+07	0.116	0.071	0.08	5.02	5.09
	11:44	6.5	282.4	3.843E+07	0.123	0.070	0.08	5.03	5.07
	11:45	6.3	282.8	3.832E+07	0.120	0.068	0.08	5.02	5.04
	11:46	6.3	283.1	3.825E+07	0.107	0.069	0.08	5.10	5.12
	11:47	6.5	283.0	3.824E+07	0.135	0.071	0.08	5.08	5.09
	11:48	6.3	282.8	3.825E+07	0.137	0.070	0.08	4.98	5.07
	11:49	6.5	283.0	3.835E+07	0.121	0.070	0.07	5.09	5.19
	11:50	6.2	282.8	3.837E+07	0.131	0.077	0.08	4.96	5.18
	11:51	5.8	281.9	3.825E+07	0.162	0.081	0.08	4.71	4.85
	11:52	6.0	281.8	3.816E+07	0.150	0.071	0.08	4.92	5.06
	11:53	6.3	281.5	3.820E+07	0.141	0.071	0.08	5.00	5.16
	11:54	6.4	281.5	3.821E+07	0.121	0.069	0.07	4.96	5.05
	11:55	6.3	281.6	3.827E+07	0.117	0.071	0.07	5.07	5.15
	11:56	6.6	282.3	3.832E+07	0.116	0.070	0.08	5.13	5.22
	11:57	6.0	283.4	3.836E+07	0.117	0.069	0.08	4.90	4.93
	11:58	6.3	283.3	3.841E+07	0.123	0.071	0.08	5.03	5.06
	11:59	6.3	283.0	3.849E+07	0.120	0.068	0.08	5.03	5.07
	12:00	6.4	283.1	3.853E+07	0.107	0.069	0.08	5.13	5.21

Plant Name: EKSP

General Average Report

Reporting Period: 08/18/2005 to 08/18/2005

Site Name: UNIT03

Data Averaging Type: 1m

Time of Report: 08/18/05 13:02

Rolling Average Interval: 1

Date	Time	OPACITY (PERCENT)	LOADMW (MW)	FLOWSCFH (SCFH)	SO2#/MM (LB/MMBTU)	CO#/MM (LB/MMBTU)	NOX#MM60 (LB/MMBTU)	BAGPRESA (inW)	BAGPRESB (inW)
08/18/05	12:01	6.0	283.3	3.852E+07	0.119	0.069	0.08	4.92	5.02
	12:02	6.4	282.5	3.837E+07	0.131	0.071	0.08	5.16	5.27
	12:03	5.8	281.9	3.824E+07	0.127	0.069	0.08	4.86	4.96
	12:04	6.2	281.8	3.826E+07	0.128	0.070	0.08	5.07	5.19
	12:05	5.8	281.5	3.825E+07	0.144	0.073	0.08	4.79	4.89
	12:06	6.0	281.8	3.828E+07	0.128	0.070	0.08	4.91	5.01
	12:07	5.9	281.4	3.828E+07	0.131	0.070	0.08	4.81	4.94
	12:08	5.9	281.5	3.821E+07	0.140	0.071	0.08	4.87	4.99
	12:09	6.4	281.5	3.825E+07	0.128	0.070	0.08	5.09	5.25
	12:10	5.8	281.6	3.835E+07	0.132	0.071	0.08	4.82	4.94
	12:11	5.6	282.0	3.838E+07	0.127	0.072	0.08	4.72	4.87
	12:12	6.0	282.2	3.836E+07	0.137	0.071	0.08	4.91	5.05
	12:13	6.4	282.2	3.830E+07	0.147	0.072	0.08	5.06	5.22
	12:14	5.9	282.0	3.830E+07	0.140	0.071	0.08	4.87	4.99
	12:15	6.2	282.3	3.832E+07	0.140	0.079	0.08	4.99	5.11
	12:16	6.2	282.2	3.834E+07	0.137	0.074	0.08	5.01	5.04
	12:17	6.4	282.3	3.830E+07	0.120	0.070	0.08	5.06	5.08
	12:18	6.2	282.3	3.832E+07	0.116	0.070	0.08	5.02	5.04
	12:19	6.0	282.4	3.838E+07	0.118	0.073	0.08	4.94	5.03
	12:20	6.2	282.6	3.832E+07	0.119	0.071	0.08	5.02	5.14
	12:21	6.0	282.1	3.830E+07	0.110	0.071	0.08	4.97	5.06
	12:22	5.9	281.4	3.837E+07	0.114	0.071	0.08	4.80	4.88
Average =		6.2	282.1	3.831E+07	0.124	0.071	0.08	4.97	5.05
Maximum =		6.8	283.4	3.853E+07	0.162	0.081	0.08	5.21	5.27
Minimum =		5.5	280.4	3.811E+07	0.100	0.068	0.07	4.60	4.69
Possible Values =		72	72	72	72	72	72	72	72
Included Values =		72	72	72	72	72	72	72	72
Total =		444.6	20311.3	2.758E+09	8.928	5.122	5.52	357.90	363.44

* - excluded values (missing, OOC, invalid, suspect)
< - missing
T - out-of-control
I - invalid
S - suspect
H - exceedance
F - stack not operating
B - invalid (PADER)
U - missing data substituted
-999 - missing value
-888 - value could not be calculated

APPENDIX 3

REFERENCE METHOD TEST RESULTS - PARTICULATE

Fly Ash Silo Baghouse

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Flyash Silo Baghouse

Run No: **1** Date: 6/16/05 Start Time: 7:45
End Time: 8:57

DIAMETER OF NOZZLE:	0.280		STACK DIMENSIONS:	32.5 x 15	inches
AREA OF NOZZLE:	4.276E-04	A_n	AREA OF STACK:	3.4	sq. ft.
BAROMETRIC PRESSURE:	29.88	P_{bar}	VOLUME OF MOISTURE:	34	V_{lc}
GAS METER Y-FACTOR:	0.98	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		169.286										
A-1	2.5	170.9	0.16	0.90	68	68	88				9.36	23.1
2	2.5	172.0	0.15	0.85	69	69	93	0.0	20.9	0.11	9.11	22.5
3	2.5	173.5	0.16	0.90	68	68	94				9.41	23.2
4	2.5	174.9	0.16	0.90	69	69	94				9.41	23.2
5	2.5	176.099	0.18	1.00	69	69	87				9.92	24.5
		176.099										
B-1	2.5	177.5	0.18	1.00	69	69	91				9.96	24.6
2	2.5	179.0	0.18	1.00	69	69	95				9.99	24.7
3	2.5	180.5	0.20	1.10	69	69	96				10.55	26.0
4	2.5	181.6	0.15	0.85	69	69	94				9.12	22.5
5	2.5	183.277	0.19	1.05	70	70	91				10.23	25.2
		183.277										
C-1	2.5	184.8	0.20	1.10	70	70	95				10.54	26.0
2	2.5	186.2	0.17	0.96	70	70	97				9.73	24.0
3	2.5	187.6	0.17	0.96	70	70	98				9.74	24.0
4	2.5	189.2	0.19	1.05	71	71	96				10.28	25.4
5	2.5	190.548	0.18	1.00	71	71	91				9.96	24.6
		190.548										
D-1	2.5	191.9	0.16	0.90	71	71	93				9.41	23.2
2	2.5	193.4	0.19	1.05	72	72	99				10.31	25.4
3	2.5	194.8	0.15	0.85	72	72	100				9.17	22.6
4	2.5	196.1	0.17	0.96	72	72	101				9.77	24.1
5	2.5	197.593	0.16	0.90	73	73	99				9.46	23.3
		197.593										
E-1	2.5	199.0	0.18	1.00	73	73	99				10.03	24.7
2	2.5	200.4	0.18	1.00	73	73	104				10.08	24.9
3	2.5	201.9	0.18	1.00	74	74	103				10.07	24.8
4	2.5	203.2	0.15	0.85	74	74	101				9.17	22.6
5	2.5	204.547	0.15	0.73	74	74	92				9.10	22.4
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	62.5	35.261	0.414	0.954		71	96	0.0	20.9	0.11	9.75	24.1
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.89	$V_{m(std)}$ =	34.397	$V_{w(std)}$ =	1.601	%M=	4.45
B_{ws} =	0.044	M_d =	28.84	M_s =	28.35		

STACK GAS VELOCITY =	24.1	AFPS	V_s
STACK GAS VELOCITY =	1,444	AFPM	
STACK GAS VOLUME =	4,452	DSCFM	Q_{std}
STACK GAS VOLUME =	4,909	ACFM	Q_a
ISOKINETIC RATIO =	98.3	%	

EMISSIONS

Weight, mg =	2.9
GR/DSCF =	0.001
GR/DSCM =	0.046
LBS/HR =	0.05

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Flyash Silo Baghouse

Run No: **2** Date: 6/16/05 Start Time: 9:15
End Time: 10:17

DIAMETER OF NOZZLE:	0.280		STACK DIMENSIONS:	32.5 x 15	inches
AREA OF NOZZLE:	4.276E-04	A_n	AREA OF STACK:	3.4	sq. ft.
BAROMETRIC PRESSURE:	29.88	P_{bar}	VOLUME OF MOISTURE:	32	V_{lc}
GAS METER Y-FACTOR:	0.98	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		204.802										
E-1	2.5	204.1	0.18	1.00	74	74	96				10.00	24.7
2	2.5	207.3	0.18	1.00	74	74	102	0.0	20.9	0.11	10.06	24.8
3	2.5	209.0	0.18	1.00	74	74	102				10.06	24.8
4	2.5	210.7	0.18	1.00	74	74	103				10.07	24.8
5	2.5	211.993	0.15	0.85	74	74	99				9.16	22.6
		211.993										
D-1	2.5	213.4	0.16	0.90	74	74	100				9.47	23.3
2	2.5	214.9	0.20	1.10	74	74	102				10.60	26.1
3	2.5	216.4	0.18	1.00	75	75	101				10.05	24.8
4	2.5	217.9	0.18	1.00	75	75	98				10.02	24.7
5	2.5	219.188	0.16	0.90	75	75	96				9.43	23.3
		219.188										
C-1	2.5	220.6	0.21	1.20	75	75	97				10.82	26.7
2	2.5	222.3	0.21	1.20	75	75	101				10.85	26.8
3	2.5	223.8	0.17	0.96	75	75	102				9.77	24.1
4	2.5	225.2	0.15	0.85	75	75	101				9.17	22.6
5	2.5	226.523	0.15	0.85	76	76	94				9.12	22.5
		226.523										
B-1	2.5	228.3	0.25	1.40	76	76	98				11.81	29.1
2	2.5	229.6	0.18	1.00	76	76	104				10.08	24.8
3	2.5	231.3	0.20	1.10	76	76	105				10.63	26.2
4	2.5	232.7	0.17	0.96	76	76	105				9.80	24.2
5	2.5	234.174	0.17	0.96	76	76	99				9.75	24.0
		234.174										
A-1	2.5	235.5	0.15	0.85	77	77	103				9.19	22.7
2	2.5	236.7	0.15	0.85	77	77	108				9.23	22.8
3	2.5	238.3	0.18	1.00	77	77	109				10.12	24.9
4	2.5	239.7	0.16	0.90	77	77	108				9.53	23.5
5	2.5	241.082	0.15	0.85	78	78	102				9.18	22.6
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	62.5	36.280	0.419	0.987		75	101	0.0	20.9	0.11	9.92	24.5
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.89	$V_{m(std)}$ =	35.087	$V_{w(std)}$ =	1.507	%M=	4.12
B_{ws} =	0.041	M_d =	28.84	M_s =	28.39		

STACK GAS VELOCITY =	24.5	AFPS	V_s	EMISSIONS	
STACK GAS VELOCITY =	1,467	AFPM		Weight, mg =	1.9
STACK GAS VOLUME =	4,493	DSCFM	Q_{std}	GR/DSCF =	0.001
STACK GAS VOLUME =	4,988	ACFM	Q_a	GR/DSCM =	0.029
ISOKINETIC RATIO =	99.4	%		LBS/HR =	0.03

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Flyash Silo Baghouse

Run No: **3** Date: 6/16/05 Start Time: 10:40
End Time: 11:53

DIAMETER OF NOZZLE:	0.280		STACK DIMENSIONS:	32.5 x 15	inches
AREA OF NOZZLE:	4.276E-04	A_n	AREA OF STACK:	3.4	sq. ft.
BAROMETRIC PRESSURE:	29.88	P_{bar}	VOLUME OF MOISTURE:	35	V_{lc}
GAS METER Y-FACTOR:	0.98	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		241.734										
A-1	2.5	243.1	0.16	0.90	78	78	99				9.46	23.3
2	2.5	244.5	0.17	0.96	78	78	106	0.0	20.9		9.81	24.2
3	2.5	246.1	0.19	1.05	78	78	106			0.12	10.37	25.6
4	2.5	247.4	0.15	0.85	78	78	103				9.19	22.7
5	2.5	248.832	0.15	0.85	78	78	96				9.13	22.5
		248.832										
B-1	2.5	250.3	0.21	1.20	79	79	100				10.84	26.8
2	2.5	252.1	0.22	1.25	79	79	104				11.14	27.5
3	2.5	253.5	0.19	1.05	79	79	104				10.35	25.5
4	2.5	255.1	0.17	0.96	79	79	104				9.79	24.2
5	2.5	256.479	0.16	0.90	80	80	92				9.40	23.2
		256.479										
C-1	2.5	257.9	0.17	0.96	80	80	99				9.75	24.1
2	2.5	259.3	0.18	1.00	80	80	103				10.07	24.8
3	2.5	260.8	0.18	1.00	80	80	103				10.07	24.8
4	2.5	262.1	0.15	0.85	80	80	101				9.17	22.6
5	2.5	263.732	0.18	1.00	80	80	97				10.01	24.7
		263.732										
D-1	2.5	265.2	0.20	1.10	80	80	97				10.55	26.0
2	2.5	266.8	0.20	1.10	80	80	101				10.59	26.1
3	2.5	268.3	0.18	1.00	80	80	102				10.06	24.8
4	2.5	269.8	0.18	1.00	80	80	102				10.06	24.8
5	2.5	271.227	0.15	0.85	80	80	98				9.15	22.6
		271.227										
D-1	2.5	272.5	0.17	0.96	80	80	98				9.74	24.0
2	2.5	274.1	0.16	0.90	80	80	101				9.47	23.4
3	2.5	275.8	0.16	0.90	80	80	101				9.47	23.4
4	2.5	276.9	0.16	0.90	80	80	101				9.47	23.4
5	2.5	277.931	0.16	0.90	80	80	95				9.42	23.2
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	62.5	36.197	0.417	0.976		79	101	0.0	20.9	0.12	9.86	24.3
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.89	$V_{m(std)}$ =	34.744	$V_{w(std)}$ =	1.649	%M=	4.53
B_{ws} =	0.045	M_d =	28.84	M_s =	28.35		

STACK GAS VELOCITY =	24.3	AFPS	V_s
STACK GAS VELOCITY =	1,460	AFPM	
STACK GAS VOLUME =	4,459	DSCFM	Q_{std}
STACK GAS VOLUME =	4,964	ACFM	Q_a
ISOKINETIC RATIO =	99.2	%	

EMISSIONS

Weight, mg =	1.3
GR/DSCF =	0.001
GR/DSCM =	0.020
LBS/HR =	0.02

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 21	Filter Number	573
Plant	Spurlock 3	Nozzle No.	43	Initial Leak (Samp.)	0.000 @ 11"
Location	Fly Ash Baghouse	Nozzle Dn.	0.280	Initial Leak (Pitot)	ok @ 3.5
Test	PM - M17	TC No.	CAM21		ok @ 3.5
Run	1	P_B	29.88		
Date	6-16-05	Ambient Temp	75	Final Leak (Samp.)	0.000 @ 5"
Meter Box	070	Static	0.11	Final Leak (Pitot)	ok @ 3.0
ΔH	1.64 | Y_1 0.98				ok @ 3.0

K = 5.62

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	0745		169.786				NA	NA				
A 1		2.5	170.9	.16	0.90	88			68	68	66	0.5
2		5.0	172.0	0.15	0.85	93			69	69	64	0.5
3		7.5	173.5	0.16	0.90	94			68	68	62	0.5
4		10.0	174.9	0.16	0.90	94			69	69	61	0.5
5	0758	12.5	176.099	0.18	1.00	87			69	69	61	0.5
B 1	0800	2.5	177.5	0.18	1.00	91			69	69	63	0.5
2		5.0	179.0	0.18	1.00	95			69	69	60	0.5
3		7.5	180.5	0.20	1.10	96			69	69	61	1.0
4		10.0	181.6	0.15	0.85	94			69	69	61	0.5
5	0812	12.5	183.277	0.19	1.05	91			70	70	61	1.0
C 1	0814	2.5	184.8	0.20	1.10	95			70	70	63	1.0
2		5.0	186.2	0.17	0.96	97			70	70	61	1.0
3		7.5	187.6	0.17	0.96	98			70	70	62	1.0
4		10.0	189.2	0.19	1.05	96			71	71	62	1.0
5	0827	12.5	190.548	0.18	1.00	91			71	71	62	1.0
D 1	0830	2.5	191.9	0.16	0.90	93			71	71	66	0.5
2		5.0	193.4	0.19	1.05	99			72	72	63	1.0
3		7.5	194.8	0.15	0.85	100			72	72	61	0.5
4		10.0	196.1	0.17	0.96	101			72	72	60	1.0
5	0842	12.5	197.593	0.16	0.90	99			73	73	59	0.5
E 1	0844	2.5	199.0	0.18	1.00	99			73	73	60	1.0
2		5.0	200.4	0.18	1.00	104			73	73	59	1.0
3		7.5	201.9	0.19	1.00	103			74	74	59	1.0
4		10.0	203.2	0.15	0.85	101			74	74	59	0.5
5	0857	12.5	204.547	0.13	0.73	92			74	74	60	0.5

COMMENTS:

Ambient
20.9
0

100 120
100 106
0 0
0 260
252

Baghouse
ΔP 1.5
2.5
2.0

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/16/05
SAMPLING TIME: (24 HR CLOCK) 0745 - 0857
SAMPLING LOCATION: Flyash silo
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) _____
TECHNICIAN: Taylor

Run 1
FLY ASH

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							20.9	**Fuel Type**	**Fo (calc)**
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER ok

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	120	106	0				258	
INITIAL (ml)	100	100	0				250	
NET (ml)	20	6	0				8	34
TOTALS								34

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	573			WEIGHED BY
FINAL WEIGHT	0.1125			MT
INITIAL WEIGHT	0.1105			CA
DIFFERENCE	0.0020			MT
PARTICULATE CATCH	2.0			MT

PROBE/NOZZLE WASH

BEAKER NO.	23		Blank	WEIGHED BY
FINAL WEIGHT	104.7869		110.4567	MT
INITIAL WEIGHT	104.7858		110.4565	
DIFFERENCE	0.0011		0.0002	
PARTICULATE CATCH	1.1		0.2	

TOTAL PARTICULATE CATCH (mg) 3.9

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM21	Filter Number	574
Plant	Spurlock 3	Nozzle No.	105	Initial Leak (Samp.)	0.002 @ 11"
Location	Fly Ash Baghouse	Nozzle Dn.	0.280	Initial Leak (Pitot)	✓ @ 3.0
Test	PM - MM	TC No.	CAM21		✓ @ 3.0
Run	R2	P_B	29.88		
Date	6-16-05	Ambient Temp	75	Final Leak (Samp.)	0.000 @ 2.5"
Meter Box	070	Static	0.11	Final Leak (Pitot)	✓ @ 2.1
ΔH	1.64 | Y_1 0.98				✓ @ 2.2

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	0915		204.802									
E1		2.5	204.1	0.18	1.00	96			74	74	67	0.5
2		5.0	207.3	0.18	1.00	102			74	74	61	0.5
3		7.5	209.0	0.18	1.00	102			74	74	59	1.0
4		10.0	210.7	0.18	1.00	103			74	74	58	1.0
5	0918	12.5	211.993	0.15	0.85	99			74	74	58	0.5
D1	0920	2.5	213.4	0.16	0.90	100			74	74	61	0.5
2		5.0	214.9	0.20	1.10	102			74	74	60	1.0
3		7.5	216.4	0.18	1.00	101			75	75	58	1.0
4		10.0	217.9	0.18	1.00	98			75	75	59	1.0
5	0933	12.5	219.188	0.16	0.90	96			75	75	58	0.5
C1	0935	2.5	220.6	0.21	1.20	97			75	75	61	1.0
2		5.0	222.3	0.21	1.20	101			75	75	58	1.0
3		7.5	223.8	0.17	0.96	102			75	75	58	1.0
4		10.0	225.2	0.15	0.85	101			75	75	60	0.5
5	0948	12.5	226.523	0.15	0.85	94			76	76	61	0.5
B1	0950	2.5	228.3	0.25	1.40	98			76	76	64	1.0
2		5.0	229.6	0.18	1.00	104			76	76	61	1.0
3		7.5	231.3	0.20	1.10	105			76	76	59	1.0
4		10.0	232.7	0.17	0.96	105			76	76	59	1.0
5	1002	12.5	234.174	0.17	0.96	99			76	76	60	1.0
A1	1005	2.5	235.5	0.15	0.85	103			77	77	63	0.5
2		5.0	236.7	0.15	0.85	108			77	77	60	0.5
3		7.5	238.3	0.18	1.00	109			77	77	59	1.0
4		10.0	239.7	0.16	0.90	108			77	77	58	1.0
5	1017	12.5	241.082	0.15	0.85	102			78	78	59	0.5

COMMENTS:

Ambient 100 118
20.9 100 104
Ø Ø 4
264 270

Baghouse 2.5
ΔP 2.0
2.0

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/16/05
SAMPLING TIME: (24 HR CLOCK) 0915 - 1017
SAMPLING LOCATION: Flyash Silo
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 75
TECHNICIAN: Taylor

Run 2
Flyash

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = 20.9 − %O2 / %CO2	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2			Ambient				0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							20.9	Fuel Type	Fo (calc)
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	118	104	4				256	
INITIAL (ml)	100	100	0				250	
NET (ml)	18	4	4				6	32
TOTALS								32

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	574			WEIGHED BY	BEAKER NO.	10		Blank	WEIGHED BY
FINAL WEIGHT	0.1108			MT	FINAL WEIGHT	96.4153			MT
INITIAL WEIGHT	0.1105			CA	INITIAL WEIGHT	96.4135			
DIFFERENCE	0.0003			MT	DIFFERENCE	0.0018			
PARTICULATE CATCH	0.3			MT	PARTICULATE CATCH	1.3		0.2	

TOTAL PARTICULATE CATCH (mg) 1.9

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	ELPC	Pitot No.	CAM 21	Filter Number	571
Plant	Spurlock 3	Nozzle No.	51	Initial Leak (Samp.)	0.003 @ 11"
Location	Fly Ash Baghouse	Nozzle Dn.	0.280	Initial Leak (Pitot)	~~0~~ @ 2.1
Test	PM - M17	TC No.	CAM21		~~0~~ @ 2.4
Run	3	P_B	29.88		
Date	6-16-05	Ambient Temp	80	Final Leak (Samp.)	0.000 @ 2.0"
Meter Box	070	Static	0.12	Final Leak (Pitot)	~~0~~ @ 3.0
ΔH	1.64 | Y_1 0.98				~~0~~ @ 3.0

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1040		241.734				NA	NA				
A1		2.5	243.1	0.16	0.90	99			78	78	66	0.5
2		5.0	244.5	0.17	0.96	106			78	78	64	0.5
3		7.5	246.1	0.19	1.05	106			78	78	63	0.5
4		10.0	247.4	0.15	0.85	103			78	78	62	0.5
5	1053	12.5	248.832	0.15	0.85	96			78	78	61	0.5
B1	1055	2.5	250.3	0.21	1.20	100			79	79	62	1.0
2		5.0	252.1	0.22	1.25	104			79	79	60	1.0
3		7.5	253.5	0.19	1.05	104			79	79	59	1.0
4		10.0	255.1	0.17	0.96	104			79	79	60	1.0
5	1108	12.5	256.479	0.16	0.90	92			80	80	61	1.0
C1	1110	2.5	257.9	0.17	0.96	99			80	80	64	1.0
2		5.0	259.3	0.18	1.00	103			80	80	64	1.0
3		7.5	260.8	0.18	1.00	103			80	80	64	1.0
4		10.0	262.1	0.15	0.85	101			80	80	63	0.5
5	1123	12.5	263.732	0.18	1.00	97			80	80	62	1.0
D1	1125	2.5	265.2	0.20	1.10	97			80	80	62	1.5
2		5.0	266.8	0.20	1.10	101			80	80	61	1.5
3		7.5	268.3	0.18	1.00	102			80	80	61	1.0
4		10.0	269.8	0.18	1.00	102			80	80	61	1.0
5	1138	12.5	271.227	0.15	0.85	98			80	80	61	0.5
E1	1140	2.5	272.5	0.17	0.96	98			80	80	65	1.0
2		5.0	274.1	0.16	0.90	101			80	80	64	1.0
3		7.5	275.8	0.16	0.90	101			80	80	63	1.0
4		10.0	276.9	0.16	0.90	101			80	80	62	1.0
5	1158	12.5	277.931	0.16	0.90	95			80	80	60	1.0
	3								80	80	60	0.5

COMMENTS:

Ambient 70.9 ~~0~~

100 117
100 107
~~0~~ 4
250 257

Baghouse DP 2.0
2.0

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spurlock DATE: 6/16/05
SAMPLING TIME: (24 HR CLOCK) 1040 - 1153
SAMPLING LOCATION: Flyash Silo
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 80
TECHNICIAN: Taylor

Run 3
Flyash

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)			Ambient				20.9	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK [signature]
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER [signature]
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER [signature]

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	117	107	4				257	
INITIAL (ml)	100	100	0				250	
NET (ml)	17	7	4				7	35
TOTALS								35

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	571			WEIGHED BY	BEAKER NO.	12		Blank	WEIGHED BY
FINAL WEIGHT	0.1123			MT	FINAL WEIGHT	106.7704			MT
INITIAL WEIGHT	0.1120			CA	INITIAL WEIGHT	106.7692			
DIFFERENCE	0.0003			MT	DIFFERENCE	0.0012			
PARTICULATE CATCH	0.3			MT	PARTICULATE CATCH	1.2		0.2	

TOTAL PARTICULATE CATCH (mg) 1.3

Bottom Ash Silo Baghouse

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Bottom Ash Silo Baghouse

Run No: 1 Date: 6/14/05 Start Time: 9:08
End Time: 10:05

DIAMETER OF NOZZLE:	0.250		STACK DIMENSIONS:	32.5 x 15	inches
AREA OF NOZZLE:	3.409E-04	A_n	AREA OF STACK:	3.4	sq. ft.
BAROMETRIC PRESSURE:	29.85	P_{bar}	VOLUME OF MOISTURE:	15	V_{lc}
GAS METER Y-FACTOR:	0.98	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		45.662										
A-1	2.5	47.0	0.38	1.30	107	107	148				15.20	37.3
2	2.5	48.9	0.35	1.20	106	106	150	0.0	20.9	0.15	14.61	35.9
3	2.5	50.7	0.40	1.35	106	106	150				15.62	38.4
4	2.5	52.1	0.34	1.15	106	106	150				14.40	35.4
5	2.5	53.959	0.32	1.10	105	105	139				13.84	34.0
		53.959										
B-1	2.5	56.0	0.40	1.35	105	105	150				15.62	38.4
2	2.5	57.4	0.39	1.30	105	105	155				15.49	38.0
3	2.5	58.9	0.46	1.55	104	104	154				16.81	41.3
4	2.5	61.1	0.42	1.40	104	104	152				16.03	39.4
5	2.5	62.690	0.25	0.85	104	104	130				12.14	29.8
		62.690										
C-1	2.5	64.8	0.48	1.60	103	103	141				16.98	41.7
2	2.5	66.7	0.48	1.60	103	103	144				17.03	41.8
3	2.5	68.8	0.44	1.50	103	103	145				16.32	40.1
4	2.5	70.3	0.44	1.50	103	103	143				16.29	40.0
5	2.5	71.852	0.29	0.98	103	103	129				13.07	32.1
		71.852										
D-1	2.5	73.3	0.44	1.50	102	102	140				16.25	39.9
2	2.5	75.5	0.46	1.55	102	102	146				16.70	41.0
3	2.5	77.1	0.25	0.84	102	102	147				12.32	30.2
4	2.5	78.3	0.13	0.44	101	101	143				8.85	21.7
5	2.5	79.205	0.13	0.44	101	101	122				8.70	21.4
		79.205										
E-1	2.5	81.0	0.45	1.50	100	100	137				16.39	40.2
2	2.5	82.8	0.38	1.30	100	100	138				15.07	37.0
3	2.5	84.7	0.40	1.35	101	101	140				15.49	38.0
4	2.5	86.4	0.35	1.20	100	100	141				14.50	35.6
5	2.5	87.767	0.29	0.98	100	100	130				13.08	32.1
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	62.5	42.105	0.597	1.233		103	143	0.0	20.9	0.15	14.67	36.0
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.86	$V_{m(std)}$ =	38.706	$V_{w(std)}$ =	0.707	%M=	1.79
B_{ws} =	0.018	M_d =	28.84	M_s =	28.64		

STACK GAS VELOCITY =	36.0	AFPS	V_s
STACK GAS VELOCITY =	2,162	AFPM	
STACK GAS VOLUME =	6,312	DSCFM	Q_{std}
STACK GAS VOLUME =	7,350	ACFM	Q_a
ISOKINETIC RATIO =	97.9	%	

EMISSIONS

Weight, mg =	2.5
GR/DSCM =	0.001
GR/DSCM =	0.035
LBS/HR =	0.05

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Bottom Ash Silo Baghouse

Run No: **2** Date: 6/14/05 Start Time: 10:20
End Time: 11:33

DIAMETER OF NOZZLE:	0.250		STACK DIMENSIONS:	32.5 x 15	inches
AREA OF NOZZLE:	3.409E-04	A_n	AREA OF STACK:	3.4	sq. ft.
BAROMETRIC PRESSURE:	29.85	P_{bar}	VOLUME OF MOISTURE:	22	V_{lc}
GAS METER Y-FACTOR:	0.98	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		88.001										
E-1	2.5	90.0	0.36	1.20	99	99	146				14.77	36.3
2	2.5	91.7	0.42	1.40	99	99	152	0.0	20.9	0.15	16.03	39.4
3	2.5	93.3	0.38	1.30	99	99	153				15.26	37.5
4	2.5	95.1	0.45	1.50	99	99	146				16.51	40.6
5	2.5	96.795	0.37	1.25	99	99	122				14.67	36.1
		96.795										
D-1	2.5	98.8	0.41	1.40	99	99	143				15.72	38.7
2	2.5	100.3	0.34	1.15	99	99	150				14.40	35.4
3	2.5	101.9	0.37	1.25	99	99	150				15.02	37.0
4	2.5	103.6	0.37	1.25	99	99	148				15.00	36.9
5	2.5	105.325	0.37	1.25	99	99	121				14.66	36.1
		105.325										
C-1	2.5	107.1	0.43	1.45	99	99	139				16.05	39.5
2	2.5	109.0	0.39	1.30	99	99	145				15.36	37.8
3	2.5	110.7	0.39	1.30	99	99	144				15.35	37.8
4	2.5	112.4	0.38	1.30	100	100	137				15.06	37.1
5	2.5	114.026	0.35	1.20	100	100	119				14.24	35.0
		114.026										
B-1	2.5	115.9	0.40	1.35	100	100	136				15.44	38.0
2	2.5	117.0	0.15	0.51	100	100	147				9.54	23.5
3	2.5	118.1	0.15	0.51	100	100	145				9.53	23.4
4	2.5	119.2	0.15	0.51	100	100	142				9.50	23.4
5	2.5	120.172	0.15	0.51	100	100	118				9.31	22.9
		120.172										
A-1	2.5	122.3	0.50	1.70	100	100	130				17.18	42.3
2	2.5	123.9	0.38	1.30	100	100	138				15.07	37.1
3	2.5	125.9	0.44	1.50	100	100	138				16.22	39.9
4	2.5	127.6	0.37	1.25	100	100	138				14.87	36.6
5	2.5	127.092	0.29	0.98	101	101	127				13.05	32.1
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	62.5	39.091	0.585	1.185		100	139	0.0	20.9	0.15	14.31	35.2
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.86	$V_{m(std)}$ =	36.157	$V_{w(std)}$ =	1.036	%M=	2.79
B_{ws} =	0.028	M_d =	28.84	M_s =	28.53		

STACK GAS VELOCITY =	35.2	AFPS	V_s
STACK GAS VELOCITY =	2,113	AFPM	
STACK GAS VOLUME =	6,144	DSCFM	Q_{std}
STACK GAS VOLUME =	7,183	ACFM	Q_a
ISOKINETIC RATIO =	94.0	%	

EMISSIONS

Weight, mg =	2.5
GR/DSCM =	0.001
GR/DSCM =	0.038
LBS/HR =	0.06

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Bottom Ash Silo Baghouse

Run No: **3** Date: 6/14/05 Start Time: 11:50
End Time: 13:02

DIAMETER OF NOZZLE:	0.250		STACK DIMENSIONS:	32.5 x 15	inches
AREA OF NOZZLE:	3.409E-04	A_n	AREA OF STACK:	3.4	sq. ft.
BAROMETRIC PRESSURE:	29.85	P_{bar}	VOLUME OF MOISTURE:	25	V_{lc}
GAS METER Y-FACTOR:	0.98	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		129.295										
A-1	2.5	131.1	0.32	1.10	102	102	145				13.91	34.3
2	2.5	132.9	0.41	1.40	102	102	150	0.0	20.9		15.81	38.9
3	2.5	135.1	0.50	1.70	103	103	149			0.15	17.45	43.0
4	2.5	136.7	0.35	1.20	103	103	146				14.56	35.9
5	2.5	138.110	0.35	1.20	103	103	134				14.42	35.5
		138.110										
B-1	2.5	139.4	0.35	1.20	103	103	139				14.48	35.6
2	2.5	141.4	0.40	1.35	103	103	144				15.54	38.3
3	2.5	143.7	0.43	1.45	103	103	144				16.12	39.7
4	2.5	145.5	0.40	11.35	104	104	143				15.53	38.2
5	2.5	146.910	0.30	1.00	104	104	121				13.20	32.5
		146.910										
C-1	2.5	147.8	0.11	0.37	103	103	133				8.08	19.9
2	2.5	148.8	0.15	0.51	103	103	141				9.49	23.4
3	2.5	150.0	0.15	0.51	103	103	139				9.48	23.3
4	2.5	151.0	0.15	0.51	103	103	136				9.46	23.3
5	2.5	152.131	0.15	0.51	102	102	121				9.34	23.0
		152.131										
D-1	2.5	153.5	0.25	0.85	101	101	127				12.11	29.8
2	2.5	155.6	0.43	1.45	101	101	134				15.98	39.3
3	2.5	157.2	0.40	1.35	101	101	136				15.44	38.0
4	2.5	158.8	0.36	1.20	101	101	135				14.64	36.0
5	2.5	159.963	0.15	0.51	101	101	115				9.29	22.9
		159.963										
D-1	2.5	161.7	0.44	1.50	100	100	129				16.10	39.6
2	2.5	163.4	0.41	1.40	101	101	135				15.62	38.5
3	2.5	165.3	0.41	1.40	101	101	137				15.65	38.5
4	2.5	166.9	0.34	1.15	101	101	135				14.22	35.0
5	2.5	168.615	0.31	1.05	101	101	121				13.42	33.0
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	62.5	38.720	0.556	1.489		102	136	0.0	20.9	0.15	13.57	33.4
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.86	$V_{m(std)}$ =	35.675	$V_{w(std)}$ =	1.178	%M=	3.20
B_{ws} =	0.032	M_d =	28.84	M_s =	28.49		

STACK GAS VELOCITY =	33.4	AFPS	V_s
STACK GAS VELOCITY =	2,005	AFPM	
STACK GAS VOLUME =	5,839	DSCFM	Q_{std}
STACK GAS VOLUME =	6,817	ACFM	Q_a
ISOKINETIC RATIO =	97.6	%	

EMISSIONS

Weight, mg =	1.9
GR/DSCM =	0.001
GR/DSCM =	0.029
LBS/HR =	0.04

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 21	Filter Number	567
Plant	Spurlock	Nozzle No.	27	Initial Leak (Samp.)	0.000 @ 15"
Location	Bottom Ash Baghouse	Nozzle Dn.	0.250	Initial Leak (Pitot)	0 @ 25"
Test	PM - M17	TC No.	CAM 21		0 @ 2.5"
Run	1	P_B	29.85		
Date	6-14-05	Ambient Temp	85	Final Leak (Samp.)	0.001 @ 5"
Meter Box	070	Static	0.15	Final Leak (Pitot)	0 @ 5"
ΔH	1.64 | Y_1 0.98				0 @ 4"

K = 3.39

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	0904		45.662				NA	NA				
A 1		2.5	47.0	0.38	1.30	148			107	107	63	1.5
2		5.0	48.9	0.35	1.20	150			106	106	64	1.5
3		7.5	50.7	0.40	1.35	150			106	106	63	1.5
4		10.0	52.1	0.34	1.15	150			106	106	60	1.5
5	0917	12.5	53.959	0.32	1.10	139			105	105	60	1.0
B 1	0918	2.5	56.0	0.40	1.35	150			105	105	66	1.5
2		5.0	57.4	0.39	1.30	155			105	105	62	1.5
3		7.5	58.9	0.46	1.55	154			104	104	60	1.5
4		10.0	61.1	0.42	1.40	152			104	104	60	1.5
5	0931	12.5	62.690	0.25	0.85	130			104	104	58	1.0
C 1	0933	2.5	64.8	0.48	1.60	141			103	103	63	2.0
2		5.0	66.7	0.48	1.60	144			103	103	62	2.0
3		7.5	68.8	0.44	1.50	145			103	103	61	2.0
4		10.0	70.3	0.44	1.50	143			103	103	61	2.0
5	0936	12.5	71.852	0.29	0.98	129			103	103	61	1.0
D 1	0937	2.5	73.3	0.44	1.50	140			102	102	65	1.5
2		5.0	75.5	0.46	1.55	146			102	102	62	1.5
3		7.5	77.1	0.25	0.84	147			102	102	63	1.0
4		10.0	78.3	0.13	0.44	143			101	101	62	0.5
5	0950	12.5	79.205	0.13	0.44	122			101	101	62	0.5
E 1	0952	2.5	81.0	0.45	1.50	137			100	100	66	2.0
2		5.0	82.8	0.38	1.30	138			100	100	66	2.0
3		7.5	84.7	0.40	1.35	140			101	101	65	2.0
4		10.0	86.4	0.35	1.20	141			100	100	65	2.0
5		12.5	87.767	0.29	0.98	130			100	100	64	1.0
	1005											

COMMENTS:

Ambient
20.9
0

100 102
100 101
0 1
250 241

Baghouse
Δp 3.0"

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/14/05
SAMPLING TIME: (24 HR CLOCK) 0904 - 1005
SAMPLING LOCATION: Bottom Ash Silo
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 85
TECHNICIAN: Taylor

Run 1
Bottom Ash

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2			Ambient				0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							20.9	Fuel Type	Fo (calc)
								RESIDUAL FUEL OIL	1.280
								NATURAL GAS	1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	102	101	1				261	
INITIAL (ml)	100	100	0				250	
NET (ml)	2	1	1				11	15
TOTALS								15

PARTICULATE CATCH

FILTER WEIGHTS

FILTER NO.	567			WEIGHED BY
FINAL WEIGHT	0.1112			
INITIAL WEIGHT	0.1104			
DIFFERENCE	0.0008			
PARTICULATE CATCH	0.8			

PROBE/NOZZLE WASH

BEAKER NO.	11		Blank	WEIGHED BY
FINAL WEIGHT	106.4500		110.4567	MT
INITIAL WEIGHT	106.4481		110.4565	
DIFFERENCE	0.0019		0.0002	
PARTICULATE CATCH	1.9		0.2	

TOTAL PARTICULATE CATCH (mg) 2.5

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 21	Filter Number	569
Plant	Spurlock 3	Nozzle No.	CAM 25	Initial Leak (Samp.)	0.000 @ 15"
Location	Bottom Ash Baghouse	Nozzle Dn.	0.250	Initial Leak (Pitot)	0 @ 4"
Test	PM - M17	TC No.	CAM 21		0 @ 5"
Run	2	P_B	29.85		
Date	6-14-05	Ambient Temp	85	Final Leak (Samp.)	0.000@5"
Meter Box	070	Static	0.15	Final Leak (Pitot)	0 @ 3"
ΔH	1.64 | Y_1 0.98				0 @ 2.5"

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1020		88.001				NA	NA				
E 1		2.5	90.0	0.36	1.20	146			99	99	66	1.5
2		5.0	91.7	0.42	1.40	152			99	99	63	1.5
3		7.5	93.3	0.38	1.30	153			99	99	64	1.5
4		10.0	95.1	0.45	1.50	146			99	99	61	2.0
5	1033	12.5	96.795	0.37	1.25	122			99	99	57	1.5
D 1	1035	2.5	98.8	0.41	1.40	143			99	99	61	1.5
2		5.0	100.3	0.34	1.15	150			99	99	56	1.5
3		7.5	101.9	0.37	1.25	150			99	99	55	1.5
4		10.0	103.6	0.37	1.25	148			99	99	55	1.5
5	1048	12.5	105.325	0.37	1.25	121			99	99	56	1.5
C 1	1050	2.5	107.1	0.43	1.45	139			99	99	62	2.0
2		5.0	109.0	0.39	1.30	145			99	99	58	1.5
3		7.5	110.7	0.39	1.30	144			99	99	57	1.5
4		10.0	112.4	0.38	1.30	137			100	100	57	1.5
5	1103	12.5	114.024	0.35	1.20	119			100	100	57	1.5
B 1	1105	2.5	115.9	0.40	1.35	136			100	100	65	1.5
2		5.0	117.0	0.15	0.51	147			100	100	60	0.5
3		7.5	118.1	0.15	0.51	145			100	100	61	0.5
4		10.0	119.2	0.15	0.51	142			100	100	62	0.5
5	1118	12.5	120.172	0.15	0.51	118			100	100	60	0.5
A 1	1120	2.5	122.3	0.50	1.70	130			100	100	61	2.0
2		5.0	123.9	0.38	1.30	138			100	100	54	1.5
3		7.5	125.9	0.44	1.50	138			100	100	54	1.5
4		10.0	127.6	0.37	1.25	138			100	100	54	1.5
5	1133	12.5	127.092	0.29	0.98	127			101	101	55	1.0

COMMENTS:

ambient 100 110
20 g 100 101
0 2
0 250 259

Baghouse
ΔP 3.0"

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/14/05
SAMPLING TIME: (24 HR CLOCK) 1020 - 1133
SAMPLING LOCATION: Bottom Ash Silo
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/7 AMB. TEMP (°F) 85
TECHNICIAN: Taylor

Run 2
Bottom Ash

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = 20.9 − %O2 / %CO2	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)			ambient				20.9	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK [illegible]
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER [illegible]
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER [illegible]

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	110	101	2				259	
INITIAL (ml)	100	100	0				250	
NET (ml)	10	1	2				9	22
TOTALS								22

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	569			WEIGHED BY	BEAKER NO.	19		Blank	WEIGHED BY
FINAL WEIGHT	0.1140			MT	FINAL WEIGHT	109.0666			MT
INITIAL WEIGHT	0.1124			CA	INITIAL WEIGHT	109.0655			
DIFFERENCE	0.0016			MT	DIFFERENCE	0.0011			
PARTICULATE CATCH	1.6			MT	PARTICULATE CATCH	1.1		0.2	

TOTAL PARTICULATE CATCH (mg) 2.5

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM21	Filter Number	565
Plant	Spurlock 3	Nozzle No.	CAM 30	Initial Leak (Samp.)	0.020 @ 13
Location	Bottom Ash Baghouse	Nozzle Dn.	0.250	Initial Leak (Pitot)	ok @ 3"
Test	PM - M17	TC No.	CAM21		ok @ 2.5"
Run	3	P_B	29.85		
Date	6-14-05	Ambient Temp	85	Final Leak (Samp.)	0.030 @ 3"
Meter Box	070	Static	0.15	Final Leak (Pitot)	ok @ 2.0
ΔH	1.64 | Y_1 0.98				ok @ 2.0"

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	1150		129.295				NA	NA				
A1		2.5	131.1	0.32	1.10	145			102	102	64	1.0
2		5.0	132.9	0.41	1.40	150			102	102	65	1.5
3		7.5	135.1	0.50	1.70	149			103	103	63	2.0
4		10.0	136.7	0.35	1.20	146			103	103	63	1.5
5	1203	12.5	138.110	0.35	1.20	134			103	103	63	1.5
B1	1205	2.5	139.4	0.35	1.20	139			103	103	66	1.5
2		5.0	141.4	0.40	1.35	144			103	103	64	1.5
3		7.5	143.7	0.43	1.45	144			103	103	63	2.0
4		10.0	145.5	0.40	1.35	143			104	104	60	2.0
5	1218	12.5	146.910	0.30	1.00	121			104	104	60	1.5
C1	1220	2.5	147.8	0.11	0.37	133			103	103	63	0.5
2		5.0	148.8	0.15	0.51	141			103	103	61	0.5
3		7.5	150.0	0.15	0.51	139			103	103	61	0.5
4		10.0	151.0	0.15	0.51	136			103	103	60	0.5
5	1233	12.5	152.131	0.15	0.51	121			102	102	63	0.5
D1	1234	2.5	153.5	0.25	0.85	127			101	101	65	0.5
2		5.0	155.6	0.43	1.45	134			101	101	63	1.5
3		7.5	157.2	0.40	1.35	136			101	101	58	1.5
4		10.0	158.8	0.36	1.20	135			101	101	57	1.5
5	1246	12.5	159.963	0.15	0.51	115			101	101	57	0.5
E1	1249	2.5	161.7	0.44	1.50	129			100	100	63	2.0
2		5.0	163.4	0.41	1.40	135			101	101	58	2.0
3		7.5	165.3	0.41	1.40	137			101	101	59	2.0
4		10.0	166.9	0.34	1.15	135			101	101	58	1.0
5	1302	12.5	168.615	0.31	1.05	121			101	101	60	1.0

COMMENTS:

Ambient
209
b

100 103
100 104
b 2
250 261

Baghouse
DP
3.0
2.0

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/14/05
SAMPLING TIME: (24 HR CLOCK) 1150 - 1302
SAMPLING LOCATION: Bottom Ash
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 85
TECHNICIAN: Taylor

Run 3
Bottom Ash

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							t		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)			Ambient				20.9	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ok
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER ok
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 21.0 / 21.0 BUBBLER ok

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	108	104	2				261	
INITIAL (ml)	100	100	0				250	
NET (ml)	8	4	2				11	25
TOTALS								25

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	565			WEIGHED BY	BEAKER NO.	60		Blank	WEIGHED BY
FINAL WEIGHT	0.1117			MT	FINAL WEIGHT	107.8212			MT
INITIAL WEIGHT	0.1113			CA	INITIAL WEIGHT	107.8195			
DIFFERENCE	0.0004			MT	DIFFERENCE	0.0017			
PARTICULATE CATCH	0.4			MT	PARTICULATE CATCH	1.7		0.2	

TOTAL PARTICULATE CATCH (mg) 1.9

Limestone Baghouse

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Limestone Baghouse

Run No: **1** Date: 6/15/05 Start Time: 7:50
End Time: 8:53

DIAMETER OF NOZZLE:	0.220		STACK DIAMETER:	27	inches
AREA OF NOZZLE:	2.640E-04	A_n	AREA OF STACK:	4.0	sq. ft.
BAROMETRIC PRESSURE:	29.55	P_{bar}	VOLUME OF MOISTURE:	24	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		625.002										
A-1	2.5	627.0	0.77	1.65	86	87	99				20.75	51.3
2	2.5	628.9	0.70	1.55	85	87	98	0.0	20.9	-0.32	19.76	48.9
3	2.5	630.6	0.75	1.65	85	88	98				20.46	50.6
4	2.5	632.2	0.75	1.65	86	88	99				20.48	50.6
5	2.5	634.3	0.69	1.50	86	87	98				19.62	48.5
6	2.5	636.0	0.70	1.55	87	88	98				19.76	48.9
7	2.5	638.4	0.89	1.95	88	89	98				22.28	55.1
8	2.5	640.3	0.97	2.10	89	89	99				23.29	57.6
9	2.5	642.0	1.10	2.40	89	90	98				24.77	61.3
10	2.5	644.1	1.00	2.20	90	90	93				23.52	58.1
11	2.5	646.4	0.81	1.75	90	90	89				21.09	52.1
12	2.5	647.388	0.26	0.57	90	90	85				11.90	29.4
		647.388										
B-1	2.5	649.3	1.20	2.60	90	91	97				25.85	63.9
2	2.5	652.0	1.15	2.50	91	92	98				25.33	62.6
3	2.5	654.2	1.15	2.50	91	92	98				25.33	62.6
4	2.5	656.7	1.15	2.50	92	92	98				25.33	62.6
5	2.5	658.8	1.10	2.40	92	92	98				24.77	61.3
6	2.5	661.0	1.05	2.30	92	92	97				24.18	59.8
7	2.5	663.0	1.05	2.30	93	93	97				24.18	59.8
8	2.5	665.2	0.97	2.10	93	93	97				23.24	57.5
9	2.5	667.6	1.10	2.40	94	94	96				24.73	61.1
10	2.5	669.6	1.00	2.20	94	94	95				23.56	58.2
11	2.5	671.8	0.69	1.50	93	93	89				19.46	48.1
12	2.5	672.805	0.25	0.55	93	93	82				11.64	28.8
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	47.803	0.928	1.932		90	96	0.0	20.9	-0.32	21.89	54.1
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.53	$V_{m(std)}$ =	45.501	$V_{w(std)}$ =	1.130	%M=	2.42
B_{ws} =	0.024	M_d =	28.84	M_s =	28.57		

STACK GAS VELOCITY =	54.1	AFPS	V_s
STACK GAS VELOCITY =	3,247	AFPM	
STACK GAS VOLUME =	11,885	DSCFM	Q_{std}
STACK GAS VOLUME =	12,987	ACFM	Q_a
ISOKINETIC RATIO =	96.7	%	

EMISSIONS

Weight, mg =	2.0
GR/DSCF =	0.001
GR/DSCM	0.024
LBS/HR =	0.07

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Limestone Baghouse

Run No: **2** Date: 6/15/05 Start Time: 9:18
End Time: 10:21

DIAMETER OF NOZZLE:	0.220		STACK DIAMETER:	27	inches
AREA OF NOZZLE:	2.640E-04	A_n	AREA OF STACK:	4.0	sq. ft.
BAROMETRIC PRESSURE:	29.55	P_{bar}	VOLUME OF MOISTURE:	26	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP	CO2%	O2%	STATIC PRESS	SDE	VEL
		673.065										
B-1	2.5	675.8	1.20	2.60	91	94	99				25.90	64.1
2	2.5	677.6	1.20	2.60	92	95	99	0.0	20.9	-0.32	25.90	64.1
3	2.5	680.0	1.20	2.60	92	94	99				25.90	64.1
4	2.5	682.3	1.20	2.60	93	94	99				25.90	64.1
5	2.5	684.9	1.15	2.50	93	94	99				25.35	62.7
6	2.5	687.0	1.10	2.40	93	94	99				24.80	61.3
7	2.5	689.0	0.95	2.10	94	94	98				23.02	56.9
8	2.5	691.1	0.95	2.10	94	94	98				23.02	56.9
9	2.5	693.1	1.05	2.30	94	95	97				24.18	59.8
10	2.5	695.3	1.05	2.30	94	95	93				24.10	59.6
11	2.5	697.4	0.85	1.85	94	94	88				21.58	53.4
12	2.5	698.840	0.36	0.78	94	94	85				14.01	34.6
		698.840										
A-1	2.5	100.6	0.71	1.55	93	94	97				19.89	49.2
2	2.5	702.3	0.71	1.55	93	94	98				19.90	49.2
3	2.5	704.3	0.77	1.65	94	94	98				20.73	51.3
4	2.5	706.1	0.73	1.60	94	94	97				20.16	49.9
5	2.5	707.9	0.71	1.55	94	94	97				19.89	49.2
6	2.5	709.7	0.80	1.75	93	93	97				21.11	52.2
7	2.5	712.1	1.00	2.20	93	93	97				23.60	58.4
8	2.5	714.1	1.10	2.40	93	94	97				24.75	61.2
9	2.5	716.2	1.10	2.40	94	95	97				24.75	61.2
10	2.5	718.5	1.00	2.20	95	96	95				23.56	58.3
11	2.5	720.4	0.95	1.95	95	96	94				22.94	56.7
12	2.5	722.066	0.45	1.00	95	95	89				15.72	38.9
RESULTS	TT	VM	SQRT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	49.001	0.955	2.022		94	96	0.0	20.9	-0.32	22.53	55.7
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.53	$V_{m(std)}$ =	46.346	$V_{w(std)}$ =	1.225	%M=	2.57
B_{ws} =	0.026	M_d =	28.84	M_s =	28.56		

STACK GAS VELOCITY =	55.7	AFPS	V_s	EMISSIONS	
STACK GAS VELOCITY =	3,343	AFPM		Weight, mg =	2.1
STACK GAS VOLUME =	12,206	DSCFM	Q_{std}	GR/DSCF =	0.001
STACK GAS VOLUME =	13,371	ACFM	Q_a	GR/DSCM	0.025
ISOKINETIC RATIO =	95.9	%		LBS/HR =	0.07

Catalyst Air Management, Inc.
Method 17 Isokinetic Sample Sheet

Client: **East Kentucky Power Cooperative**
Unit Tested: **Spurlock 3**
Sampling Location: Limestone Baghouse

Run No: **3** Date: 6/15/05 Start Time: 10:43
End Time: 11:46

DIAMETER OF NOZZLE:	0.220		STACK DIAMETER:	27	inches
AREA OF NOZZLE:	2.640E-04	A_n	AREA OF STACK:	4.0	sq. ft.
BAROMETRIC PRESSURE:	29.55	P_{bar}	VOLUME OF MOISTURE:	25	V_{lc}
GAS METER Y-FACTOR:	1.00	Y	PITOT COEFFICIENT:	0.84	C_p

POINT	TIME	GAS METER	VEL HEAD	PM ORIFICE	METER TEMP IN	METER TEMP OUT	STACK TEMP.	CO2%	O2%	STATIC PRESS.	SDE	VEL
		722.344										
A-1	2.5	724.1	0.72	1.55	93	95	98				20.04	49.6
2	2.5	725.8	0.72	1.55	94	95	99	0.0	20.9	-0.32	20.06	49.6
3	2.5	727.7	0.75	1.65	94	96	99				20.48	50.6
4	2.5	730.0	0.75	1.65	94	94	98				20.46	50.6
5	2.5	731.4	0.77	1.65	95	96	99				20.75	51.3
6	2.5	733.5	0.85	1.85	95	95	99				21.80	53.9
7	2.5	735.6	1.10	2.40	95	94	99				24.80	61.3
8	2.5	738.0	1.15	2.50	95	95	99				25.35	62.7
9	2.5	740.1	1.15	2.50	95	95	98				25.33	62.6
10	2.5	742.6	1.10	2.40	95	95	95				24.71	61.1
11	2.5	744.6	0.88	1.90	96	96	94				22.08	54.6
12	2.5	746.095	0.40	0.87	96	95	89				14.82	36.6
		746.095										
B-1	2.5	748.1	1.20	2.60	94	93	97				25.85	63.9
2	2.5	750.5	1.20	2.60	95	95	99				25.90	64.0
3	2.5	753.1	1.20	2.60	95	95	99				25.90	64.0
4	2.5	755.3	1.15	2.50	95	94	99				25.35	62.7
5	2.5	757.3	1.10	2.40	95	94	99				24.80	61.3
6	2.5	759.8	1.00	2.20	95	95	98				23.62	58.4
7	2.5	761.8	0.90	1.95	95	94	98				22.41	55.4
8	2.5	764.0	0.95	2.05	95	95	98				23.02	56.9
9	2.5	765.8	0.98	2.15	95	95	97				23.36	57.8
10	2.5	768.2	1.10	2.40	96	96	97				24.75	61.2
11	2.5	770.1	0.98	2.15	97	95	92				23.26	57.5
12	2.5	772.015	0.50	1.10	96	95	90				16.58	41.0
RESULTS	TT	VM	SQ RT PIT	PM		TM	TS	CO2	O2	STATIC	SDE	VEL
	60.0	49.671	0.963	2.049		95	97	0.0	20.9	-0.32	22.73	56.2
	net	net	avg	avg		avg	avg	avg	avg	avg	avg	ft/sec

P_s =	29.53	$V_{m(std)}$ =	46.895	$V_{w(std)}$ =	1.178	%M=	2.45
B_{ws} =	0.024	M_d =	28.84	M_s =	28.57		

STACK GAS VELOCITY =	56.2	AFPS	V_s
STACK GAS VELOCITY =	3,372	AFPM	
STACK GAS VOLUME =	12,307	DSCFM	Q_{std}
STACK GAS VOLUME =	13,487	ACFM	Q_a
ISOKINETIC RATIO =	96.3	%	

EMISSIONS

Weight, mg =	2.2
GR/DSCF =	0.001
GR/DSCM	0.026
LBS/HR =	0.08

CATALYST AIR MANAGEMENT, INC.
Air Quality Testing Services
2505 Byington Solway Road
Knoxville, TN 37931
(865) 531-0075
(865) 531-0750 Fax

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 21	Filter Number	570
Plant	Spurlock 3	Nozzle No.	CAM 50	Initial Leak (Samp.)	0.000 @ 13"
Location	Limestone Baghouse	Nozzle Dn.	0.220	Initial Leak (Pitot)	ok @ 3.5
Test	PM - M17	TC No.	CAM 21		ok @ 4.0
Run	1	P_B	29.55		
Date	6-15-05	Ambient Temp	76	Final Leak (Samp.)	0.002 @ 7"
Meter Box	030	Static	-0.32	Final Leak (Pitot)	ok @ 3.0
Δ H	1.67 | Y_1 1.00				ok @ 3.0

K = 2.18

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
	0750		625.002				NA	NA				
A1		2.5	627.0	0.77	1.65	99			86	87	65	2.0
2		5.0	628.9	0.70	1.55	98			85	87	64	2.0
3		7.5	630.6	0.75	1.65	98			85	88	62	2.0
4		10.0	632.2	0.75	1.65	99			86	88	64	2.0
5		12.5	634.3	0.69	1.50	98			86	87	64	2.0
6		15.0	636.0	0.70	1.55	98			87	88	64	2.0
7		17.5	638.4	0.89	1.95	98			88	89	62	3.0
8		20.0	640.3	0.97	2.10	99			89	89	61	3.0
9		22.5	642.0	1.10	2.40	98			89	90	60	3.5
10		25.0	644.1	1.00	2.20	93			90	90	59	3.5
11		27.5	646.4	0.81	1.75	89			90	90	58	3.0
12	0820	30.0	647.388	0.26	0.57	85			90	90	58	0.5
	0823											
B1		2.5	649.3	1.20	2.60	97			90	91	64	3.5
2		5.0	652.0	1.15	2.50	98			91	92	56	3.5
3		7.5	654.2	1.15	2.50	98			91	92	56	3.5
4		10.0	656.7	1.15	2.50	98			92	92	57	3.5
5		12.5	658.8	1.10	2.40	98			92	92	58	3.5
6		15.0	661.0	1.05	2.30	97			92	92	58	3.5
7		17.5	663.0	1.05	2.30	97			93	93	56	3.5
8		20.0	665.2	0.97	2.10	97			93	93	57	3.0
9		22.5	667.6	1.10	2.40	96			94	94	58	3.5
10		25.0	669.6	1.00	2.20	95			94	94	58	3.5
11		27.5	671.8	0.69	1.50	89			93	93	57	2.5
12	0853	30.0	672.805	0.25	0.55	82			93	93	57	0.5

COMMENTS:

Ambient
20.9
0

100 108
100 104
0 2
250 260

Baghouse
ΔP
1.6

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/15/05
SAMPLING TIME: (24 HR CLOCK) 0750 - 0853
SAMPLING LOCATION: Limestone
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 76
TECHNICIAN: Taylor

Run 1
Limestone

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO_2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2			Ambient				0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							20.9	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.9 / 20.9 BUBBLER ✓
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.9 / 20.9 BUBBLER ✓

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	109	104	2				260	
INITIAL (ml)	100	100	0				250	
NET (ml)	8	4	2				10	24
TOTALS								24

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	570			WEIGHED BY	BEAKER NO.	08		Blank	WEIGHED BY
FINAL WEIGHT	0.1124			MT	FINAL WEIGHT	107.8389		110.4567	MT
INITIAL WEIGHT	0.1114			CA	INITIAL WEIGHT	107.8377		110.4565	
DIFFERENCE	0.0010			MT	DIFFERENCE	0.0012		0.0002	
PARTICULATE CATCH	1.0			MT	PARTICULATE CATCH	1.2		0.2	

TOTAL PARTICULATE CATCH (mg) 2.0

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 21	Filter Number	568
Plant	Spurlock 3	Nozzle No.	CAM 50	Initial Leak (Samp.)	0.002 @ 14"
Location	Limestone Baghouse	Nozzle Dn.	0.220	Initial Leak (Pitot)	ok @ 30
Test	PM - M17	TC No.	CAM 21		ok @ 30"
Run	2	P_B	29.55		
Date	6-15-05	Ambient Temp	78	Final Leak (Samp.)	0.029 @ 4"
Meter Box	030	Static	-0.32	Final Leak (Pitot)	ok @ 35
ΔH	1.67 | Y_I 1.00				ok @ 4.0

POINT	TIME ACTUAL	TIME RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	METER °F OUT	EXIT °F	VAC
			673.065				NA	NA				
B1	0918	2.5	675.8	1.20	2.60	99			91	94	66	3.5
2		5.0	677.6	1.20	2.60	99			92	95	56	3.5
3		7.5	680.0	1.20	2.60	99			92	94	52	3.5
4		10.0	682.3	1.20	2.60	99			93	94	51	3.5
5		12.5	684.9	1.15	2.50	99			93	94	51	3.5
6		15.0	687.0	1.10	2.40	99			93	94	51	3.5
7		17.5	689.0	0.95	2.10	98			93	94	51	3.0
8		20.0	691.1	0.95	2.10	98			94	94	50	3.0
9		22.5	693.1	1.05	2.30	97			94	95	50	3.5
10		25.0	695.3	1.05	2.30	93			94	95	50	3.5
11		27.5	697.4	0.85	1.85	88			94	94	50	3.0
12	0948	30.0	698.840	0.36	0.78	85			94	94	50	1.0
	0951											
A1		2.5	700.6	0.71	1.55	97			93	94	57	2.0
2		5.0	702.3	0.71	1.55	98			93	94	54	2.0
3		7.5	704.3	0.77	1.65	98			94	94	55	2.5
4		10.0	706.1	0.73	1.60	97			94	94	55	2.5
5		12.5	707.9	0.71	1.55	97			94	94	56	2.5
6		15.0	709.7	0.80	1.75	97			93	93	58	3.0
7		17.5	712.1	1.00	2.20	97			93	93	58	3.0
8		20.0	714.1	1.10	2.40	97			93	94	57	3.5
9		22.5	716.2	1.10	2.40	97			94	95	56	3.5
10		25.0	718.5	1.00	2.20	95			95	96	57	3.0
11		27.5	720.4	0.90	1.95	94			95	96	58	3.0
12	1081	30.0	722.066	0.45	1.00	89			95	95	60	1.0

COMMENTS:

Ambient 20 9 ~~10~~

100 110
100 102
~~0~~ 4
264 274

Baghouse DP 1.55

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/15/05
SAMPLING TIME: (24 HR CLOCK) 0918 - 1021
SAMPLING LOCATION: Limestone
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 78
TECHNICIAN: Taylor

Run 2
Limestone

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2			Ambient				0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)							20.9	Fuel Type RESIDUAL FUEL OIL NATURAL GAS	Fo (calc) 1.280 1.716

SYSTEM LEAK CHECK ✓
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.9 / 20.9 BUBBLER ✓
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.9 / 20.9 BUBBLER ✓

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	110	102	4				274	
INITIAL (ml)	100	100	0				264	
NET (ml)	10	2	4				10	26
TOTALS								26

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	569			WEIGHED BY	BEAKER NO.	05		Blank	WEIGHED BY
FINAL WEIGHT	0.1122			MT	FINAL WEIGHT	103.0972			MT
INITIAL WEIGHT	0.1109			CA	INITIAL WEIGHT	103.0962			
DIFFERENCE	0.0013			MT	DIFFERENCE	~~0.000~~	0.0010		
PARTICULATE CATCH	1.3			MT	PARTICULATE CATCH	1.0		0.2	

TOTAL PARTICULATE CATCH (mg) 2.1

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington Solway Road
Knoxville, TN 37931

Field Isokinetic Data Sheet

Client	EKPC	Pitot No.	CAM 21	Filter Number	572
Plant	Spurlock 3	Nozzle No.	CAM 50	Initial Leak (Samp.)	0.002 @ 13"
Location	Limestone Baghouse	Nozzle Dn.	0.220	Initial Leak (Pitot)	ok @ 3.5
Test	PM MM	TC No.	CAM21		ok @ 3.5
Run	3	P_B	29.55		
Date	6-15-05	Ambient Temp	80	Final Leak (Samp.)	0.008 @ 7"
Meter Box	030	Static	-0.32	Final Leak (Pitot)	ok @ 3.5
ΔH	1.67 | Y_1 1.00				ok @ 4.0

POINT	TIME ACTUAL	RUN	METER	ΔP	Δh	STACK °F	PROBE °F	OVEN °F	METER °F IN	OUT	EXIT °F	VAC
	1043		722.344				NA	NA				
A1		2.5	724.1	0.72	1.55	98			93	95	65	2.0
2		5.0	725.8	0.72	1.55	99			94	95	63	2.0
3		7.5	727.7	0.75	1.65	99			94	96	59	2.0
4		10.0	730.0	0.75	1.65	98			94	94	57	2.0
5		12.5	731.4	0.77	1.65	99			95	96	56	2.0
6		15.0	733.5	0.85	1.85	99			95	95	56	2.5
7		17.5	735.6	1.10	2.40	99			95	94	55	3.5
8		20.0	738.0	1.15	2.50	99			95	95	54	3.5
9		22.5	740.1	1.15	2.50	98			95	95	52	3.5
10		25.0	742.6	1.10	2.40	95			95	95	53	3.5
11		27.5	744.4	0.88	1.90	94			96	96	53	3.0
12	1113	30.0	746.095	0.40	0.87	89			96	95	55	0.5
	1116											
B1		2.5	748.1	1.20	2.60	97			94	93	60	4.0
2		5.0	750.5	1.20	2.60	99			95	95	53	4.0
3		7.5	753.1	1.20	2.60	99			95	95	51	4.0
4		10.0	755.3	1.15	2.50	99			95	94	51	3.5
5		12.5	757.3	1.10	2.40	99			95	94	51	3.5
6		15.0	759.8	1.00	2.20	98			95	95	50	3.0
7		17.5	761.8	0.90	1.95	98			95	94	50	3.0
8		20.0	764.0	0.95	2.05	98			95	95	51	3.0
9		22.5	765.8	0.98	2.15	97			95	95	51	3.0
10		25.0	768.2	1.10	2.40	97			96	96	51	3.5
11		27.5	770.1	0.98	2.15	92			97	95	51	3.0
12	1146	30.0	772.015	0.50	1.10	90			96	95	53	1.0

COMMENTS:

Ambient
20.9
0

100 107
100 106
0 4
302 310

Baghouse
Δp
1.55

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

PLANT: Spunlock DATE: 6/15/05
SAMPLING TIME: (24 HR CLOCK) 1043 - 1146
SAMPLING LOCATION: Limestone
SAMPLING TYPE: Integrated Bag
ANALYTICAL METHOD: 3/17 AMB. TEMP (°F) 80
TECHNICIAN: Taylor

Run 3
Limestone

RUN / GAS	1		2		3		AVERAGE NET VOLUME	Fo (TEST) = $\frac{20.9 - \%O_2}{\%CO2}$	
	ACTUAL READING	NET	ACTUAL READING	NET	ACTUAL READING	NET			
CO_2							0		
O_2 (NET IS ACTUAL MINUS ACTUAL CO_2)			Ambient				20.9	Fuel Type: RESIDUAL FUEL OIL / NATURAL GAS	Fo (calc): 1.280 / 1.716

SYSTEM LEAK CHECK al
INITIAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.9 / 20.9 BUBBLER
FINAL ORSAT ANALYZER LEAK CHECK (FLUID LEVEL) 20.9 / 20.9 BUBBLER

MOISTURE

	1	2	3	4	5	6	GEL	TOTALS
FINAL (ml)	107	106	4				310	
INITIAL (ml)	100	100	0				302	
NET (ml)	7	6	4				8	25
TOTALS								25

PARTICULATE CATCH

FILTER WEIGHTS					PROBE/NOZZLE WASH				
FILTER NO.	572			WEIGHED BY	BEAKER NO.	27		Blank	WEIGHED BY
FINAL WEIGHT	0.1139			MT	FINAL WEIGHT	107.8205			MT
INITIAL WEIGHT	0.1125			CA	INITIAL WEIGHT	107.8195			
DIFFERENCE	0.0014			MT	DIFFERENCE	0.0010			
PARTICULATE CATCH	1.4			MT	PARTICULATE CATCH	1.0		0.2	

TOTAL PARTICULATE CATCH (mg) 2.2

APPENDIX 4
LABORATORY ANALYSIS

Trace Metals/HCl/HF/Acid Mist

Maxxam Analytics Inc

Driven by Service and Science

Catalyst Air Management
2505 Byington-Solway Rd
Knoxville, TN
USA 37931

Attention: Mike Taylor

Report Date: 2005/07/13

Your Project #: EKPC
Site: SPUNLOCK 3

ANALYTICAL REPORT

MAXXAM JOB #: A557722
Received: 2005/06/23, 12:00

Sample Matrix: Filter
Samples Received: 4

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Mercury - Filter and Acetone Rinse (1)	4	2005/06/30	2005/06/30	SOP ING-111	EPA CFR PTM 29
Total Metals Analysis on Comb. Train (1)	4	2005/06/29	2005/06/30	ING 109	SW 846 6020

Sample Matrix: Impinger Solution
Samples Received: 22

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Halogens by IC in Impingers (1)	5	2005/06/24	2005/06/24	SOP ING 211	EPA CFR PTM 26A
Mercury - HCl Impinger Solution (1)	4	2005/07/11	2005/07/11	SOP ING-111	EPA CFR PTM 29
Mercury - HNO3 Rinse Solution (1)	4	2005/07/05	2005/07/06	SOP ING-111	EPA CFR PTM 29
Mercury - HNO3/H2O2 Impinger Solution (1)	4	2005/07/05	2005/07/06	SOP ING-111	EPA CFR PTM 29
Mercury - KMnO4/H2SO4 Impinger Solution (1)	4	2005/07/07	2005/07/07	SOP ING-111	EPA CFR PTM 29
Hydrogen Halides by IC (1)	5	2005/07/11	2005/07/11	SOP ING 211	EPA CFR PTM 26A
Sulphuric Acid Mist - Titration (1)	4	2005/07/12	2005/07/12	NCASI--EPA 8a	
Sulphur Dioxide in Impingers - Titration (1)	4	2005/06/27	2005/06/28	NCASI--EPA 8a	

(1) This test was performed by Maxxam Analytics Burlington

MAXXAM ANALYTICS INC.

MIKE CHALLIS, CET, B.Sc, C.Chem
Customer Service Manager, US Air Toxics

MDC/mdc
encl.

Total cover pages: 1

Burlington:5555 North Service Road, Burlington, Ontario L7L 5H7 Telephone(905) 332-8788 Fax(905) 332-9169

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 29 Metals ICP/MS

Maxxam ID		G81318	G81368	G81368	G81369
Sampling Date		6/8/2005	6/8/2005	6/8/2005	6/8/2005
	Units	**M29-BLANK**	**M29-RUN#1**	**M29-RUN#1 Dup**	**M29-RUN#2**
Total Beryllium (Be)	ug	0.3	0.4	0.3	0.3
Total Lead (Pb)	ug	6.7	8.1	8	16.9

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 29 Metals ICP/MS

Maxxam ID		G81370			
Sampling Date		6/8/2005			
	Units	**M29-RUN#3**	**DL**	**QC Batch**	**MDL**
Total Beryllium (Be)	ug	0.3	0.1	769333	0.1
Total Lead (Pb)	ug	13.3	0.2	769333	0.2

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 29 Mercury

Maxxam ID		G81318		G81368	G81368	
Sampling Date		6/8/2005		6/8/2005	6/8/2005	
	Units	**M29-BLANK**	**DL**	**M29-RUN#1**	**M29-RUN#1 Dup**	**DL**
Total Mercury-1B-Filter/Acetone/Rinse	ug	<0.03	0.03	0.06	0.06	0.03
Total Mercury-3B-KMnO4	ug	<0.05	0.05	<0.05	<0.05	0.05
Total Mercury-2B Nitric/Peroxide	ug	<0.17	0.17	<0.62	<0.62	0.62
Total Mercury-3A Nitric Impinger	ug	<0.01	0.01	0.01	N/A	0.01
Total Mercury-3C HCl	ug	0.07	0.05	3.32	3.3	0.05

N/A = Not Applicable
QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 29 Mercury

Maxxam ID		G81369	G81369		G81370			
Sampling Date		6/8/2005	6/8/2005		6/8/2005			
	Units	**M29-RUN#2**	**M29-RUN#2 Dup**	**DL**	**M29-RUN#3**	**DL**	**QC Batch**	**MDL**
Total Mercury-1B-Filter/Acetone/Rinse	ug	0.16	N/A	0.03	<0.03	0.03	770520	0.03
Total Mercury-3B-KMnO4	ug	<0.05	N/A	0.05	<0.05	0.05	774522	0.05
Total Mercury-2B Nitric/Peroxide	ug	<0.58	N/A	0.58	<0.62	0.62	766380	0.01
Total Mercury-3A Nitric Impinger	ug	<0.01	<0.01	0.01	<0.01	0.01	766374	0.05
Total Mercury-3C HCl	ug	2.68	N/A	0.05	3.71	0.05	775459	0.05

N/A = Not Applicable
QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 26A

Maxxam ID		G81002	G81002	G81006	G81006
Sampling Date		6/9/2005	6/9/2005	6/9/2005	6/9/2005
	Units	**M26A-DI BLANK**	**M26A-DI BLANK Dup**	**M26A-BLANK H2SO4**	**M26A-BLANK H2SO4 Dup**
Hydrochloric Acid	ug	<100	<100	<100	<100
Hydrofluoric Acid	ug	<100	<100	<100	<100

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 26A

Maxxam ID		G81008	G81008	G81009	G81009
Sampling Date		6/9/2005	6/9/2005	6/9/2005	6/9/2005
	Units	**M26A-IMP 1/2-RUN#1**	**M26A-IMP 1/2-RUN#1 Dup**	**M26A-IMP 1/2-RUN#2**	**M26A-IMP 1/2-RUN#2 Dup**
Hydrochloric Acid	ug	<100	<100	<100	<100
Hydrofluoric Acid	ug	<100	<100	<100	<100

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 26A

Maxxam ID		G81010	G81010		
Sampling Date		6/9/2005	6/9/2005		
	Units	**M26A-IMP 1/2-RUN#3 H**	**M26A-IMP 1/2-RUN#3 Dup**	**QC Batch**	**MDL**
Hydrochloric Acid	ug	<100	<100	776755	100
Hydrofluoric Acid	ug	<100	<100	776755	100

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 26A

Maxxam ID		G81094	G81094	G81097	G81097
Sampling Date		6/9/2005	6/9/2005	6/9/2005	6/9/2005
	Units	**M26A-DI BLANK**	**M26A-DI BLANK Dup**	**M26A- BLANK NAOH**	**M26A- BLANK NAOH Dup**
Chlorine	ug	<100	<100	<100	<100
Fluorine	ug	<100	<100	<100	<100

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 26A

Maxxam ID		G81099	G81099	G81100	G81100
Sampling Date		6/9/2005	6/9/2005	6/9/2005	6/9/2005
	Units	**M26A-IMP 3/4-RUN#1**	**M26A-IMP 3/4-RUN#1 Dup**	**M26A-IMP 3/4-RUN#2**	**M26A-IMP 3/4-RUN#2 Dup**
Chlorine	ug	3200	3100	5000	4900
Fluorine	ug	<100	<100	<100	<100

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

Method 26A

Maxxam ID		G81101	G81101		
Sampling Date		6/9/2005	6/9/2005		
	Units	**M26A-IMP 3/4-RUN#3**	**M26A-IMP 3/4-RUN#3 Dup**	**QC Batch**	**MDL**
Chlorine	ug	2100	2100	766677	100
Fluorine	ug	<100	<100	766677	100

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

RESULTS OF ANALYSES OF IMPINGER SOLUTION

Maxxam ID		G81183		G81227		G81228	
Sampling Date		6/9/2005		6/9/2005		6/9/2005	
	Units	**M8-80% IPA BLANK**	**DL**	**M8-FRONT HALF-RUN#1**	**DL**	**M8-FRONT HALF-RUN#2**	**DL**
Sulphuric Acid Mist	mg	<0.13	0.13	7.3	0.25	7.7	0.24
Sulphur dioxide	mg	N/A	-	N/A	-	N/A	-

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

RESULTS OF ANALYSES OF IMPING

Maxxam ID		G81230	G81236		G81239	
Sampling Date		6/9/2005	6/9/2005		6/9/2005	
	Units	**M8-FRONT HALF-RUN#3**	**M8-3% H2O2 BLANK SO2**	**DL**	**M8-BACK HALF-RUN#1 SO2**	**DL**
Sulphuric Acid Mist	mg	9.1	N/A	-	N/A	-
Sulphur dioxide	mg	N/A	0.48	0.36	95	1.3

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

RESULTS OF ANALYSES OF IMPING

Maxxam ID		G81240	G81241		
Sampling Date		6/9/2005	6/9/2005		
	Units	**M8-BACK HALF-RUN#2 SO2**	**M8-BACK HALF-RUN#3 SO2**	**DL**	**QC Batch**
Sulphuric Acid Mist	mg	N/A	N/A	-	778252
Sulphur dioxide	mg	340	310	7.1	768281

QC Batch = Quality Control Batch
Please check for attached comments

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

GENERAL COMMENTS

Possible lab contamination for Pb due to level found in processed blank.

Sample G81002-01: IMPVOL=125ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81006-01: IMPVOL=65ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81008-01: IMPVOL=425ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81009-01: IMPVOL=435ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81010-01: IMPVOL=425ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81094-01: IMPVOL=125ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81097-01: IMPVOL=150ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81099-01: IMPVOL=260ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81100-01: IMPVOL=265ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81101-01: IMPVOL=275ML
IMPCHARG=200ML
VOL ADJUST=2000ML

Sample G81183-01: sulphuric acid mist run by ion chromatography due to

Catalyst Air Management
Client Project #: EKPC
Project name: SPUNLOCK 3

Maxxam Job #: A557722
Report Date: 2005/07/13

GENERAL COMMENTS

interference which did not allow an endpoint to be visible during a titration.

Sample G81227-01: sulphuric acid mist run by ion chromatography due to interference which did not allow an endpoint to be visible during a titration.

Sample G81228-01: sulphuric acid mist run by ion chromatography due to interference which did not allow an endpoint to be visible during a titration.

Sample G81230-01: sulphuric acid mist run by ion chromatography due to interference which did not allow an endpoint to be visible during a titration.

Sample G81368-01: Post digestion duplicate and spike done for Pb and Be

Results relate only to the items tested.

Catalyst Air Management
Attention: Mike Taylor
Client Project #: EKPC
Project name: SPUNLOCK 3

Quality Assurance Report
Maxxam Job Number: GA557722

QA/QC Batch Num	Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
766374	M_N	MATRIX SPIKE (G81368)	Total Mercury-3A	7/6/2005	0.11, DL=0.01	106	ug	85 - 115
		MATRIX SPIKE DUP (G81368)	Total Mercury-3A	7/6/2005	0.11, DL=0.01	112	ug	85 - 115
		Spiked Blank	Total Mercury-3A	7/6/2005	0.11, DL=0.01	109	ug	90 - 110
		Spiked Blank DUP	Total Mercury-3A	7/6/2005	0.11, DL=0.01	109	ug	90 - 110
		Method Blank	Total Mercury-3A	7/6/2005	<0.01		ug	
		RPD	Total Mercury-3A	7/6/2005	NC		%	20
766380	M_N	MATRIX SPIKE (G81368)	Total Mercury-2B	7/6/2005	0.00, DL=0.62	103	ug	85 - 115
		MATRIX SPIKE DUP (G81368)	Total Mercury-2B	7/6/2005	0.00, DL=0.62	105	ug	85 - 115
		Spiked Blank	Total Mercury-2B	7/6/2005	0.11, DL=0.01	106	ug	90 - 110
		Spiked Blank DUP	Total Mercury-2B	7/6/2005	0.10, DL=0.01	102	ug	90 - 110
		Method Blank	Total Mercury-2B	7/6/2005	<0.01		ug	
		RPD	Total Mercury-2B	7/6/2005	NC		%	20
766677	A_S	MATRIX SPIKE (G81099)	Chlorine	6/24/2005	0, DL=100	103	ug	80 - 120
		MATRIX SPIKE DUP (G81099)	Chlorine	6/24/2005	0, DL=100	104	ug	80 - 120
		MATRIX SPIKE (G81099)	Fluorine	6/24/2005	0, DL=100	90	ug	80 - 120
		MATRIX SPIKE DUP (G81099)	Fluorine	6/24/2005	0, DL=100	90	ug	80 - 120
		Spiked Blank	Chlorine	6/24/2005	0, DL=100	102	ug	90 - 110
		Spiked Blank DUP	Chlorine	6/24/2005	0, DL=100	104	ug	90 - 110
		Spiked Blank	Fluorine	6/24/2005	0, DL=100	95	ug	90 - 110
		Spiked Blank DUP	Fluorine	6/24/2005	0, DL=100	96	ug	90 - 110
		Method Blank	Chlorine	6/24/2005	<100		ug	
		Method Blank DUP	Chlorine	6/24/2005	<100		ug	
		Method Blank	Fluorine	6/24/2005	<100		ug	
		Method Blank DUP	Fluorine	6/24/2005	<100		ug	
		RPD	Chlorine	6/24/2005	NC		%	20
			Fluorine	6/24/2005	NC		%	20
			Chlorine	6/24/2005	NC		%	20
			Fluorine	6/24/2005	NC		%	20
			Chlorine	6/24/2005	4.9		%	20
			Fluorine	6/24/2005	NC		%	20
			Chlorine	6/24/2005	0.4		%	20
			Fluorine	6/24/2005	NC		%	20
			Chlorine	6/24/2005	0.8		%	20
			Fluorine	6/24/2005	NC		%	20
768281	BAT	MATRIX SPIKE	Sulphur dioxide	6/28/2005	5.0, DL=0.29	100	mg	80 - 120
		Method Blank	Sulphur dioxide	6/28/2005	<2		mg	
		RPD	Sulphur dioxide	6/28/2005	0.2		%	20
769333	N_R	MATRIX SPIKE	Total Beryllium (Be)	6/30/2005	0.0, DL=0.1	104	ug	N/A
		MATRIX SPIKE DUP	Total Beryllium (Be)	6/30/2005	0.0, DL=0.1	104	ug	N/A
		MATRIX SPIKE	Total Lead (Pb)	6/30/2005	0.0, DL=0.2	98	ug	N/A
		MATRIX SPIKE DUP	Total Lead (Pb)	6/30/2005	0.0, DL=0.2	97	ug	N/A
		Spiked Blank	Total Beryllium (Be)	6/30/2005	53.5, DL=0.1	107	ug	85 - 115
		Spiked Blank DUP	Total Beryllium (Be)	6/30/2005	52.5, DL=0.1	105	ug	85 - 115
		Spiked Blank	Total Lead (Pb)	6/30/2005	50.5, DL=0.2	101	ug	85 - 115
		Spiked Blank DUP	Total Lead (Pb)	6/30/2005	50.0, DL=0.2	100	ug	85 - 115
		Method Blank	Total Beryllium (Be)	6/30/2005	<0.1		ug	

Catalyst Air Management
Attention: Mike Taylor
Client Project #: EKPC
Project name: SPUNLOCK 3

Quality Assurance Report
Maxxam Job Number: GA557722

QA/QC Batch Num	Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
		Method Blank DUP	Total Beryllium (Be)	6/30/2005	<0.1		ug	
		Method Blank	Total Lead (Pb)	6/30/2005	1.5	DL=0.2	ug	
		Method Blank DUP	Total Lead (Pb)	6/30/2005	1.5	DL=0.2	ug	
		RPD	Total Beryllium (Be)	6/30/2005	NC		%	20
			Total Lead (Pb)	6/30/2005	1.3		%	20
770520	M_N	MATRIX SPIKE (G81368)	Total Mercury-1B	6/30/2005	0.32, DL=0.03	105	ug	85 - 115
		MATRIX SPIKE DUP (G81368)	Total Mercury-1B	6/30/2005	0.31, DL=0.03	102	ug	85 - 115
		Spiked Blank	Total Mercury-1B	6/30/2005	0.31, DL=0.03	102	ug	90 - 110
		Spiked Blank DUP	Total Mercury-1B	6/30/2005	0.31, DL=0.03	103	ug	90 - 110
		Method Blank	Total Mercury-1B	6/30/2005	<0.03		ug	
		RPD	Total Mercury-1B	6/30/2005	NC		%	20
774522	M_N	MATRIX SPIKE (G81368)	Total Mercury - MnO4 - 1	7/7/2005	0.51, DL=0.05	102	ug	85 - 115
		MATRIX SPIKE DUP (G81368)	Total Mercury - MnO4 - 1	7/7/2005	0.51, DL=0.05	102	ug	85 - 115
		Spiked Blank	Total Mercury - MnO4 - 1	7/7/2005	0.52, DL=0.05	103	ug	90 - 110
		Spiked Blank DUP	Total Mercury - MnO4 - 1	7/7/2005	0.52, DL=0.05	103	ug	90 - 110
		Method Blank	Total Mercury - MnO4 - 1	7/7/2005	<0.05		ug	
		RPD	Total Mercury - MnO4 - 1	7/7/2005	NC		%	20
775459	M_N	MATRIX SPIKE (G81368)	Total Mercury-3C	7/11/2005	0.46, DL=0.05	92	ug	85 - 115
		MATRIX SPIKE DUP (G81368)	Total Mercury-3C	7/11/2005	0.49, DL=0.05	97	ug	85 - 115
		Spiked Blank	Total Mercury-3C	7/11/2005	0.51, DL=0.05	101	ug	90 - 110
		Spiked Blank DUP	Total Mercury-3C	7/11/2005	0.52, DL=0.05	104	ug	90 - 110
		Method Blank	Total Mercury-3C	7/11/2005	<0.05		ug	
		RPD	Total Mercury-3C	7/11/2005	0.4		%	20
776755	A_S	MATRIX SPIKE (G81008)	Hydrochloric Acid	7/11/2005	0, DL=100	105	ug	80 - 120
		MATRIX SPIKE DUP (G81008)	Hydrochloric Acid	7/11/2005	0, DL=100	104	ug	80 - 120
		MATRIX SPIKE (G81008)	Hydrofluoric Acid	7/11/2005	0, DL=100	102	ug	80 - 120
		MATRIX SPIKE DUP (G81008)	Hydrofluoric Acid	7/11/2005	0, DL=100	102	ug	80 - 120
		Spiked Blank	Hydrochloric Acid	7/11/2005	0, DL=100	100	ug	90 - 110
		Spiked Blank DUP	Hydrochloric Acid	7/11/2005	0, DL=100	100	ug	90 - 110
		Spiked Blank	Hydrofluoric Acid	7/11/2005	0, DL=100	98	ug	90 - 110
		Spiked Blank DUP	Hydrofluoric Acid	7/11/2005	0, DL=100	98	ug	90 - 110
		Method Blank	Hydrochloric Acid	7/11/2005	<100		ug	
		Method Blank DUP	Hydrochloric Acid	7/11/2005	<100		ug	
		Method Blank	Hydrofluoric Acid	7/11/2005	<100		ug	
		Method Blank DUP	Hydrofluoric Acid	7/11/2005	<100		ug	
		RPD	Hydrochloric Acid	7/11/2005	NC		%	20
			Hydrofluoric Acid	7/11/2005	NC		%	20
			Hydrochloric Acid	7/11/2005	NC		%	20
			Hydrofluoric Acid	7/11/2005	NC		%	20
			Hydrochloric Acid	7/11/2005	NC		%	20
			Hydrofluoric Acid	7/11/2005	NC		%	20
			Hydrochloric Acid	7/11/2005	NC		%	20
			Hydrofluoric Acid	7/11/2005	NC		%	20
			Hydrochloric Acid	7/11/2005	NC		%	20
			Hydrofluoric Acid	7/11/2005	NC		%	20
778252	BAT	MATRIX SPIKE (G81227)	Sulphuric Acid Mist	7/12/2005	5.1, DL=0.25	102	mg	80 - 120

Catalyst Air Management
Attention: Mike Taylor
Client Project #: EKPC
Project name: SPUNLOCK 3

Quality Assurance Report
Maxxam Job Number: GA557722

QA/QC Batch Num	Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
		Spiked Blank	Sulphuric Acid Mist	7/12/2005	4.9, DL=0.1	97	mg	90 - 110
		Method Blank	Sulphuric Acid Mist	7/12/2005	<0.1		mg	
		RPD	Sulphuric Acid Mist	7/12/2005	0.5		%	20

NC = Non-calculable
RPD = Relative Percent Difference
SPIKE = Fortified sample

METHOD 29 SUB[illegible]SSION STATUS

G81318 G81369

Client ID: Catalyst

PSC Sample #: G81368 G81376

M29 Container #	Receipt Confirmation (P/A)	Volume Mark (P/A)	Volume as Marked*** (Y/N)	Comments
Reagent Blank				
Portions for all Metals				
12 Filters (3 min.*): # of filters = 1	P/A			PPD
7 Acetone (Req. 100 ml)	P/A	P/A	Y/N	
8A 0.1 N Nitric Acid (Req. 300 ml**)	P/A	P/A	Y/N	500cc
9 Nitric/Peroxide (Req. 200 ml)	P/A	P/A	Y/N	500cc
Portions for Mercury only				
10 KMnO4/H2SO4 (Req. 100 ml)	P/A	P/A	Y/N	250cc
8B Water (Req. 100 ml)	P/A	P/A	Y/N	500cc
11 HCl (Req. 200 ml water + 25 ml 8N HCl)	P/A	P/A	Y/N	
Run # 1				
Portions for all Metals				
1 Filter	P/A			PPD
2 Acetone Rinse	P/A	P/A	Y/N	
3 Nitric Probe Rinse	P/A	P/A	Y/N	250cc
4 Nitric/Peroxide and Rinses	P/A	P/A	Y/N	1Lcc
Portions for Mercury only				
5A Impinger 4 and Rinses	P/A	P/A	Y/N	250cc
5B Permanganate and Rinses	P/A	P/A	Y/N	1Lcc
5C HCl Rinse	P/A	P/A	Y/N	250cc

M29 Container #	Receipt Confirmation (P/A)	Volume Mark (P/A)	Volume as Marked*** (Y/N)	Comments
Run # 2				
Portions for all Metals				
1 Filter	P/A			Same
2 Acetone Rinse	P/A	P/A	Y/N	
3 Nitric Probe Rinse	P/A	P/A	Y/N	
4 Nitric/Peroxide and Rinses	P/A	P/A	Y/N	
Portions for Mercury only				
5A Impinger 4 and Rinses	P/A	P/A	Y/N	
5B Permanganate and Rinses	P/A	P/A	Y/N	
5C HCl Rinse	P/A	P/A	Y/N	
Run # 3				
Portions for all Metals				
1 Filter	P/A			Same
2 Acetone Rinse	P/A	P/A	Y/N	
3 Nitric Probe Rinse	P/A	P/A	Y/N	
4 Nitric/Peroxide and Rinses	P/A	P/A	Y/N	
Portions for Mercury only				
5A Impinger 4 and Rinses	P/A	P/A	Y/N	
5B Permanganate and Rinses	P/A	P/A	Y/N	
5C HCl Rinse	P/A	P/A	Y/N	

* 6 filters requested; 2 for laboratory method blanks, 2 for ICAP blank spikes & 2 for low level (ICP-MS/GFAA) blank spikes

** 200 ml required if Hg is not requested: 100 ml for FH rinse, 100 ml for peroxide rinses and 100 ml for Imp 4 rinses.

*** Estimated to be within 5% of the marked volume.

P = Present, A = Absent, Y = Yes, N = No.

Inspected By: _____

CHAIN OF CUSTODY

PSC

ANALYTICAL SERVICES INC.
5555 North Service Road
Burlington, Ontario L7L 5H7

Toll Free: 1-800-668-0639
Tel: (905) 332-8788
Fax: (905) 332-9169

Page 1 of 4

CLIENT INFORMATION

Company Name: CATALYST Air Management
Project Manager: M. L. Taylor
Address: 2505 Byington - Solway Rd
Knoxville, TN 37931
Phone #: 865 531-0075 Fax #: 865 531-0750
Sampled by: M Taylor

ANALYSIS REQUESTED

PSC Use Only	Field Sample ID	# Bottles	Matrix	Date	Time	HCl HF Method 26A	Cl2 I F2 Method 26A			Method 8						Level of contamination (low, high, unknown)
	Rn 1 Imp 1/2	1		6-9-05		✓										
	Rn 2 Imp 1/2	1		"		✓										
	Rn 3 Imp 1/2	1		"		✓										
	Rn 1 Imp 3/4	1		"			✓									
	Rn 2 Imp 3/4	1		"			✓									
	Rn 3 Imp 3/4	1		"			✓									
	DI Blank	1		"		✓	✓									
	0.1N H_2SO_4 Blank	1		"		✓										
	0.1N NaOH Blank	1		"			✓									
	80% IPA Blank	1		6-9-05						✓						

TAT (Turnaround Time)

RUSH TAT MUST HAVE PRIOR APPROVAL

*some exceptions apply please contact Lab

- STD 10 Business Days ☐
- RUSH 5 Business Days ☐
- RUSH 2 Business Days ☐
- RUSH 1 Business Days ☐
- Other Business Days ____

PROJECT INFORMATION

Project #: EKPC
Site: Spurlock 3
PO#:
PSC Quote #:
PSC Project #:
PSC Contact:

SPECIAL DETECTION LIMITS

MISA ☐

SPECIAL REQUIREMENTS / REGULATIONS

REMARKS

initial imp volume 100 ml for M-26A
~.5g sodium thiosulfate in Imp 3/4 samples

Client Signature: [signature]
Affiliation:
Date/Time: 6-21-05

Received By: [signature]
Affiliation: Morgan Jones
Date/Time: 6/21/05 8:45 am.

Rec'd By:
Date/Time

WHITE - LAB / YELLOW - CLIENT

SEE OVER FOR COMPLETION & SAMPLING INSTRUCTIONS

CHAIN OF CUSTODY

ANALYTICAL SERVICES INC.
5555 North Service Road
Burlington, Ontario L7L 5H7

Toll Free: 1-800-668-0639
Tel: (905) 332-8788
Fax: (905) 332-9169

CLIENT INFORMATION

Company Name: CATALYST
Project Manager: Mike Taylor
Address: as 1
Phone #: Same Fax #:
Sampled by:

ANALYSIS REQUESTED

PSC Use Only	Field Sample ID	# Bottles	Matrix	Date	Time	Metals M-29	Method 8			Be, Pb, Hg						Level of contamination (low, high, unknown)
	DI Blank	1		6-8-05		✓										
	10% H_2SO_4 / 4% $KMnO_4$ Blank	1		"		✓										
	5% HNO_3 / 10% H_2O_2 Blank	1		"		✓										
144	Run 1 Front Half	1		6-9-05			✓									
	Run 1 Back Half	1		"			✓									
	Run 2 Front Half	1		"			✓									
	Run 2 Back Half	1		"			✓									
	Run 3 Front Half	1		"			✓									
	Run 3 Back Half	1		"			✓									
	3% H_2O_2 Blank	1		"			✓									

TAT (Turnaround Time)

RUSH TAT MUST HAVE PRIOR APPROVAL

*some exceptions apply please contact Lab

- STD 10 Business Days ☐
- RUSH 5 Business Days ☐
- RUSH 2 Business Days ☐
- RUSH 1 Business Days ☐
- Other Business Days ____

PROJECT INFORMATION

Project #: EKPC
Site: Spurlock 3
PO#:
PSC Quote #:
PSC Project #:
PSC Contact:

SPECIAL DETECTION LIMITS

MISA ☐

SPECIAL REQUIREMENTS / REGULATIONS

REMARKS

Metals Be, Pb, Hg

Client Signature:
Affiliation:
Date/Time: 6-21-05

Received By:
Affiliation: Mapcom
Date/Time: 6/21/05 8:45 pm

Rec'd By:
Date/Time

WHITE - LAB / YELLOW - CLIENT

SEE OVER FOR COMPLETION & SAMPLING INSTRUCTIONS

CHAIN OF CUSTODY

ANALYTICAL SERVICES INC.
5555 North Service Road
Burlington, Ontario L7L 5H7

Toll Free: 1-800-668-0639
Tel: (905) 332-8788
Fax: (905) 332-9169

CLIENT INFORMATION

Company Name: CATALYST
Project Manager: Mike Taylor
Address: SAME as 1
Phone #: Fax #:
Sampled by:

ANALYSIS REQUESTED

PSC Use Only	Field Sample ID	# Bottles	Matrix	Date	Time	Methods 1 29	Be, Pb, Hg									Level of contamination (low, high, unknown)
	Run 1 Filter C-1156	1		6-8-05		✓										
	Run 2 Filter C-1157	1		"		✓										
	Run 3 Filter C-1155	1		"		✓										
	Filter Blank C-1158	1		"		✓										
	Run 1 Probe Rinse	1		"		✓										
	Run 1 Imp 1/2	1		"		✓										
	Run 1 Imp 3	1		"		✓										
	Run 1 Imp 4/5	1		"		✓										
	Run 1 HCl Rinse	1		"		✓										
	Run 2 Probe Rinse	1		"		✓										

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TAT (Turnaround Time)

RUSH TAT MUST HAVE PRIOR APPROVAL

*some exceptions apply please contact Lab

- STD 10 Business Days ☐
- RUSH 5 Business Days ☐
- RUSH 2 Business Days ☐
- RUSH 1 Business Days ☐
- Other Business Days

PROJECT INFORMATION

Project #: EKPC
Site: Spurlock 3
PO#:
PSC Quote #:
PSC Project #:
PSC Contact:

SPECIAL DETECTION LIMITS

MISA ☐

SPECIAL REQUIREMENTS / REGULATIONS

REMARKS

Metals - Be, Pb, Hg

Client Signature:
Affiliation:
Date/Time: 6-21-05

Received By:
Affiliation: Maxxam Inc.
Date/Time: 6/21/05 8:45am

Rec'd By:
Date/Time

WHITE - LAB / YELLOW - CLIENT

SEE OVER FOR COMPLETION & SAMPLING INSTRUCTIONS

CHAIN OF CUSTODY

ANALYTICAL SERVICES INC.
5555 North Service Road
Burlington, Ontario L7L 5H7

Toll Free: 1-800-668-0639
Tel: (905) 332-8788
Fax: (905) 332-9169

CLIENT INFORMATION

Company Name: CATALYST
Project Manager: Mike Taylor
Address: Spun Co
Phone #: Fax #:
Sampled by:

ANALYSIS REQUESTED

PSC Use Only	Field Sample ID	# Bottles	Matrix	Date	Time	Metals M-29 Be, Pb, Hg									Level of contamination (low, high, unknown)
	Run 2 Imp 1/2	1		6-8-05		✓									
	Run 2 Imp 3	1		"		✓									
	Run 2 Imp 4/5	1		"		✓									
176	Run 2 HCl Rinse	1		"		✓									
	Run 3 Probe Rinse	1		"		✓									
	Run 3 Imp 1/2	1		"		✓									
	Run 3 Imp 3	1		"		✓									
	Run 3 Imp 4/5	1		"		✓									
	Run 3 HCl Rinse	1		"		✓									
	0.1 N HNO3 Blank	1		"		✓									

TAT (Turnaround Time)

RUSH TAT MUST HAVE PRIOR APPROVAL

*some exceptions apply please contact Lab

- STD 10 Business Days ☐
- RUSH 5 Business Days ☐
- RUSH 2 Business Days ☐
- RUSH 1 Business Days ☐
- Other Business Days

PROJECT INFORMATION

Project #: EKPC
Site: Spunlock 3
PO#:
PSC Quote #:
PSC Project #:
PSC Contact:

SPECIAL DETECTION LIMITS

MISA ☐

SPECIAL REQUIREMENTS / REGULATIONS

REMARKS

Metals - Be, Pb, Hg

Client Signature:
Affiliation:
Date/Time: 6-21-05

Received By:
Affiliation: Magnum Inc.
Date/Time: 6/21/05 8:45 pm

Rec'd By:
Date/Time

WHITE - LAB / YELLOW - CLIENT

SEE OVER FOR COMPLETION & SAMPLING INSTRUCTIONS

FedEx Express — *US Airbill*

FedEx Tracking Number 85[illegible]47351815

Form ID No. 0200

1A8513

1B8513

1C8513

1E8ST3

1 From

Date 6/22/05 [redacted]

Sender's Name Jim Jackson Phone (10 346 1649

Company Maxxam Analytics

Address 1334 State Rd

Dept./Floor/Suite/Room

City Coraopolis State PA ZIP 15036

2 Your Internal Billing Reference

3 To

Recipient's Name Mike Challes Phone [illegible]

Company Maxxam Analytics, Inc. Burlington

Recipient's Address "Held For Pick-up"

We cannot deliver to P.O. boxes or P.O. ZIP codes. Dept./Floor/Suite/Room

Address 299 Cayuga Road

To request a package be held at a specific FedEx location, print FedEx address here.

City Cheektowaga State NY ZIP 14225

FedEx 8163 9992 9454

FedEx Tracking Number for Customer

8518 4735 1815 MPS 8163 9992 9362

4a Express Package Service — *Packages up to 150 lbs.* * To most locations

- [x] FedEx Priority Overnight — Next business morning*
- [ ] FedEx Standard Overnight — Next business afternoon*
- [ ] FedEx First Overnight — Earliest next business morning delivery to select locations*
- [ ] FedEx 2Day — Second business day*
- [ ] FedEx Express Saver — Third business day*

FedEx Envelope rate not available. Minimum charge: One-pound rate

4b Express Freight Service — *Packages over 150 lbs.* ** To most locations

- [ ] FedEx 1Day Freight* — Next business day**
- [ ] FedEx 2Day Freight — Second business day**
- [ ] FedEx 3Day Freight — Third business day**

* Call for Confirmation:

5 Packaging — * Declared value limit $500

- [ ] FedEx Envelope*
- [ ] FedEx Pak* — Includes FedEx Small Pak, FedEx Large Pak, and FedEx Sturdy Pak
- [ ] FedEx Box
- [ ] FedEx Tube
- [x] Other

6 Special Handling — Include FedEx address in Section 3.

- [ ] SATURDAY Delivery — Available ONLY for FedEx Priority Overnight, FedEx 2Day, FedEx 1Day Freight, and FedEx 2Day Freight to select ZIP codes
- [ ] HOLD Weekday at FedEx Location — Not available for FedEx First Overnight
- [x] HOLD Saturday at FedEx Location — Available ONLY for FedEx Priority Overnight and FedEx 2Day to select locations

Does this shipment contain dangerous goods? One box must be checked.

- [x] No
- [ ] Yes — As per attached Shipper's Declaration
- [ ] Yes — Shipper's Declaration not required
- [ ] Dry Ice — Dry Ice, 9, UN 1845 ____ x ____ kg

Dangerous goods (including Dry Ice) cannot be shipped in FedEx packaging.

- [ ] Cargo Aircraft Only

7 Payment *Bill to:* Enter FedEx Acct. No. or Credit Card No. below.

- [ ] Sender — Acct. No. in Section 1 will be billed.
- [ ] Recipient
- [x] Third Party
- [ ] Credit Card
- [ ] Cash/Check

Obtain Recip. Acct. No. [ ]

[redacted]

Total Packages	Total Weight	Total Declared Value†	Total Charges
3	83 #	$ 500.00	Credit Card Auth.

†Our liability is limited to $100 unless you declare a higher value. See back for details.

8 Sign to Authorize Delivery Without a Signature

By signing you authorize us to deliver this shipment without obtaining a signature and agree to indemnify and hold us harmless from any resulting claims.

Questions? Visit our Web site at fedex.com

or call 1.800.GoFedEx 1.800.463.3339.

Rev. Date 11/03 • Part #158281 • ©1994–2003 FedEx • PRINTED IN U.S.A. MWIA 04

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********** -COMM. JOURNAL- ********** DATE JUL-14-2005 ***** TIME 09:32 ********

MODE = MEMORY TRANSMISSION START=JUL-14 09:29 END=JUL-14 09:32

FILE NO.=738

STN NO.	COMM.	ONE-TOUCH/ ABBR NO.	STATION NAME/TEL NO.	PAGES	DURATION
001	OK	☎	18655310750	019/019	00:01:54

-PSC ANALYTICAL SERVICES -

********** -PSC ANALYTICAL - ***** - 1 905 332 1511- *********

MaxXam Analytics Inc — *Driven by Service and Science*

Catalyst Air Management
2505 Byington-Solway Rd
Knoxville, TN
USA 37931

Attention: Mike Taylor

Report Date: 2005/07/13

Your Project #: EKPC
Site: SPUNLOCK 3

ANALYTICAL REPORT

MAXXAM JOB #: A557722
Received: 2005/06/23, 12:00

Sample Matrix: Filter
Samples Received: 4

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Mercury - Filter and Acetone Rinse (1)	4	2005/06/30	2005/06/30	SOP ING-111	EPA CFR PTM 29
Total Metals Analysis on Comb. Train (1)	4	2005/06/29	2005/06/30	ING 109	SW 846 602D

Sample Matrix: Impinger Solution
Samples Received: 22

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Halogens by IC in Impingers (1)	5	2005/06/24	2005/06/24	SOP ING 211	EPA CFR PTM 26A
Mercury - HCl Impinger Solution (1)	4	2005/07/11	2005/07/11	SOP ING-111	EPA CFR PTM 29
Mercury - HNO3 Rinse Solution (1)	4	2005/07/05	2005/07/06	SOP ING-111	EPA CFR PTM 29
Mercury - HNO3/H2O2 Impinger Solution (1)	4	2005/07/05	2005/07/06	SOP ING-111	EPA CFR PTM 29
Mercury - KMnO4/H2SO4 Impinger Solution (1)	4	2005/07/07	2005/07/07	SOP ING-111	EPA CFR PTM 29
Hydrogen Halides by IC (1)	5	2005/07/11	2005/07/11	SOP ING 211	EPA CFR PTM 26A
Sulphuric Acid Mist - Titration (1)	4	2005/07/12	2005/07/12	NCASI-EPA 8a	
Sulphur Dioxide in Impingers - Titration (1)	4	2005/06/27	2005/06/28	NCASI-EPA 8a	

(1) This test was performed by Maxxam Analytics Burlington

MAXXAM ANALYTICS INC.

MIKE CHALLIS, CET, B.Sc, C.Chem
Customer Service Manager, US Air Toxics

MDC/mdc
encl.

Total cover pages: 1

Particulate

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Spurlock Unit 3 6/16/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	140	110.4565	110.4567	0.0002

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 1.82E-06 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	150	108.4939	108.5008	0.0069	0.2490	0.2492	0.0002	0.0071	0.0002	0.0012	0.0069	6.9
Run 2	155	109.0396	109.0441	0.0045	0.2496	0.2507	0.0011	0.0056	0.0002	0.0012	0.0054	5.4
Run 3	155	109.4017	109.4073	0.0056	0.2488	0.2501	0.0013	0.0069	0.0002	0.0012	0.0067	6.7

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Spurlock Unit 3 - 20 % Opacity 8/17/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	125	104.4832	104.4832	0.0000

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 0.00E+00 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	125	103.5785	103.5936	0.0151	0.9929	1.0580	0.0651	0.0802	0.0000	0.0010	0.0802	80.2
Run 2	120	100.0909	100.1273	0.0364	1.0289	1.0758	0.0469	0.0833	0.0000	0.0009	0.0833	83.3
Run 3	125	103.1061	103.1414	0.0353	0.9982	1.0489	0.0507	0.0860	0.0000	0.0010	0.0860	86.0

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Spurlock Unit 3 - 8 % Opacity 8/17/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	125	104.4832	104.4832	0.0000

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 0.00E+00 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	130	108.6889	108.6936	0.0047	1.0227	1.0432	0.0205	0.0252	0.0000	0.0010	0.0252	25.2
Run 2	115	108.6308	108.6353	0.0045	0.9944	1.0183	0.0239	0.0284	0.0000	0.0009	0.0284	28.4
Run 3	115	103.5936	103.6089	0.0153	0.9942	1.0095	0.0153	0.0306	0.0000	0.0009	0.0306	30.6

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Spurlock Unit 3 - 6 % Opacity 8/18/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	125	104.4832	104.4832	0.0000

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 0.00E+00 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	115	108.6353	108.6421	0.0068	1.0069	1.0166	0.0097	0.0165	0.0000	0.0009	0.0165	16.5
Run 2	125	103.1414	103.1490	0.0076	1.0132	1.0221	0.0089	0.0165	0.0000	0.0010	0.0165	16.5
Run 3	120	100.1273	100.1301	0.0028	1.0046	1.0195	0.0149	0.0177	0.0000	0.0009	0.0177	17.7

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Spurlock Flyash Silo Baghouse 6/16/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	40	110.4565	110.4567	0.0002

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 6.37E-06 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	45	104.7858	104.7869	0.0011	0.1105	0.1125	0.0020	0.0031	0.0002	0.0004	0.0029	2.9
Run 2	45	96.4135	96.4153	0.0018	0.1105	0.1108	0.0003	0.0021	0.0002	0.0004	0.0019	1.9
Run 3	45	106.7692	106.7704	0.0012	0.1120	0.1123	0.0003	0.0015	0.0002	0.0004	0.0013	1.3

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Spurlock Bottom Ash Silo 6/14/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	40	110.4565	110.4567	0.0002

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 6.37E-06 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	45	106.4481	106.4500	0.0019	0.1104	0.1112	0.0008	0.0027	0.0002	0.0004	0.0025	2.5
Run 2	45	109.0655	109.0666	0.0011	0.1124	0.1140	0.0016	0.0027	0.0002	0.0004	0.0025	2.5
Run 3	45	107.8195	107.8212	0.0017	0.1113	0.1117	0.0004	0.0021	0.0002	0.0004	0.0019	1.9

CATALYST AIR MANAGEMENT, INC
ANALYTICAL SUMMARY
EKPC - Limestone Silo 6/15/2005

ACETONE BLANK

SAMPLE ID	VOLUME ml	BEAKER WEIGHT, g INITIAL	BEAKER WEIGHT, g FINAL	FINAL-INI g
Blank	45	110.4565	110.4567	0.0002

LOT NUMBER = 001793
DENSITY = 0.7849 g/ml

ACETONE BLANK = 5.66E-06 g/g

PARTICULATE WEIGHT

SAMPLE ID	ACETONE VOLUME ml	BEAKER WEIGHT g INITIAL	BEAKER WEIGHT g FINAL	FINAL-INI g	FILTER WEIGHT INITIAL	FINAL	FINAL-INI g	ACETONE PLUS FILTER g	ACETONE WASH BLANK g	MAXIMUM ALLOWABLE BLANK g	TOTAL g	mg
Run 1	45	107.8377	107.8389	0.0012	0.1114	0.1124	0.0010	0.0022	0.0002	0.0004	0.0020	2.0
Run 2	45	103.0762	103.0772	0.0010	0.1109	0.1122	0.0013	0.0023	0.0002	0.0004	0.0021	2.1
Run 3	45	107.8195	107.8205	0.0010	0.1125	0.1139	0.0014	0.0024	0.0002	0.0004	0.0022	2.2

APPENDIX 5
COAL ANALYSIS

Trace Metals Test

COAL SUMMARY
Trace Metals - Hg, Be and Pb

Run #	Fuel Type	Sample #	Hg Content Coal Samples (ng/g)	HHV (Btu/lb)	Coal hg Emission Rate (lb/MMBtu)	Outlet Hg Emission Rate (lb/MMBtu)	Actual Hg Removal (%)
1	Coal	1	115.0	11,888	9.67E-06	1.1E-06	88.63%
2	Coal	2	112.5	12,110	9.29E-06	8.7E-07	90.63%
3	Coal	3	127.5	12,349	1.03E-05	1.1E-06	89.35%
		Average:	**118.3**	**12,116**	**9.76E-06**	**1.0E-06**	**89.52%**

Run #	Fuel Type	Sample #	Be Content Coal Samples (ng/g)	HHV (Btu/lb)	Coal Be Emission Rate (lb/MMBtu)	Outlet Be Emission Rate (lb/MMBtu)	Actual Be Removal (%)
1	Coal	1	1975	11,888	1.66E-04	2.9E-08	99.98%
2	Coal	2	1675	12,110	1.38E-04	0.0E+00	100.00%
3	Coal	3	1775	12,349	1.44E-04	0.0E+00	100.00%
		Average:	**1808.3**	**12,116**	**1.49E-04**	**9.7E-09**	**99.99%**

Run #	Fuel Type	Sample #	Pb Content Coal Samples (ng/g)	HHV (Btu/lb)	Coal Pb Emission Rate (lb/MMBtu)	Outlet Pb Emission Rate (lb/MMBtu)	Actual Pb Removal (%)
1	Coal	1	6850	11,888	5.76E-04	4.0E-07	99.93%
2	Coal	2	8400	12,110	6.94E-04	2.8E-06	99.60%
3	Coal	3	5850	12,349	4.74E-04	1.8E-06	99.62%
		Average:	**7033.3**	**12,116**	**5.81E-04**	**1.7E-06**	**99.71%**

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-A SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259683

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.54	xxxxx
% Ash	14.78	15.48
% Volatile	36.64	38.38
% Fixed Carbon	44.04	46.14
	100.00	100.00
Btu/lb	11659	12214
% Sulfur	4.09	4.28
MAF Btu		14451

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.54	xxxxx
% Carbon	64.60	67.67
% Hydrogen	4.23	4.43
% Nitrogen	1.13	1.18
% Sulfur	4.09	4.28
% Ash	14.78	15.48
% Oxygen(diff)	6.63	6.96
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-A SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259683

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.12	ppm
Beryllium, Be	2.1	ppm
Lead, Pb	8.3	ppm
Fluorine, Fl	94.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Minerals Services Division
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Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-D SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259678

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	8.09	xxxxx
% Ash	16.87	18.35
% Volatile	34.47	37.50
% Fixed Carbon	40.57	44.15
	100.00	100.00
Btu/lb	10570	11500
% Sulfur	4.19	4.56
MAF Btu		14085

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	8.09	xxxxx
% Carbon	58.53	63.68
% Hydrogen	3.96	4.31
% Nitrogen	1.14	1.24
% Sulfur	4.19	4.56
% Ash	16.87	18.35
% Oxygen(diff)	7.22	7.86
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-D SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259678

PARAMETER	RESULTS	
Chlorine, Cl	0.01	%
Mercury, Hg	0.09	ppm
Beryllium, Be	2.4	ppm
Lead, Pb	9.1	ppm
Fluorine, Fl	137.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-B SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259679

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.24	xxxxx
% Ash	14.68	15.49
% Volatile	36.19	38.19
% Fixed Carbon	43.89	46.32
	100.00	100.00
Btu/lb	11264	11887
% Sulfur	3.85	4.06
MAF Btu		14066

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.24	xxxxx
% Carbon	62.60	66.06
% Hydrogen	4.24	4.47
% Nitrogen	1.13	1.19
% Sulfur	3.85	4.06
% Ash	14.68	15.49
% Oxygen(diff)	8.26	8.73
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-B SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259679

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.10	ppm
Beryllium, Be	1.7	ppm
Lead, Pb	5.2	ppm
Fluorine, Fl	118.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-C SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259680

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.14	xxxxx
% Ash	16.24	17.12
% Volatile	36.31	38.28
% Fixed Carbon	42.31	44.60
	100.00	100.00
Btu/lb	11337	11951
% Sulfur	4.32	4.55
MAF Btu		14420

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.14	xxxxx
% Carbon	63.08	66.50
% Hydrogen	4.18	4.41
% Nitrogen	1.12	1.18
% Sulfur	4.32	4.55
% Ash	16.24	17.12
% Oxygen(diff)	5.92	6.24
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-C SILO
RUN 1
9:45 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259680

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.15	ppm
Beryllium, Be	1.7	ppm
Lead, Pb	4.8	ppm
Fluorine, Fl	112.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-B SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259681

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.68	xxxxx
% Ash	14.55	15.26
% Volatile	37.23	39.06
% Fixed Carbon	43.54	45.68
	100.00	100.00
Btu/lb	11762	12339
% Sulfur	3.97	4.16
MAF Btu		14561

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.68	xxxxx
% Carbon	64.70	67.88
% Hydrogen	4.26	4.47
% Nitrogen	1.15	1.21
% Sulfur	3.97	4.16
% Ash	14.55	15.26
% Oxygen(diff)	6.69	7.02
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-B SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259681

PARAMETER	RESULTS	
Chlorine, Cl	0.04	%
Mercury, Hg	0.10	ppm
Beryllium, Be	1.5	ppm
Lead, Pb	5.6	ppm
Fluorine, Fl	94.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-C SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259682

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.57	xxxxx
% Ash	14.93	15.64
% Volatile	37.12	38.90
% Fixed Carbon	43.38	45.46
	100.00	100.00
Btu/lb	11649	12207
% Sulfur	4.28	4.49
MAF Btu		14470

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.57	xxxxx
% Carbon	64.32	67.40
% Hydrogen	4.26	4.46
% Nitrogen	1.13	1.18
% Sulfur	4.28	4.49
% Ash	14.93	15.64
% Oxygen(diff)	6.51	6.83
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-C SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259682

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.13	ppm
Beryllium, Be	1.8	ppm
Lead, Pb	7.8	ppm
Fluorine, Fl	105.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-D SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259676

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.03	xxxxx
% Ash	15.89	16.91
% Volatile	35.78	38.08
% Fixed Carbon	42.30	45.01
	100.00	100.00
Btu/lb	11004	11710
% Sulfur	4.29	4.57
MAF Btu		14093

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.03	xxxxx
% Carbon	61.34	65.28
% Hydrogen	4.05	4.31
% Nitrogen	1.22	1.30
% Sulfur	4.29	4.57
% Ash	15.89	16.91
% Oxygen(diff)	7.18	7.63
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-D SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259676

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Mercury, Hg	0.12	ppm
Beryllium, Be	1.9	ppm
Lead, Pb	10.4	ppm
Fluorine, Fl	100.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-A SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259677

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.73	xxxxx
% Ash	15.33	16.09
% Volatile	36.86	38.69
% Fixed Carbon	43.08	45.22
	100.00	100.00
Btu/lb	11609	12185
% Sulfur	4.16	4.37
MAF Btu		14522

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.73	xxxxx
% Carbon	64.09	67.27
% Hydrogen	4.27	4.48
% Nitrogen	1.19	1.25
% Sulfur	4.16	4.37
% Ash	15.33	16.09
% Oxygen(diff)	6.23	6.54
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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F-465

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-A SILO
RUN 2
1:00 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259677

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Mercury, Hg	0.10	ppm
Beryllium, Be	1.9	ppm
Lead, Pb	6.8	ppm
Fluorine, Fl	101.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Edward Pendleton
Middlesboro Laboratory

204

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-B SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259684

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.05	xxxxx
% Ash	15.89	16.56
% Volatile	36.94	38.50
% Fixed Carbon	43.12	44.94
	100.00	100.00
Btu/lb	11548	12035
% Sulfur	3.91	4.08
MAF Btu		14424

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.05	xxxxx
% Carbon	64.06	66.76
% Hydrogen	4.23	4.41
% Nitrogen	1.13	1.18
% Sulfur	3.91	4.08
% Ash	15.89	16.56
% Oxygen(diff)	6.73	7.01
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-B SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259684

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.15	ppm
Beryllium, Be	1.9	ppm
Lead, Pb	9.7	ppm
Fluorine, Fl	108.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-D SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259685

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.86	xxxxx
% Ash	14.58	15.32
% Volatile	36.95	38.84
% Fixed Carbon	43.61	45.84
	100.00	100.00
Btu/lb	11411	11994
% Sulfur	3.99	4.19
MAF Btu		14164

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.86	xxxxx
% Carbon	64.33	67.62
% Hydrogen	4.21	4.43
% Nitrogen	1.11	1.17
% Sulfur	3.99	4.19
% Ash	14.58	15.32
% Oxygen(diff)	6.92	7.27
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-D SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259685

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.12	ppm
Beryllium, Be	1.6	ppm
Lead, Pb	3.3	ppm
Fluorine, Fl	79.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-C SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259686

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.61	xxxxx
% Ash	15.21	16.11
% Volatile	36.20	38.35
% Fixed Carbon	42.98	45.54
	100.00	100.00
Btu/lb	11394	12071
% Sulfur	4.37	4.63
MAF Btu		14389

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.61	xxxxx
% Carbon	62.69	66.42
% Hydrogen	4.19	4.44
% Nitrogen	1.10	1.17
% Sulfur	4.37	4.63
% Ash	15.21	16.11
% Oxygen(diff)	6.83	7.23
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-C SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259686

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.10	ppm
Beryllium, Be	1.5	ppm
Lead, Pb	4.5	ppm
Fluorine, Fl	124.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-A SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis Report No. 49-259687

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.15	xxxxx
% Ash	14.17	14.94
% Volatile	36.24	38.21
% Fixed Carbon	44.44	46.85
	100.00	100.00
Btu/lb	11661	12294
% Sulfur	3.97	4.19
MAF Btu		14453

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.15	xxxxx
% Carbon	64.15	67.63
% Hydrogen	4.20	4.43
% Nitrogen	1.14	1.20
% Sulfur	3.97	4.19
% Ash	14.17	14.94
% Oxygen(diff)	7.22	7.61
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
3-A SILO
RUN 3
3:15 PM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 8, 2005

Date received June 15, 2005

Analysis report no. 49-259687

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Mercury, Hg	0.14	ppm
Beryllium, Be	1.7	ppm
Lead, Pb	5.9	ppm
Fluorine, Fl	117.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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HCl/HF Test

COAL SUMMARY
Cl/F

Run #	Fuel Type	HHV (Btu/lb)	Weight % Chlorine in Coal	Coal Cl Emission Rate (lb/mmBtu)	Outlet HCl Emission Rate (lb/mmBtu)
1	Coal	11,924	0.030	0.025	5.5E-05
2	Coal	11,937	0.032	0.027	5.7E-05
3	Coal	11,781	0.032	0.027	5.6E-05
		11,881	**0.031**	**0.026**	**5.6E-05**

Run #	Fuel Type		HHV (Btu/lb)	F Content Coal Samples (ppm)	Coal F Emission Rate (lb/mmBtu)	Outlet HF Emission Rate (lb/mmBtu)
1	Coal		11,924	126.75	94.1	5.5E-05
2	Coal		11,937	119.50	99.9	5.7E-05
3	Coal		11,781	112.25	105.0	5.6E-05
		Average:	**11,881**	**119.50**	**99.6**	**5.6E-05**

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
B SILO
RUN 1
HCL TEST
08:30

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259920

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	6.11	xxxxx
% Ash	15.41	16.41
% Volatile	36.21	38.57
% Fixed Carbon	42.27	45.02
	100.00	100.00
Btu/lb	11240	11971
% Sulfur	4.10	4.37
MAF Btu		14321

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	6.11	xxxxx
% Carbon	62.16	66.21
% Hydrogen	4.08	4.35
% Nitrogen	1.16	1.24
% Sulfur	4.10	4.37
% Ash	15.41	16.41
% Oxygen(diff)	6.98	7.42
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
B SILO
RUN 1
HCL TEST
08:30

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259920

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	131.0	ppm
Mercury, Hg	0.16	ppm
Lead, Pb	2.8	ppm
Beryllium, Be	1.8	pmm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

216 Middlesboro Laboratory

Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
D SILO
RUN 1
HCL TEST
08:30

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259919

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.60	xxxxx
% Ash	14.74	15.61
% Volatile	36.54	38.71
% Fixed Carbon	43.12	45.68
	100.00	100.00
Btu/lb	11319	11990
% Sulfur	3.96	4.19
MAF Btu		14208

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.60	xxxxx
% Carbon	63.18	66.93
% Hydrogen	4.19	4.44
% Nitrogen	1.29	1.37
% Sulfur	3.96	4.19
% Ash	14.74	15.61
% Oxygen(diff)	7.04	7.46
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

217 Middlesboro Laboratory

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
D SILO
RUN 1
HCL TEST
08:30

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259919

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	123.0	ppm
Mercury, Hg	0.16	ppm
Lead, Pb	7.8	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 1
HCL TEST
08:30

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259914

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.27	xxxxx
% Ash	15.63	16.50
% Volatile	36.43	38.46
% Fixed Carbon	42.67	45.04
	100.00	100.00
Btu/lb	11322	11952
% Sulfur	4.39	4.63
MAF Btu		14314

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.27	xxxxx
% Carbon	62.84	66.34
% Hydrogen	4.12	4.35
% Nitrogen	1.15	1.21
% Sulfur	4.39	4.63
% Ash	15.63	16.50
% Oxygen(diff)	6.60	6.97
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

219 Middlesboro Laboratory

Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 1
HCL TEST
08:30

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259914

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	109.0	ppm
Mercury, Hg	0.12	ppm
Lead, Pb	7.9	ppm
Beryllium, Be	2.3	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
C SILO
RUN 1
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259912

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.83	xxxxx
% Ash	17.07	17.94
% Volatile	36.62	38.48
% Fixed Carbon	41.48	43.58
	100.00	100.00
Btu/lb	11216	11785
% Sulfur	4.51	4.74
MAF Btu		14361

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.83	xxxxx
% Carbon	61.57	64.70
% Hydrogen	4.11	4.32
% Nitrogen	1.11	1.17
% Sulfur	4.51	4.74
% Ash	17.07	17.94
% Oxygen(diff)	6.80	7.13
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
C SILO
RUN 1
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259912

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	144.0	ppm
Mercury, Hg	0.17	ppm
Lead, Pb	8.0	ppm
Beryllium, Be	1.7	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT # 3
D SILO
RUN 2
10:00 A.M.
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259922

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.64	xxxxx
% Ash	15.77	16.71
% Volatile	36.56	38.75
% Fixed Carbon	42.03	44.54
	100.00	100.00
Btu/lb	11223	11894
% Sulfur	4.23	4.48
MAF Btu		14280

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.64	xxxxx
% Carbon	62.28	66.00
% Hydrogen	4.00	4.24
% Nitrogen	1.16	1.23
% Sulfur	4.23	4.48
% Ash	15.77	16.71
% Oxygen(diff)	6.92	7.34
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT # 3
D SILO
RUN 2
10:00 A.M.
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259922

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	97.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	9.6	ppm
Beryllium, Be	2.2	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Edward Hamilton

224

Middlesboro Laboratory
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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 2
HCL TEST
10:00 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259913

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.86	xxxxx
% Ash	15.08	16.02
% Volatile	36.28	38.54
% Fixed Carbon	42.78	45.44
	100.00	100.00
Btu/lb	11180	11876
% Sulfur	4.03	4.28
MAF Btu		14141

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.86	xxxxx
% Carbon	62.10	65.97
% Hydrogen	4.10	4.36
% Nitrogen	1.12	1.19
% Sulfur	4.03	4.28
% Ash	15.08	16.02
% Oxygen(diff)	7.71	8.18
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 2
HCL TEST
10:00 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259913

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	123.0	ppm
Mercury, Hg	0.10	ppm
Lead, Pb	9.5	ppm
Beryllium, Be	2.4	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
C SILO
RUN 2
HCL TEST
10:00 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259915

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.41	xxxxx
% Ash	16.01	17.11
% Volatile	35.87	38.33
% Fixed Carbon	41.71	44.56
	100.00	100.00
Btu/lb	11143	11906
% Sulfur	3.93	4.20
MAF Btu		14364

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.41	xxxxx
% Carbon	62.19	66.45
% Hydrogen	4.00	4.27
% Nitrogen	1.09	1.16
% Sulfur	3.93	4.20
% Ash	16.01	17.11
% Oxygen(diff)	6.37	6.81
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
C SILO
RUN 2
HCL TEST
10:00 AM

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259915

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	126.0	ppm
Mercury, Hg	0.17	ppm
Lead, Pb	8.3	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
B SILO
RUN 2
HCL TEST
10:00 A.M.

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259921

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.99	xxxxx
% Ash	15.02	15.81
% Volatile	36.46	38.37
% Fixed Carbon	43.53	45.82
	100.00	100.00
Btu/lb	11470	12072
% Sulfur	4.01	4.22
MAF Btu		14339

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.99	xxxxx
% Carbon	64.26	67.63
% Hydrogen	4.09	4.31
% Nitrogen	1.16	1.22
% Sulfur	4.01	4.22
% Ash	15.02	15.81
% Oxygen(diff)	6.47	6.81
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
B SILO
RUN 2
HCL TEST
10:00 A.M.

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259921

PARAMETER	RESULTS	
Chlorine, Cl	0.04	%
Fluorine, Fl	132.0	ppm
Mercury, Hg	0.14	ppm
Lead, Pb	6.0	ppm
Beryllium, Be	1.5	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
B SILO
RUN 3
HCL TEST
11:00

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259917

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.52	xxxxx
% Ash	15.66	16.57
% Volatile	35.98	38.08
% Fixed Carbon	42.84	45.35
	100.00	100.00
Btu/lb	10828	11461
% Sulfur	3.85	4.07
MAF Btu		13737

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.52	xxxxx
% Carbon	61.89	65.51
% Hydrogen	3.99	4.22
% Nitrogen	1.18	1.25
% Sulfur	3.85	4.07
% Ash	15.66	16.57
% Oxygen(diff)	7.91	8.38
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

231

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
B SILO
RUN 3
HCL TEST
11:00

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259917

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	116.0	ppm
Mercury, Hg	0.13	ppm
Lead, Pb	8.1	ppm
Beryllium, Be	2.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 3
HCL TEST
11:00

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259918

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.29	xxxxx
% Ash	15.53	16.40
% Volatile	36.02	38.03
% Fixed Carbon	43.16	45.57
	100.00	100.00
Btu/lb	11348	11982
% Sulfur	4.22	4.46
MAF Btu		14333

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.29	xxxxx
% Carbon	62.68	66.18
% Hydrogen	4.09	4.32
% Nitrogen	1.48	1.56
% Sulfur	4.22	4.46
% Ash	15.53	16.40
% Oxygen(diff)	6.71	7.08
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 3
HCL TEST
11:00

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259918

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	107.0	ppm
Mercury, Hg	0.18	ppm
Lead, Pb	8.6	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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Minerals Services Division
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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT # 3
C SILO
RUN 3
11:00
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259923

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.73	xxxxx
% Ash	16.00	16.97
% Volatile	36.59	38.81
% Fixed Carbon	41.68	44.22
	100.00	100.00
Btu/lb	11207	11888
% Sulfur	3.94	4.18
MAF Btu		14318

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.73	xxxxx
% Carbon	63.08	66.91
% Hydrogen	3.99	4.23
% Nitrogen	1.24	1.32
% Sulfur	3.94	4.18
% Ash	16.00	16.97
% Oxygen(diff)	6.02	6.39
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

Minerals Services Division
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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT # 3
C SILO
RUN 3
11:00
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259923

PARAMETER	RESULTS	
Chlorine, Cl	0.04	%
Fluorine, Fl	121.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	8.1	ppm
Beryllium, Be	1.8	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT # 3
D SILO
RUN 3
11:00
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259924

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.21	xxxxx
% Ash	16.47	17.38
% Volatile	36.48	38.49
% Fixed Carbon	41.84	44.13
	100.00	100.00
Btu/lb	11180	11794
% Sulfur	4.20	4.43
MAF Btu		14275

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.21	xxxxx
% Carbon	62.61	66.05
% Hydrogen	4.11	4.34
% Nitrogen	1.27	1.34
% Sulfur	4.20	4.43
% Ash	16.47	17.38
% Oxygen(diff)	6.13	6.46
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

237 Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT # 3
D SILO
RUN 3
11:00
HCL TEST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259924

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	105.0	ppm
Mercury, Hg	0.17	ppm
Lead, Pb	10.1	ppm
Beryllium, Be	2.2	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Edward Paulton

Middlesboro Laboratory

238

Acid Mist Test

COAL SUMMARY
S

Run #	Fuel Type	HHV (Btu/lb)	Weight % Sulfur in Coal	Coal S Emission Rate (lb/mmBtu)	Acid Mist Emission Rate (lb/mmBtu)
1	Coal	11,986	4.32	7.208	0.004
2	Coal	12,124	4.28	7.060	0.004
3	Coal	12,051	4.38	7.269	0.005
		12,054	**4.327**	**7.179**	**0.004**

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 1
ACID MIST
14:00

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259916

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.06	xxxxx
% Ash	16.19	17.05
% Volatile	36.08	38.00
% Fixed Carbon	42.67	44.95
	100.00	100.00
Btu/lb	11337	11941
% Sulfur	4.26	4.49
MAF Btu		14395

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.06	xxxxx
% Carbon	63.03	66.39
% Hydrogen	4.18	4.40
% Nitrogen	1.15	1.21
% Sulfur	4.26	4.49
% Ash	16.19	17.05
% Oxygen(diff)	6.13	6.46
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
GILBERT 3
A SILO
RUN 1
ACID MIST
14:00

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259916

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	138.0	ppm
Mercury, Hg	0.06	ppm
Lead, Pb	7.1	ppm
Beryllium, Be	1.8	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

242

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
RUN 1
14:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259826

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.11	xxxxx
% Ash	14.91	15.55
% Volatile	35.96	37.50
% Fixed Carbon	45.02	46.95
	100.00	100.00
Btu/lb	11673	12173
% Sulfur	4.02	4.19
MAF Btu		14414

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.11	xxxxx
% Carbon	64.42	67.18
% Hydrogen	4.23	4.41
% Nitrogen	1.16	1.21
% Sulfur	4.02	4.19
% Ash	14.91	15.55
% Oxygen(diff)	7.15	7.46
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 243

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
RUN 1
14:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259826

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	134.0	ppm
Mercury, Hg	0.17	ppm
Lead, Pb	7.1	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
RUN 1
14:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259827

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.66	xxxxx
% Ash	15.43	16.36
% Volatile	35.33	37.45
% Fixed Carbon	43.58	46.19
	100.00	100.00
Btu/lb	11219	11892
% Sulfur	4.11	4.36
MAF Btu		14218

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.66	xxxxx
% Carbon	62.71	66.47
% Hydrogen	4.00	4.24
% Nitrogen	1.12	1.19
% Sulfur	4.11	4.36
% Ash	15.43	16.36
% Oxygen(diff)	6.97	7.38
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
RUN 1
14:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259827

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	111.0	ppm
Mercury, Hg	0.20	ppm
Lead, Pb	7.7	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
RUN 1
14:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259828

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.24	xxxxx
% Ash	16.33	17.23
% Volatile	36.42	38.43
% Fixed Carbon	42.01	44.34
	100.00	100.00
Btu/lb	11314	11940
% Sulfur	4.05	4.27
MAF Btu		14426

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.24	xxxxx
% Carbon	62.85	66.33
% Hydrogen	4.02	4.24
% Nitrogen	1.13	1.19
% Sulfur	4.05	4.27
% Ash	16.33	17.23
% Oxygen(diff)	6.38	6.74
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

247

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
RUN 1
14:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259828

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	133.0	ppm
Mercury, Hg	0.16	ppm
Lead, Pb	7.4	ppm
Beryllium, Be	1.6	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

248 Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259822

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.71	xxxxx
% Ash	15.18	16.27
% Volatile	35.41	37.96
% Fixed Carbon	42.70	45.77
	100.00	100.00
Btu/lb	11315	12129
% Sulfur	4.09	4.38
MAF Btu		14486

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.71	xxxxx
% Carbon	62.48	66.97
% Hydrogen	4.07	4.36
% Nitrogen	1.11	1.19
% Sulfur	4.09	4.38
% Ash	15.18	16.27
% Oxygen(diff)	6.36	6.83
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259822

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	127.0	ppm
Mercury, Hg	0.13	ppm
Lead, Pb	11.2	ppm
Beryllium, Be	1.8	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Edward Pendleton

Middlesboro Laboratory

250

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259823

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.38	xxxxx
% Ash	14.00	14.95
% Volatile	36.03	38.49
% Fixed Carbon	43.59	46.56
	100.00	100.00
Btu/lb	11378	12153
% Sulfur	4.04	4.31
MAF Btu		14289

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.38	xxxxx
% Carbon	63.26	67.57
% Hydrogen	4.09	4.37
% Nitrogen	1.12	1.20
% Sulfur	4.04	4.31
% Ash	14.00	14.95
% Oxygen(diff)	7.11	7.60
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

251 Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259823

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	103.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	7.5	ppm
Beryllium, Be	2.2	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259831

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.89	xxxxx
% Ash	16.51	17.54
% Volatile	36.02	38.27
% Fixed Carbon	41.58	44.19
	100.00	100.00
Btu/lb	11261	11966
% Sulfur	4.36	4.63
MAF Btu		14511

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.89	xxxxx
% Carbon	62.67	66.59
% Hydrogen	3.95	4.20
% Nitrogen	1.10	1.17
% Sulfur	4.36	4.63
% Ash	16.51	17.54
% Oxygen(diff)	5.52	5.87
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

253 Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259831

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	137.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	7.0	ppm
Beryllium, Be	1.6	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

254 Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259832

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.29	xxxxx
% Ash	14.24	15.04
% Volatile	36.18	38.20
% Fixed Carbon	44.29	46.76
	100.00	100.00
Btu/lb	11599	12247
% Sulfur	3.81	4.02
MAF Btu		14415

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.29	xxxxx
% Carbon	64.24	67.83
% Hydrogen	4.21	4.44
% Nitrogen	1.14	1.20
% Sulfur	3.81	4.02
% Ash	14.24	15.04
% Oxygen(diff)	7.07	7.47
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

255 Middlesboro Laboratory

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
RUN 2
16:40
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259832

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	131.0	ppm
Mercury, Hg	0.14	ppm
Lead, Pb	8.1	ppm
Beryllium, Be	2.2	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

256 Middlesboro Laboratory

Minerals Services Division
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Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259824

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	6.48	xxxxx
% Ash	16.83	18.00
% Volatile	36.07	38.57
% Fixed Carbon	40.62	43.43
	100.00	100.00
Btu/lb	11025	11789
% Sulfur	4.33	4.63
MAF Btu		14377

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	6.48	xxxxx
% Carbon	61.23	65.47
% Hydrogen	4.00	4.28
% Nitrogen	1.09	1.17
% Sulfur	4.33	4.63
% Ash	16.83	18.00
% Oxygen(diff)	6.04	6.45
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

257 Middlesboro Laboratory

Minerals Services Division
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Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259824

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	150.0	ppm
Mercury, Hg	0.21	ppm
Lead, Pb	8.8	ppm
Beryllium, Be	1.8	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

258

Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259825

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.88	xxxxx
% Ash	14.54	15.29
% Volatile	36.25	38.11
% Fixed Carbon	44.33	46.60
	100.00	100.00
Btu/lb	11560	12153
% Sulfur	4.00	4.21
MAF Btu		14347

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.88	xxxxx
% Carbon	64.40	67.70
% Hydrogen	4.11	4.32
% Nitrogen	1.16	1.22
% Sulfur	4.00	4.21
% Ash	14.54	15.29
% Oxygen(diff)	6.91	7.26
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Edward Pulliam

Middlesboro Laboratory 259

Minerals Services Division
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Member of the SGS Group

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259825

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	111.0	ppm
Mercury, Hg	0.14	ppm
Lead, Pb	6.7	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259829

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.30	xxxxx
% Ash	14.97	15.98
% Volatile	36.26	38.70
% Fixed Carbon	42.47	45.32
	100.00	100.00
Btu/lb	11397	12163
% Sulfur	4.11	4.39
MAF Btu		14476

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	6.30	xxxxx
% Carbon	63.24	67.49
% Hydrogen	4.13	4.41
% Nitrogen	1.13	1.21
% Sulfur	4.11	4.39
% Ash	14.97	15.98
% Oxygen(diff)	6.12	6.52
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259829

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	108.0	ppm
Mercury, Hg	0.22	ppm
Lead, Pb	5.5	ppm
Beryllium, Be	2.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

262 Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis Report No. 49-259830

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.20	xxxxx
% Ash	15.08	15.91
% Volatile	35.67	37.63
% Fixed Carbon	44.05	46.46
	100.00	100.00
Btu/lb	11470	12099
% Sulfur	4.09	4.31
MAF Btu		14388

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.20	xxxxx
% Carbon	64.32	67.85
% Hydrogen	4.03	4.25
% Nitrogen	1.13	1.19
% Sulfur	4.09	4.31
% Ash	15.08	15.91
% Oxygen(diff)	6.15	6.49
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
RUN 3
19:00
ACID MIST

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 9, 2005

Date received June 15, 2005

Analysis report no. 49-259830

PARAMETER	RESULTS	
Chlorine, Cl	0.03	%
Fluorine, Fl	127.0	ppm
Mercury, Hg	0.14	ppm
Lead, Pb	6.6	ppm
Beryllium, Be	2.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

NOx/SO_2/CO/VOC Test

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259814

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.46	xxxxx
% Ash	18.38	19.44
% Volatile	36.52	38.63
% Fixed Carbon	39.64	41.93
	100.00	100.00
Btu/lb	11001	11636
% Sulfur	6.18	6.54
MAF Btu		14444

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.46	xxxxx
% Carbon	60.69	64.19
% Hydrogen	4.03	4.26
% Nitrogen	0.96	1.02
% Sulfur	6.18	6.54
% Ash	18.38	19.44
% Oxygen(diff)	4.30	4.55
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259814

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	136.0	ppm
Mercury, Hg	0.20	ppm
Lead, Pb	6.5	ppm
Beryllium, Be	1.6	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259813

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.95	xxxxx
% Ash	16.24	17.27
% Volatile	35.98	38.26
% Fixed Carbon	41.83	44.47
	100.00	100.00
Btu/lb	11199	11908
% Sulfur	5.17	5.50
MAF Btu		14394

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.95	xxxxx
% Carbon	61.70	65.60
% Hydrogen	4.16	4.42
% Nitrogen	0.94	1.00
% Sulfur	5.17	5.50
% Ash	16.24	17.27
% Oxygen(diff)	5.84	6.21
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 268

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259813

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	115.0	ppm
Mercury, Hg	0.13	ppm
Lead, Pb	5.9	ppm
Beryllium, Be	1.5	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Edward Pendleton

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259815

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.25	xxxxx
% Ash	16.14	17.03
% Volatile	36.50	38.52
% Fixed Carbon	42.11	44.45
	100.00	100.00
Btu/lb	11381	12012
% Sulfur	4.97	5.25
MAF Btu		14478

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.25	xxxxx
% Carbon	63.00	66.49
% Hydrogen	4.13	4.36
% Nitrogen	0.99	1.04
% Sulfur	4.97	5.25
% Ash	16.14	17.03
% Oxygen(diff)	5.52	5.83
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259815

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	158.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	5.7	ppm
Beryllium, Be	1.8	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Minerals Services Division
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Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259816

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.39	xxxxx
% Ash	16.49	17.43
% Volatile	36.07	38.13
% Fixed Carbon	42.05	44.44
	100.00	100.00
Btu/lb	11328	11973
% Sulfur	5.47	5.78
MAF Btu		14500

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.39	xxxxx
% Carbon	61.59	65.10
% Hydrogen	4.11	4.34
% Nitrogen	0.98	1.04
% Sulfur	5.47	5.78
% Ash	16.49	17.43
% Oxygen(diff)	5.97	6.31
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Minerals Services Division
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F-465

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
VCO TEST
RUN 1
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259816

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	131.0	ppm
Mercury, Hg	0.19	ppm
Lead, Pb	9.2	ppm
Beryllium, Be	1.8	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259820

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.23	xxxxx
% Ash	17.13	17.89
% Volatile	36.79	38.41
% Fixed Carbon	41.85	43.70
	100.00	100.00
Btu/lb	11383	11886
% Sulfur	5.82	6.08
MAF Btu		14476

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.23	xxxxx
% Carbon	62.63	65.40
% Hydrogen	4.06	4.24
% Nitrogen	1.01	1.05
% Sulfur	5.82	6.08
% Ash	17.13	17.89
% Oxygen(diff)	5.12	5.34
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
A SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259820

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	102.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	8.8	ppm
Beryllium, Be	1.7	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 275

SGS North America Inc. | Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259819

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.11	xxxxx
% Ash	16.80	17.70
% Volatile	36.25	38.20
% Fixed Carbon	41.84	44.10
	100.00	100.00
Btu/lb	11196	11799
% Sulfur	5.45	5.74
MAF Btu		14337

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.11	xxxxx
% Carbon	61.50	64.81
% Hydrogen	4.01	4.23
% Nitrogen	0.97	1.02
% Sulfur	5.45	5.74
% Ash	16.80	17.70
% Oxygen(diff)	6.16	6.50
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
B SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259819

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	113.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	9.0	ppm
Beryllium, Be	1.7	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 277

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Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259821

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.68	xxxxx
% Ash	16.57	17.38
% Volatile	36.79	38.60
% Fixed Carbon	41.96	44.02
	100.00	100.00
Btu/lb	11325	11881
% Sulfur	5.07	5.32
MAF Btu		14380

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.68	xxxxx
% Carbon	61.82	64.85
% Hydrogen	4.09	4.29
% Nitrogen	1.01	1.06
% Sulfur	5.07	5.32
% Ash	16.57	17.38
% Oxygen(diff)	6.76	7.10
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

F-465

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259821

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	118.0	ppm
Mercury, Hg	0.13	ppm
Lead, Pb	14.9	ppm
Beryllium, Be	1.9	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 279

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259818

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.72	xxxxx
% Ash	18.03	19.12
% Volatile	35.69	37.86
% Fixed Carbon	40.56	43.02
	100.00	100.00
Btu/lb	11049	11719
% Sulfur	4.80	5.09
MAF Btu		14489

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.72	xxxxx
% Carbon	60.46	64.13
% Hydrogen	4.04	4.29
% Nitrogen	0.99	1.05
% Sulfur	4.80	5.09
% Ash	18.03	19.12
% Oxygen(diff)	5.96	6.32
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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GENERAL CONDITIONS OF SERVICE ON REVERSE

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July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
D SILO
VOC TEST
RUN 2
296 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259818

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	120.0	ppm
Mercury, Hg	0.15	ppm
Lead, Pb	11.6	ppm
Beryllium, Be	1.9	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 281

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
VCO TEST
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259817

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.55	xxxxx
% Ash	15.91	16.85
% Volatile	36.56	38.71
% Fixed Carbon	41.98	44.44
	100.00	100.00
Btu/lb	11363	12031
% Sulfur	4.85	5.13
MAF Btu		14469

ULTIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.55	xxxxx
% Carbon	62.11	65.76
% Hydrogen	4.11	4.35
% Nitrogen	1.01	1.07
% Sulfur	4.85	5.13
% Ash	15.91	16.85
% Oxygen(diff)	6.46	6.84
	100.00	100.00

Respectfully submitted:
SGS NORTH AMERICA INC.

Middlesboro Laboratory

Minerals Services Division
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Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
C SILO
VCO TEST
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259817

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Fluorine, Fl	106.0	ppm
Mercury, Hg	0.11	ppm
Lead, Pb	8.2	ppm
Beryllium, Be	1.7	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

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Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
SPURLOCK
VCO TEST
B SILO
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259688

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.20	xxxxx
% Ash	17.86	18.64
% Volatile	37.35	38.99
% Fixed Carbon	40.59	42.37
	100.00	100.00
Btu/lb	11234	11727
% Sulfur	6.07	6.34
MAF Btu		14414

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.20	xxxxx
% Carbon	61.82	64.53
% Hydrogen	4.12	4.30
% Nitrogen	0.95	0.99
% Sulfur	6.07	6.34
% Ash	17.86	18.64
% Oxygen(diff)	4.98	5.20
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

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Middlesboro Laboratory

Minerals Services Division
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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
SPURLOCK
VCO TEST
B SILO
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259688

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Mercury, Hg	0.16	ppm
Beryllium, Be	1.7	ppm
Lead, Pb	7.4	ppm
Fluorine, Fl	71.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
SPURLOCK
VCO TEST
A SILO
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259689

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.20	xxxxx
% Ash	16.82	17.74
% Volatile	37.05	39.08
% Fixed Carbon	40.93	43.18
	100.00	100.00
Btu/lb	10992	11595
% Sulfur	5.39	5.69
MAF Btu		14096

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	5.20	xxxxx
% Carbon	61.36	64.73
% Hydrogen	4.12	4.35
% Nitrogen	0.98	1.03
% Sulfur	5.39	5.69
% Ash	16.82	17.74
% Oxygen(diff)	6.13	6.46
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
SPURLOCK
VCO TEST
A SILO
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259689

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Mercury, Hg	0.16	ppm
Beryllium, Be	1.8	ppm
Lead, Pb	7.9	ppm
Fluorine, Fl	144.0	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory

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Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

Member of the SGS Group

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
SPURLOCK
VCO TEST
D SILO
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis Report No. 49-259690

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.68	xxxxx
% Ash	16.44	17.25
% Volatile	37.46	39.30
% Fixed Carbon	41.42	43.45
	100.00	100.00
Btu/lb	11216	11767
% Sulfur	5.76	6.04
MAF Btu		14220

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	4.68	xxxxx
% Carbon	62.07	65.12
% Hydrogen	4.18	4.38
% Nitrogen	0.98	1.03
% Sulfur	5.76	6.04
% Ash	16.44	17.25
% Oxygen(diff)	5.89	6.18
	100.00	100.00

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 288

Minerals Services Division
Route 2, Box 162A, Middlesboro, KY 40965 t (606) 248-4205 f (606) 248-0044 www.us.sgs.com/minerals

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GENERAL CONDITIONS OF SERVICE ON REVERSE

SGS

July 7, 2005

EAST KENTUCKY POWER CO-OP
BOX 707
WINCHESTER KY 40391
GAIL HAGGARD

Sample identification by
EAST KENTUCKY POWER CO-OP

SAMPLE BROUGHT IN
SPURLOCK
VCO TEST
D SILO
RUN 3
293 MW

Kind of sample reported to us COAL

Sample taken at EAST KENTUCKY POWER CO-OP

Sample taken by EAST KENTUCKY POWER CO-OP

Date sampled June 13, 2005

Date received June 15, 2005

Analysis report no. 49-259690

PARAMETER	RESULTS	
Chlorine, Cl	0.02	%
Mercury, Hg	0.16	ppm
Beryllium, Be	1.9	ppm
Lead, Pb	8.4	ppm
Fluorine, Fl	116.1	ppm

Procedure: The sample was prepared according to ASTM, Part 05.05, Method D 3683. The sample was analyzed for trace elements by Inductively Coupled Plasma Emission Spectroscopy.

Results: Results are reported in part per million (ppm).

Respectfully submitted,
SGS NORTH AMERICA INC.

Middlesboro Laboratory 289

Minerals Services Division
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GENERAL CONDITIONS OF SERVICE ON REVERSE

Particulate Test

GILBERT TEST 08/17/05-08/18/05

SAMPLE ID	MOISTURE	ASH	SULFUR	ARBTU	ODBTU	MAF	ARVM	ARFC	FC/VM	#SO2
8 % FEEDER A 8/17/05	8.58	15.46	3.95	10867	11886	14305	34.08	41.88	1.23	7.09
8 % FEEDER B 8/17/05	7.37	18.71	4.97	10314	11135	13953	33.70	40.21	1.19	9.40
8 % FEEDER C 8/17/05	8.82	16.68	4.35	10515	11532	14115	33.47	41.02	1.23	8.07
8 % FEEDER D 8/17/05	7.55	17.44	4.46	10652	11522	14200	34.18	40.83	1.19	8.16
20 % FEEDER A 8/17/05	7.80	17.40	4.35	10597	11494	14167	33.53	41.27	1.23	8.00
20 % FEEDER B 8/17/05	7.48	17.78	4.61	10528	11379	14087	33.77	40.97	1.21	8.54
20 % FEEDER C 8/17/05	8.71	16.83	4.32	10493	11494	14091	33.37	41.09	1.23	8.03
20 % FEEDER D 8/17/05	7.93	17.27	4.64	10573	11483	14134	33.67	41.13	1.22	8.56
6 % FEEDER A 8/18/05	7.96	16.71	4.24	10728	11656	14241	33.86	41.47	1.22	7.71
6 % FEEDER B 8/18/05	7.17	18.13	4.89	10540	11354	14110	33.63	41.07	1.22	9.05
6 % FEEDER C 8/18/05	7.98	17.44	4.42	10618	11539	14237	33.87	40.71	1.20	8.12
6 % FEEDER D 8/18/05	8.03	16.32	4.09	10813	11757	14294	34.23	41.42	1.21	7.38

APPENDIX 6

REFERENCE METHOD QUALITY ASSURANCE

Calibration Gas Specification Sheets

Airgas Knox

Certificate of Analysis: EPA Protocol Gas Mixture

Airgas Specialty Gases
12722 South Wentworth Avenue
Chicago, IL 60628
www.airgas.com

Cylinder Number:	CC170818	Reference Number:	54-124031977-8
Cylinder Pressure:	1999.6 PSIG	Expiration Date:	3/21/2008
Certification Date:	3/21/2005	Laboratory:	ASG - Chicago - IL

Certified Concentrations

Component	Concentration	Accuracy	Analytical Principle	Procedure
CARBON DIOXIDE	9.850 %	+/- 1%	NDIR	G1
OXYGEN	12.47 %	+/- 1%	Paramagnetic	G1
NITROGEN	Balance			

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences.

Notes:

Do not use cylinder below 150 psig.

Approval Signature

Reference Standard Information

Type	Balance Gas	Component	Cyl.Number	Concentration
NTRM 100504		OXYGEN	SG9168314BAL	20.98 %
NTRM 040604		CARBON DIOXIDE	XC034319B	19.84 %

Analytical Results

1st Component CARBON DIOXIDE

1st Analysis Date: 03/21/2005

R 19.86	S 9.86	Z 0	Conc 9.860 %
S 9.85	Z 0	R 19.85	Conc 9.845 %
Z 0	R 19.85	S 9.85	Conc 9.845 %
			AVG: 9.850 %

2nd Component OXYGEN

1st Analysis Date: 03/21/2005

R 20.99	S 12.47	Z 0	Conc 12.46 %
S 12.47	Z 0	R 20.98	Conc 12.47 %
Z 0	R 20.99	S 12.48	Conc 12.47 %
			AVG: 12.47 %

BOC GASES Kx

Assay Laboratory
BOC GASES
600 Union Landing Road
Riverton,NJ 08077
(856) 829 7878

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Knoxville Gas&Gear
2300 SYCAMORE DR
KNOXVILLE, TN 379211773

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	CC27084
EXPIRATION DATE	:	22-Feb-2007
CERTIFICATION DATE	:	23-Feb-2004
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24005985
LOT NUMBER	:	598143

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
CARBON DIOXIDE	18.00 %	17.88 %	+/-1.00% NIST Traceable	02/23/04
OXYGEN	22.50 %	22.63 %	+/-1.00% NIST Traceable	02/23/04
NITROGEN	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
SRM 2745	9-B-32	CAL010373	15.69 +/- 0.06 % CARBON DIOXIDE	04/03/07
NTRM 82659X	03060219	XC024390B	22.60 +/- 0.10 % O2/N2	05/01/07

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Siemens 5E DD721	NonDispersive Infrared	01/30/04
Siemens 5E BN805	Paramagnetic	02/11/04

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A Delaware Corporation

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QA Approved Eric Schultz

Knox

Airgas.

Certificate of Analysis: EPA Protocol Gas Mixture

Cylinder Number: CC79007 Reference Number: 54-124001977-6
Cylinder Pressure: 1999.6 PSIG Expiration Date: 3/29/2008
Certification Date: 3/29/2005 Laboratory: ASG - Chicago - IL

Certified Concentrations

Component	Concentration	Accuracy	Analytical Principle	Procedure
CARBON MONOXIDE	30.43 PPM	+/- 1%	NDIR	G1
NITROGEN	Balance			

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences.

Notes:

Do not use cylinder below 150 psig.

Signature on file

Approval Signature

Reference Standard Information

Type	Balance Gas	Component	Cyl.Number	Concentration
NTRM 980602		CARBON MONOXIDE	XC0144218	49.69 PPM

Analytical Results

1st Component CARBON MONOXIDE

1st Analysis Date: 03/21/2005

R 49.6	S 30.9	Z 0	Conc 30.87 PPM
S 30.7	Z 0	R 49.7	Conc 30.67 PPM
Z 0	R 49.6	S 30.5	Conc 30.47 PPM
			AVG: 30.67 PPM

2nd Analysis Date: 03/29/2005

R 49.6	S 30.2	Z 0	Conc 30.19 PPM
S 30.2	Z 0	R 49.6	Conc 30.19 PPM
Z 0	R 49.6	S 30.2	Conc 30.19 PPM
			AVG: 30.19 PPM

BOC GASES

Assay Laboratory
BOC GASES
600 Union Landing Road
Riverton,NJ 08077
(609) 829 7878

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Reading Compressed Plant
732 TULPEHOCKEN STREET
READING, PA 196010000

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	CC29504
EXPIRATION DATE	:	13-Aug-2005
CERTIFICATION DATE	:	22-Aug-2002
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24006032
LOT NUMBER	:	517004

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
CARBON MONOXIDE	60.00 ppm	60.5 ppm	+/-1.00% NIST Traceable	08/14/02 & 08/22/02
ROGEN	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
SRM 1679C	3-H-30	CAL011734	97.60 +/- 0.50 ppm CARBON MONOXIDE	05/29/03

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Siemens Ultramat 6E-N9-782	NonDispersive Infrared	07/29/02

QA Approved

BOC GASES PA

Assay Laboratory
BOC GASES
600 Union Landing Road
Riverton,NJ 08077
(856) 829 7878

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Reading Gas&Gear
732 Tulpehocken Street
READING, PA 19601

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	XC025385B
EXPIRATION DATE	:	30-Sep-2006
CERTIFICATION DATE	:	07-Oct-2003
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24014814
LOT NUMBER	:	577636

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
CARBON MONOXIDE	90.00 ppm	89.0 ppm	+/-1.00% NIST Traceable	09/30/03 & 10/07/03
NITROGEN	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
NTRM 81679	98060824	CC97299	98.00 +/- 0.70 ppm CO/N2	06/01/07

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Siemens 6E N1-L9-0191	NonDispersive Infrared	09/17/03

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A Delaware Corporation

QA Approved

BOC GASES

Assay Laboratory
BOC GASES
600 Union Landing Road
Riverton,NJ 08077
(856) 829 7878

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Knoxville Gas&Gear
2300 SYCAMORE DR
KNOXVILLE, TN 379211773

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	XC035849B
EXPIRATION DATE	:	18-Feb-2006
CERTIFICATION DATE	:	26-Feb-2004
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24010783
LOT NUMBER	:	598144

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
NITRIC OXIDE	45.00 ppm	45.3 ppm	+/-1.00% NIST Traceable	02/18/04 & 02/25/04
TOTAL OXIDES OF NITROGEN		45.3 ppm		
ROGEN	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
NTRM 81684	03060412	XC019211B	98.80 +/- 0.80 ppm NO/N2	06/01/07

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 560 ADU9800406 NO/NO2	FTIR	02/05/04

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QA Approved C. Canalzello

BOC GASES

Assay Laboratory
BOC GASES
600 Union Landing Road
Riverton,NJ 08077
(856) 829 7878

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
CATALYST AIR MANAGEMENT
2505 BYINGTON-SOLWAY RD
KNOXVILLE, TN 379313854

CUSTOMER PO NO: REPLACEMENT CYLINE

Previous Certification Date(s):

CYLINDER NO : XC028101B
EXPIRATION DATE : 19-Oct-2005
CERTIFICATION DATE : 28-Oct-2003
CYLINDER PRESSURE : 2000 psig
PRODUCT ID NO : 24011490
LOT NUMBER : 581584

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
NITRIC OXIDE	90.00 ppm	88.4 ppm	+/-1.00% NIST Traceable	10/20/03 & 10/27/03
TOTAL OXIDES OF NITROGEN		88.4 ppm		
NITROGEN	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
NTRM 81684	03060404	XC019194B	98.80 +/- 0.80 ppm NO/N2	06/01/07

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 560 ADU9800406 NO/NO2	FTIR	10/09/03

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A Delaware Corporation

QA Approved C. Cardwell

Airgas Low Range L2

Airgas Specialty Gases
5480 Hamilton Boulevard
Theodore, AL 36582
251.653.2500 Fax: 251.653.2530
www.airgas.com

Certificate of Analysis: EPA Protocol Gas Mixture

Cylinder Number:	SG9147792	Reference Number:	47-124029174-9
Cylinder Pressure:	1999.6 PSIG	Expiration Date:	2/7/2007
Certification Date:	2/7/2005	Laboratory:	ASG - Mobile - AL

Certified Concentrations

Component	Concentration	Accuracy	Analytical Principle	Procedure
NITRIC OXIDE	63.00 PPM	+/- 1%	CHEMILLUM	G1
SULFUR DIOXIDE	79.35 PPM	+/- 1%	NDIR	G1
NITROGEN	Balance			

Total oxides of nitrogen 63.10 PPM

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences.

Notes:Airgas PO 111618441

Do not use cylinder below 150 psig.

Approval Signature Cindy Stines

Reference Standard Information

Type	Balance Gas	Component	Cyl.Number	Concentration
GMIS 0	NITROGEN	SULFUR DIOXIDE	ND-15721	103.8 PPM
GMIS 0	NITROGEN	NITRIC OXIDE	CC158829	95.0 PPM

Analytical Results

1st Component NITRIC OXIDE

1st Analysis Date: 01/31/2005

R 95.00	S 63.00	Z 0.000	Conc 63.00 PPM
S 63.00	Z 0.000	R 95.00	Conc 63.00 PPM
Z 0.000	R 95.00	S 63.00	Conc 63.00 PPM
			AVG: 63.00 PPM

2nd Analysis Date: 02/07/2005

R 95.00	S 63.00	Z 0.000	Conc 63.00 PPM
S 63.00	Z 0.000	R 95.00	Conc 63.00 PPM
Z 0.000	R 95.00	S 63.00	Conc 63.00 PPM
			AVG: 63.00 PPM

2nd Component SULFUR DIOXIDE

1st Analysis Date: 01/31/2005

R 104.0	S 79.50	Z 0.000	Conc 79.35 PPM
S 79.50	Z 0.000	R 104.0	Conc 79.35 PPM
Z 0.000	R 104.0	S 79.50	Conc 79.35 PPM
			AVG: 79.35 PPM

2nd Analysis Date: 02/07/2005

R 104.0	S 79.50	Z 0.000	Conc 79.35 PPM
S 79.50	Z 0.000	R 104.0	Conc 79.35 PPM
Z 0.000	R 104.0	S 79.50	Conc 79.35 PPM
			AVG: 79.35 PPM

04/18/2005 13:28 FAX 859 745 1143 Environmental Department → Catalyst 002

BOC GASES Kx

Assay Laboratory
BOC GASES
1075 CINCLARE DRIVE
PORT ALLEN,LA 70767
(225) 388 0900

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Knoxville Gas&Gear
2300 SYCAMORE DR
KNOXVILLE, TN 37921

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	XC025320B
EXPIRATION DATE	:	02-Jun-2006
CERTIFICATION DATE	:	02-Jun-2004
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24005240
LOT NUMBER	:	608890

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certifiec to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
SULFUR DIOXIDE	125.00 ppm	125 ppm	+/-1.00% NIST Traceable	05/24/04 & 06/01/04
NITROGEN	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
NTRM 81694	05249401	CC21066	91.10 +/- 1.00 ppm SO2/N2	07/14/01

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet/550/AD19603531	FTIR	05/05/04

QA Approved Cheryl Baker

BOC GASES PA

Assay Laboratory
BOC GASES
2009 Bellaire Avenue
Royal Oak,MI 48067
(248) 399 9150

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Reading Compressed Plant
732 TULPEHOCKEN STREET
READING, PA 196010000

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	CC107541
EXPIRATION DATE	:	02-Dec-2005
CERTIFICATION DATE	:	03-Dec-2002
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24066761
LOT NUMBER	:	533668

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
METHANE	3.00 ppm	2.92 ppm	+/-1.00% NIST Traceable	12/03/02
AIR	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
SRM 1659A	11-F-37	CLM09642	9.85 +/- 0.11 ppm METHANE	05/09/07

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Agilent 6890 US00040025	Gas Chromatography	12/03/02

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BOC GASES PA

Assay Laboratory
BOC GASES
2009 Bellaire Avenue
Royal Oak,MI 48067
(248) 399 9150

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Reading Compressed Plant
732 TULPEHOCKEN STREET
READING, PA 196010000

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	CC95344
EXPIRATION DATE	:	02-Dec-2005
CERTIFICATION DATE	:	03-Dec-2002
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24066662
LOT NUMBER	:	533669

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
METHANE	5.00 ppm	5.05 ppm	+/-1.00% NIST Traceable	12/03/02
AIR	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
SRM 1659A	11-F-37	CLM09642	9.85 +/- 0.11 ppm METHANE	05/09/07

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Agilent 6890 US00040025	Gas Chromatography	12/03/02

QA Approved

BOC GASES PA

Assay Laboratory
BOC GASES
2009 Bellaire Avenue
Royal Oak,MI 48067
(248) 399 9150

CERTIFICATE OF ANALYSIS
EPA Protocol Gas

CUSTOMER
Reading Compressed Plant
732 TULPEHOCKEN STREET
READING, PA 196010000

CUSTOMER PO NO:

Previous Certification Date(s):

CYLINDER NO	:	XC019516B
EXPIRATION DATE	:	02-Dec-2005
CERTIFICATION DATE	:	03-Dec-2002
CYLINDER PRESSURE	:	2000 psig
PRODUCT ID NO	:	24065033
LOT NUMBER	:	533666

ANALYTICAL INFORMATION

This calibration standard has been certified per the 1997 EPA Traceability Protocol, Document EPA-600/97/121, Using Procedure G1. All Values certified to be +/-1% NIST Traceable.

Do Not Use This Cylinder below 150 psig. i.e. 1.0 Megapascal

Analytical Results

Components	Requested Mixture	Certified Concentration	Analytical Uncertainty	Assay Dates
METHANE	9.00 ppm	8.94 ppm	+/-1.00% NIST Traceable	11/26/02
AIR	BALANCE GAS			

CALIBRATION STANDARDS USED IN ASSAY

Type	LOT ID	Cylinder No	Concentration	Expiration
NTRM 81659	99060404	XC014069B	9.10 +/- 0.12 ppm CH4/AIR	02/01/03

ANALYTICAL INSTRUMENTS USED IN ASSAY

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Agilent 6890 US00040025	Gas Chromatography	11/26/02

ANALYTICAL RESULTS VERIFIED ON 12/03/02 WITH 0-10PPM CH4 CURVE.

QA Approved

NOx Converter Efficiency Test

CATALYST AIR MANAGEMENT, INC.
AIR QUALITY TESTING SERVICES

ANALYZER:	TECO 10A
SERIAL #:	10A/R-45164-273
TIME:	1:32
DATE:	6/2/05
TEST:	NOx CONVERTER EFFICIENCY

DATE	TIME	NOx ppm
6/2/2005	1:32	252.09
6/2/2005	1:33	254.71
6/2/2005	1:34	257.03
6/2/2005	1:35	257.32
6/2/2005	1:36	254.65
6/2/2005	1:37	254.99
6/2/2005	1:38	254.78
6/2/2005	1:39	260.19
6/2/2005	1:40	258.39
6/2/2005	1:41	257.02
6/2/2005	1:42	253.6
6/2/2005	1:43	254.65
6/2/2005	1:44	254.89
6/2/2005	1:45	257.15
6/2/2005	1:46	256.85
6/2/2005	1:47	253.88
6/2/2005	1:48	258.63
6/2/2005	1:49	255.12
6/2/2005	1:50	254.96
6/2/2005	1:51	255.5
6/2/2005	1:52	254.79
6/2/2005	1:53	254.78
6/2/2005	1:54	255.82
6/2/2005	1:55	253.42
6/2/2005	1:56	252.68
6/2/2005	1:57	250.53
6/2/2005	1:58	254.17
6/2/2005	1:59	252.18
6/2/2005	2:00	255.06
6/2/2005	2:01	258.05
6/2/2005	2:02	257.45
		AVG
		255.33
		ppm

Highest Concentration:	260.19
Ending Concentration:	257.45
Drift:	1.05%

CALIBRATION GASES

NOx:	450.9
O2:	22.63

ANALYZER SCALE : 500 ppm

CATALYST AIR MANAGEMENT, INC.
AIR QUALITY TESTING SERVICES

ANALYZER: TECO 10A
SERIAL #: 10A/R-45164-273
TIME: 9:40
DATE: 7/5/05
TEST: NOx CONVERTER EFFICIENCY

DATE	TIME	NOx ppm
7/5/2005	9:40	87.68
7/5/2005	9:41	87.66
7/5/2005	9:42	87.84
7/5/2005	9:43	88.45
7/5/2005	9:44	88.51
7/5/2005	9:45	88.29
7/5/2005	9:46	87.96
7/5/2005	9:47	87.84
7/5/2005	9:48	87.65
7/5/2005	9:49	87.42
7/5/2005	9:50	87.06
7/5/2005	9:51	86.78
7/5/2005	9:52	86.36
7/5/2005	9:53	86.03
7/5/2005	9:54	85.58
7/5/2005	9:55	86.22
7/5/2005	9:56	86.78
7/5/2005	9:57	86.22
7/5/2005	9:58	85.82
7/5/2005	9:59	85.57
7/5/2005	10:00	85.57
7/5/2005	10:01	86.06
7/5/2005	10:02	86.08
7/5/2005	10:03	87.07
7/5/2005	10:04	87.05
7/5/2005	10:05	87.07
7/5/2005	10:06	87.08
7/5/2005	10:07	87.01
7/5/2005	10:08	87.01
7/5/2005	10:09	87.07
7/5/2005	10:10	87
		AVG
		86.96
		ppm

Highest Concentration:	88.51
Ending Concentration:	87.00
Drift:	1.71%

CALIBRATION GASES

NOx:	225.2
O2:	22.60

ANALYZER SCALE : 100 ppm

Isokinetic Sampling Equipment

Catalyst Air Management, Inc.
POST-TEST METER BOX CALIBRATION

METER BOX NUMBER:	020
DATE:	03/28/05
CALIBRATED BY:	Nicely
BENCH METER CALIBRATION FACTOR:	1.0000

Orifice Manometer Setting (Δ H) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Outlet (T_{do}) °F	Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	ΔH@i	Q_m	K_m
0.50	571.415	**6.521**	518.255	**6.609**	66.8	71.0	68.5	69.8	29.50	15.00	**0.99**	**1.48**	0.440	0.791
	577.936		524.864											
1.00	565.161	**5.975**	511.802	**6.057**	67.2	71.5	68.0	69.8	29.50	10.00	**0.99**	**1.57**	0.604	0.768
	571.136		517.859											
2.00	556.159	**8.619**	502.728	**8.687**	67.2	71.0	68.5	69.8	29.50	10.17	**0.99**	**1.57**	0.852	0.767
	564.778		511.415											
3.00	545.566	**10.226**	492.164	**10.194**	67.0	73.0	67.2	70.1	29.50	10.00	**1.00**	**1.66**	1.014	0.746
	555.792		502.358											
4.00	533.521	**11.744**	480.313	**11.547**	67.3	70.2	67.0	68.6	29.50	10.00	**1.01**	**1.72**	1.151	0.733
	545.265		491.860											
										Average:	**1.00**	**1.60**		

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

$$\Delta H@i = \frac{0.9244}{K_m^{\,2}}$$

$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(Time)(T_{do} + 460)}$$

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Catalyst Air Management, Inc.

POST-TEST METER BOX CALIBRATION

METER BOX NUMBER:	020		
DATE:	06/10/05		
CALIBRATED BY:	Love	PRETEST Y_i:	1.00
		POST-TEST Y_i:	1.04
BENCH METER CALIBRATION FACTOR:	1.000	DIFFERENCE, %	4.53

Orifice Manometer Setting (ΔH) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Dry Gas Meter Outlet (T_{do}) °F	Dry Gas Meter Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	ΔH@i	Q_m	K_m
2.50	192.438	**9.379**	90.341	**9.086**	72.0	79.0	76.6	77.8	30.10	10.00	**1.04**	**1.73**	0.907	0.731
	201.817		99.427											
2.50	201.817	**9.347**	99.427	**9.037**	72.0	81.5	77.3	79.4	30.10	10.00	**1.04**	**1.76**	0.900	0.726
	211.164		108.464											
2.50	211.164	**9.405**	108.464	**9.085**	72.6	84.2	78.2	81.2	30.10	10.00	**1.05**	**1.75**	0.903	0.728
	220.569		117.549											

Average: **1.04** **1.74**

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

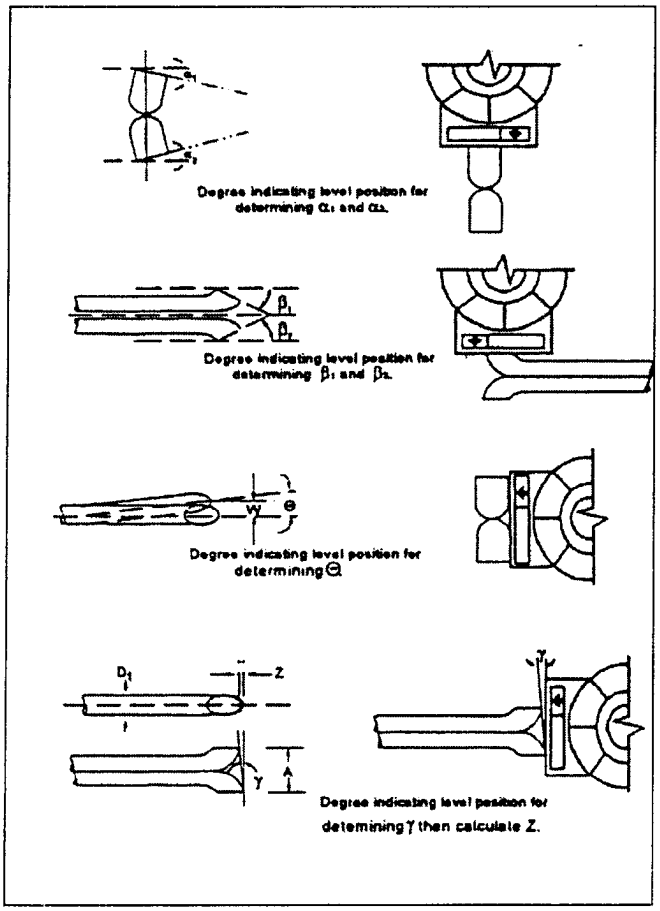
$$\Delta H@i = \frac{0.9244}{K_m^{\,2}}$$

$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(Time)(T_{do} + 460)}$$

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

"S" TYPE PITOT TUBE CALIBRATION – INSPECTION



ATTRIBUTE

Level and Perpendicular?	yes
Obstructed?	no
Damaged?	no
α_1 (-10° ≤ α_1 ≤ +10°)	2.0
α_2 (-10° ≤ α_2 ≤ +10°)	2.0
β_1 (-5° ≤ β_1 ≤ +5°)	0
β_2 (-5° ≤ β_2 ≤ +5°)	0
γ	2.0
θ	2.0
Z = A tan γ (≤ 0.125")	0.031
W = A tan θ (≤ 0.0.03125")	0.031
D_1 (3/16" ≤ D_1 ≤ 3/8")	0.375
A	0.875
$A/2D_1$ (1.05 ≤ P_A/D_1 ≤ 1.5)	1.17

QA / QC Check
Completeness ✓ Legibility ✓ Accuracy ✓ Specifications ✓ Reasonableness ✓

Certification:
I certify that the Type "S" pitot tube / probe. ID# CAM 107 meets or exceeds all specifications criteria and or applicable design features and is hereby assigned a pitot tube calibration factor of C_p of 0.84

Certified By: Hueden Dove 6/4/05 **Team Leader** [signature] 6/5/05
Personnel (Signature / Date Team Leader (Signature / Date

CATALYST AIR MANAGEMENT, INC

Barometer Calibration Check
EKPC

DATE: 6/3/2005
CALIBRATED BY: Taylor

Hg in glass Barometer (in Hg)	30.00
Field Barometer (in Hg)	29.98
Difference	-0.02

CATALYST AIR MANAGEMENT, INC.

NOZZLE CALIBRATION SHEET

Client: EKPC
Job No: 158-052

Nozzle No. 52 GLASS

1ST	2ND	3RD	AVG
0.217	0.217	0.217	0.217

Nozzle No. 55 GLASS

1ST	2ND	3RD	AVG
0.217	0.217	0.217	0.217

Nozzle No. 58 GLASS

1ST	2ND	3RD	AVG
0.217	0.217	0.217	0.217

Nozzle No. _____

1ST	2ND	3RD	AVG

Nozzle No. _____

1ST	2ND	3RD	AVG

Nozzle No. _____

1ST	2ND	3RD	AVG

Calibrated By: MJ
Date: 6-6-05

CATALYST AIR MANAGEMENT, INC

K-TYPE THERMOCOUPLE CALIBRATION

Post test Calibration Check
EKPC

DATE: 6/10/2005
CALIBRATED BY: Love

AVG STACK TEMPERATURE: 167

Thermocouple No;	**CAM 5**
Std Therometer	171
Thermocouple	170
Difference	1

Catalyst Air Management, Inc.

METER BOX NUMBER: 010
DATE: 02/08/05
CALIBRATED BY: Derrera

BENCH METER CALIBRATION FACTOR: 1.000

Orifice Manometer Setting (Δ H) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Outlet (T_{do}) °F	Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	ΔH@i	Q_m	K_m
0.50	305.050	**4.972**	267.036	**5.050**	66.0	74.0	74.0	74.0	30.01	11.45	**1.00**	**1.46**	0.441	0.796
	310.022		272.086											
1.00	310.022	**4.988**	272.086	**5.039**	67.0	76.0	76.0	76.0	30.01	8.05	**1.00**	**1.45**	0.626	0.798
	315.010		277.125											
2.00	315.280	**5.070**	277.406	**5.076**	67.0	76.0	76.0	76.0	30.01	6.10	**1.01**	**1.64**	0.832	0.750
	320.350		282.482											
3.00	320.350	**5.048**	282.482	**5.048**	67.0	76.0	76.0	76.0	30.01	5.00	**1.01**	**1.68**	1.010	0.743
	325.398		287.530											
4.00	299.595	**5.055**	261.586	**5.045**	66.0	72.0	72.0	72.0	30.01	4.12	**1.00**	**1.51**	1.225	0.783
	304.650		266.631											

Average: **1.01** **1.55**

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

$$\Delta H@i = \frac{0.9244}{K_m^{\ 2}}$$

$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(Time)(T_{do} + 460)}$$

Catalyst Air Management, Inc.

POST-TEST METER BOX CALIBRATION

METER BOX NUMBER:	010		
DATE:	08/22/05		
CALIBRATED BY:	Love	PRETEST Y_i:	1.01
		POST-TEST Y_i:	0.99
BENCH METER CALIBRATION FACTOR:	1.000	DIFFERENCE, %	-1.67

Orifice Manometer Setting (Δ H) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Outlet (T_{do}) °F	Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	ΔH@i	Q_m	K_m
1.20	687.685	**6.078**	389.033	**6.127**	79.8	80.6	80.0	80.3	30.00	10.00	**0.99**	**1.84**	0.612	0.710
	693.763		395.160											
1.20	693.763	**6.121**	395.160	**6.182**	82.0	82.2	80.0	81.1	30.00	10.00	**0.99**	**1.81**	0.617	0.715
	699.884		401.342											
1.20	699.884	**6.085**	401.342	**6.142**	82.0	84.2	82.2	83.2	30.00	10.50	**0.99**	**2.03**	0.584	0.675
	705.969		407.484											

Average: **0.99** **1.89**

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

$$\Delta H@i = \frac{0.9244}{K_m^{\,2}}$$

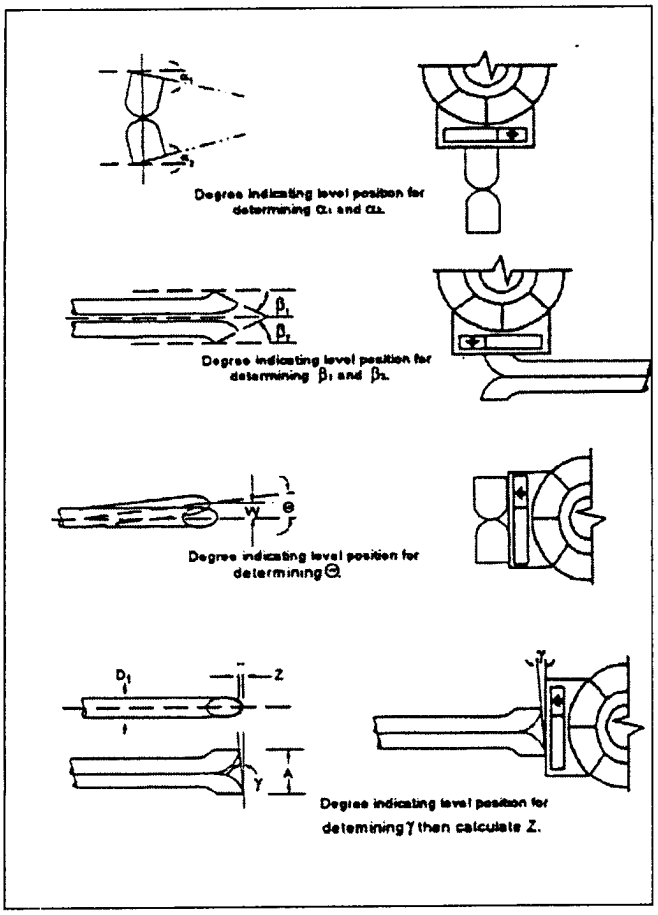
$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(Time)(T_{do} + 460)}$$

316

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

"S" TYPE PITOT TUBE CALIBRATION – INSPECTION



ATTRIBUTE

Level and Perpendicular?	yes
Obstructed?	no
Damaged?	no
α_1 (-10° ≤ α_1 ≤ +10°)	1.0
α_2 (-10° ≤ α_2 ≤ +10°)	2.0
β_1 (-5° ≤ β_1 ≤ +5°)	0
β_2 (-5° ≤ β_2 ≤ +5°)	0
γ	2.0
θ	1.0
Z = A tan γ (≤ 0.125")	0.034
W = A tan θ (≤ 0.0.03125")	0.017
D_1 (3/16" ≤ D_1 ≤ 3/8")	0.370
A	0.985
$A/2D_1$ (1.05 ≤ P_A/D_1 ≤ 1.5)	1.33

QA / QC Check
Completeness ✓ Legibility ✓ Accuracy ✓ Specifications ✓ Reasonableness ✓

Certification:
I certify that the Type "S" pitot tube / probe. ID# CAM 7 meets or exceeds all specifications criteria and or applicable design features and is hereby assigned a pitot tube calibration factor of C_p of 0.84

Certified By: Hueden Jose 8/12/05 **Team Leader** [signature] 8/12/05
Personnel (Signature / Date — Team Leader (Signature / Date

CATALYST AIR MANAGEMENT, INC

Barometer Calibration Check
EKPC

DATE: 8/12/2005
CALIBRATED BY: Love

Hg in glass Barometer (in Hg)	30.01
Field Barometer (in Hg)	29.98
Difference	-0.03

CATALYST AIR MANAGEMENT, INC.

NOZZLE CALIBRATION SHEET

Client: EKPC
Job No: 158-052

Nozzle No. 04

1ST	2ND	3RD	AVG
0.189	0.191	0.190	0.190

Nozzle No. 41

1ST	2ND	3RD	AVG
0.190	0.190	0.190	0.190

Nozzle No. 102

1ST	2ND	3RD	AVG
0.185	0.185	0.185	0.185

Nozzle No. _____

1ST	2ND	3RD	AVG

Nozzle No. _____

1ST	2ND	3RD	AVG

Nozzle No. _____

1ST	2ND	3RD	AVG

Calibrated By: M Tyler
Date: 8-16-05

CATALYST AIR MANAGEMENT, INC

K-TYPE THERMOCOUPLE CALIBRATION

Post test Calibration Check
EKPC

DATE: 8/22/2005
CALIBRATED BY: Love

AVG STACK TEMPERATURE: 174

Thermocouple No;	**CAM 7**
Std Therometer	175
Thermocouple	175
Difference	0

Catalyst Air Management, Inc.

METER BOX NUMBER: **070**
DATE: 03/28/05
CALIBRATED BY: Nicely

BENCH METER CALIBRATION FACTOR: 1.000

Orifice Manometer Setting (Δ H) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Outlet (T_{do}) °F	Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	ΔH@i	Q_m	K_m
0.50	664.468	**7.943**	286.658	**8.122**	71.0	74.0	74.0	74.0	29.50	19.38	**0.98**	**1.64**	0.419	0.750
	672.411		294.780											
1.00	657.151	**5.930**	280.616	**5.983**	71.0	74.0	74.0	74.0	29.50	10.10	**0.99**	**1.64**	0.592	0.750
	663.081		286.599											
2.00	648.769	**8.137**	272.009	**8.365**	70.5	72.0	72.0	72.0	29.50	10.00	**0.97**	**1.64**	0.837	0.750
	656.906		280.374											
3.00	638.410	**10.119**	261.487	**10.287**	70.0	70.7	70.7	70.7	29.50	10.00	**0.98**	**1.63**	1.029	0.754
	648.529		271.774											
4.00	625.915	**11.633**	248.481	**11.810**	68.7	69.7	69.7	69.7	29.50	10.00	**0.98**	**1.64**	1.181	0.750
	637.548		260.291											

Average: **0.98** **1.64**

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

$$\Delta H@i = \frac{0.9244}{K_m^{\ 2}}$$

$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(Time)(T_{do} + 460)}$$

Catalyst Air Management, Inc.

POST-TEST METER BOX CALIBRATION

METER BOX NUMBER:	070		
DATE:	08/12/05		
CALIBRATED BY:	Nicely	PRETEST Y_i:	0.98
		POST-TEST Y_i:	1.01
BENCH METER CALIBRATION FACTOR:	1.000	DIFFERENCE, %	2.72

Orifice Manometer Setting (ΔH) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Outlet (T_{do}) °F	Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	$\Delta H@i$	Q_m	K_m
1.40	659.602	**7.166**	458.473	**7.077**	72.2	73.0	72.0	72.5	30.10	10.00	**1.01**	**1.58**	0.707	0.765
	666.768		465.550											
1.40	666.768	**8.061**	465.550	**8.006**	72.0	73.6	73.6	73.6	30.10	11.40	**1.01**	**1.60**	0.702	0.759
	674.829		473.556											
1.40	674.829	**7.045**	473.556	**7.008**	72.2	74.3	73.5	73.9	30.10	10.00	**1.01**	**1.61**	0.700	0.757
	681.874		480.564											
										Average:	**1.01**	**1.60**		

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

$$\Delta H@i = \frac{0.9244}{K_m^{\,2}}$$

$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(Time)(T_{do} + 460)}$$

Catalyst Air Management, Inc.

METER BOX NUMBER: **030**
DATE: 03/28/05
CALIBRATED BY: Nicely

BENCH METER CALIBRATION FACTOR: 1.000

Orifice Manometer Setting (Δ H) In. H_2O	Standard Test Meter Start: End:	(V_w) ft^3	Dry Gas Meter Start: End:	(V_d) ft^3	Standard Test Meter (T_w) °F	Dry Gas Meter Inlet (T_{di}) °F	Outlet (T_{do}) °F	Average (T_d) °F	Barometric Pressure (P_b) in. of Hg	Time (Time) min.	Y_i	ΔH@i	Q_m	K_m
0.50	618.683	**5.997**	826.168	**6.068**	64.0	71.3	65.3	68.3	29.50	14.30	**1.00**	**1.59**	0.422	0.761
	624.680		832.236											
1.00	612.549	**5.926**	819.975	**5.966**	64.0	81.8	66.0	73.9	29.50	10.00	**1.01**	**1.65**	0.588	0.750
	618.475		825.941											
2.00	602.973	**8.988**	810.359	**9.011**	65.0	72.5	65.3	68.9	29.50	11.00	**1.00**	**1.71**	0.814	0.734
	611.961		819.370											
3.00	592.040	**10.540**	799.496	**10.478**	64.2	69.8	64.6	67.2	29.50	10.30	**1.00**	**1.66**	1.012	0.746
	602.580		809.974											
4.00	579.898	**11.583**	787.527	**11.405**	64.0	66.6	63.6	65.1	29.50	10.00	**1.01**	**1.75**	1.137	0.727
	591.481		798.932											

Average: **1.00** **1.67**

FORMULAS

$$Y_i = \frac{(V_w)(P_b)(T_d + 460)}{(V_d)\left(P_b + \frac{H}{13.6}\right)(T_w + 460)}$$

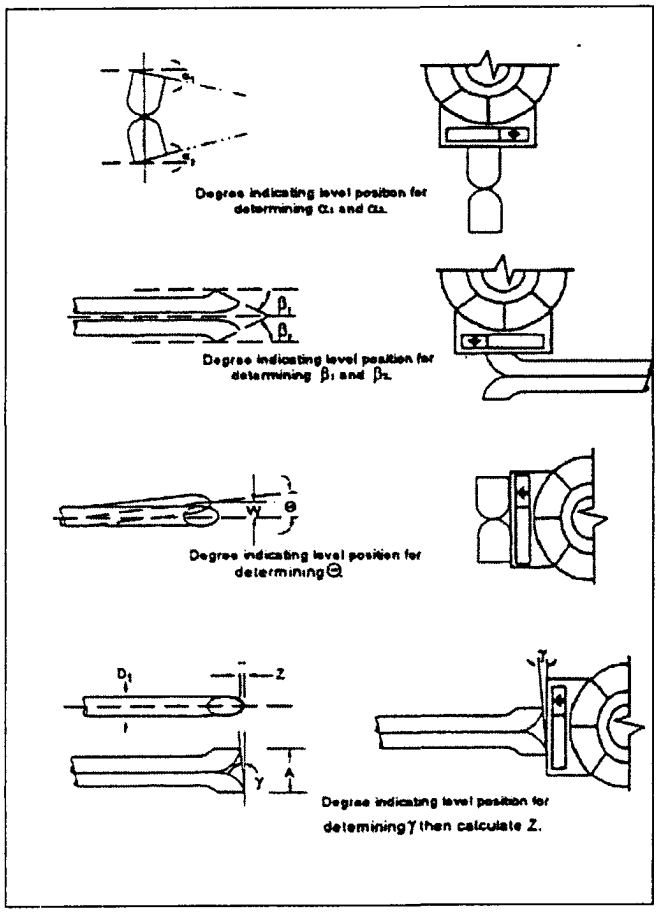
$$\Delta H@i = \frac{0.9244}{K_m^{\,2}}$$

$$K_m = Q_m \sqrt{\frac{(P_b)(29)}{(T_{do} + 460)(\Delta H)}}$$

$$Q_m = \frac{(V_d)(T_{do} + 460)}{(\text{Time})(T_{do} + 460)}$$

CATALYST AIR MANAGEMENT, INC. (865) 531-0075
Air Quality Testing Services (865) 531-0750 Fax
2505 Byington-Solway Road
Knoxville, TN 37931

"S" TYPE PITOT TUBE CALIBRATION – INSPECTION



ATTRIBUTE

Level and Perpendicular?	yes
Obstructed?	no
Damaged?	no
α_1 (-10° ≤ α_1 ≤ +10°)	1.0
α_2 (-10° ≤ α_2 ≤ +10°)	4.0
β_1 (-5° ≤ β_1 ≤ +5°)	2.0
β_2 (-5° ≤ β_2 ≤ +5°)	2.0
γ	0
θ	0
Z = A tan γ (≤ 0.125")	0
W = A tan θ (≤ 0.0.03125")	0
D_1 (3/16" ≤ D_1 ≤ 3/8")	0.250
A	0.619
$A/2D_1$ (1.05 ≤ P_A/D_1 ≤ 1.5)	1.24

QA / QC Check
Completeness ✓ Legibility ✓ Accuracy ✓ Specifications ✓ Reasonableness ✓

Certification:
I certify that the Type "S" pitot tube / probe. ID# CAM 21 meets or exceeds all specifications criteria and or applicable design features and is hereby assigned a pitot tube calibration factor of C_p of 0.84

Certified By: Hayden Dove 6/4/05 **Team Leader** [signature] 6/5/05
Personnel (Signature / Date — Team Leader (Signature / Date

CATALYST AIR MANAGEMENT, INC.

NOZZLE CALIBRATION SHEET

Client: EICPC
Job No: 158-052

Nozzle No. 25

1ST	2ND	3RD	AVG	
0.250	0.250	0.250	0.250	6-14-05

Nozzle No. 27

1ST	2ND	3RD	AVG	
0.250	0.250	0.250	0.250	6-14-05

Nozzle No. 30

1ST	2ND	3RD	AVG	
0.250	0.250	0.250	0.250	6-14-05

Nozzle No. 50

1ST	2ND	3RD	AVG	
0.220	0.220	0.220	0.225	6-15-05

Nozzle No. 43

1ST	2ND	3RD	AVG	
0.280	0.280	0.280	0.280	6-16-05

Nozzle No. 51

1ST	2ND	3RD	AVG	
0.280	0.280	0.280	0.280	6-16-05

105

0.280	0.280	0.280	0.280	6-16-05

Calibrated By: MT
Date: 6-14/15/16/05

CATALYST AIR MANAGEMENT, INC

K-TYPE THERMOCOUPLE CALIBRATION

Post test Calibration Check
EKPC

DATE: 8/22/2005
CALIBRATED BY: Love

AVG STACK TEMPERATURE: 111

Thermocouple No;	**CAM 21**
Std Therometer	110
Thermocouple	110
Difference	0

APPENDIX 7
SAMPLE CALCULATIONS

SAMPLE EQUATIONS
FOR ISOKINETIC SAMPLING

CALCULATIONS FOR FLUE GAS VOLUME AND ISOKINETIC RATIO

Time	Dry Gas Meter Ft^3	Pitot ΔP In. H_2O	Orifice ΔH In. H_2O	Dry Gas Temp.°F In	Dry Gas Temp.°F Out	Flue Gas Static Pressure In. H_2O	Stack Temp.°F
T	V_m	Δp	ΔH	TMI	TMO	P_g	T_s

1. D_n = Nozzle Diameter (inches)

1a. A_n = Area of Nozzle (ft^2)

2. P_{bar} = Barometric Pressure (in. Hg)

3. TT = Net Sampling Time (minutes)

4. V_m = V_m Final - V_m Initial = Sample Gas Volume (Ft^3)

5. T_m = Average Dry Gas Temperature at Meter (°F)

$$T_m = \frac{Avg.TMI + Avg.TMO}{2}$$

6. Δp = Velocity head of stack gas (in. H_2O)

7. ΔH = Average Orifice Pressure Drop (in.H_2O)

8. Volume of dry gas sampled at standard conditions[a] (DSCF)

$$V_{m(std)} = \frac{(17.64)(V_m)(Y)\left(P_{bar} + \frac{\Delta H}{13.6}\right)}{(T_m + 460)}$$

9. V_{lc} = Total Water Collected = gm H_2O Silica gel + ml Imp. H_2O = ml

10. Volume of water vapor at standard conditions[b] (SCF)

$$V_{w(std)} = 0.0471(V_{lc}) = SCF$$

11. Percent moisture in flue gas

$$\%M = \frac{100(V_{w(std)})}{V_{m(std)} + V_{w(std)}}$$

12. Mole fraction of water vapor in flue gas

$$B_{ws} = \frac{\%M}{100}$$

13. Molecular Weight of dry flue gas

$$M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2 + \%CO)$$

13a. %EA = % Excess Air =

$$\frac{[(\%O_2) - 0.5(\%CO)]}{[0.264(\%N_2)] - [(\%O_2) - 0.5(\%CO)]} x100$$

14. Molecular weight of wet flue gas

$$M_s = M_d(1 - B_{ws}) + 18(B_{ws})$$

15. A = Cross-sectional area of stack (Ft^2)

$$\frac{\pi r^2}{144}$$

16. P_s = Flue gas pressure (in, Hg)

$$P_s = P_{bar} + P_g$$

NOTE: $$P_g(Hg) = \frac{P_g(in.H_2O)}{13.6}$$

17. T_s = Absolute stack temperature (°R)

$$T_s = 460 + t_s$$

18. Flue velocity at stack conditions (FT/SEC)

$$V_s = (K_p)(C_p)\left[\left(\sqrt{\Delta p}\right)avg\right]\sqrt{\frac{T_s(avg)}{P_s * M_s}}$$

C_p = pitot tube coefficient
K_p = pitot tube constant = 85.49ft/sec

19. Flue gas volumetric flow rate at standard conditions[b] (SCFM)

$$Q_s = (V_s)(A)\left(\frac{528}{T_s(avg.)}\right)\left(\frac{P_s}{29.92}\right)(60)$$

20. Flue gas volumetric flow rate at standard conditions[c] (DSCFM)

$$Q_{sd} = (1 - B_{ws})(V_s)(A)\left(\frac{528}{T_s(avg.)}\right)\left(\frac{P_s}{29.92}\right)(60)$$

21. Flue gas volumetric flow rate at stack conditions (ACFM)

$$Q_a = (V_s)(A)(60)$$

22. Percent Isokinetic

$$\%I = \frac{K_4(T_s)(V_{m(std)})}{P_s V_s A_n \Theta(1 - B_{ws})}$$

$K_4 = 0.09450$
$\Theta = time(\text{min})$

NOTES: [a]Dry standard cubic feet at 68°F, 29.92 in. Hg
[b]Standard conditions at 68°F, 29.92 in. Hg
[c]Dry standard cubic feet per minute at 68°F, 29.92 in. Hg

II. Calculations for grain loading and emission rates

23. Particulate (gr/DSCF)

$$gr / DSCF = 0.01543\left(\frac{mg}{V_{m(std)}}\right)$$

24. Particulate at stack conditions (gr/ACF)

$$gr / ACF = \frac{17.64 gr / DSCF(P_s)(M_d)}{(T_s + 460)}$$

25. Particulate (lbs/hr), concentration method

$$lbs / hr = 0.00857 * gr / DSCF * Q_{sd}$$

26. Particulate (lbs/hr), area method

$$lbs / hr = 0.132 * \frac{particulate(g) * A}{\frac{(D_n)^2}{2} * TT}$$

27. Particulate (lbs/mmBtu)

$$\frac{lbs / hr}{10^6 Btu / hr}$$

28. Particulate (lbs/ton)

$$lbs / ton = \frac{lbs / hr}{tons / hr}$$

29. Particulate (lbs/mmBtu), F-Factor Method

$$\text{Using } O_2 = \frac{(0.01543)(mg)(F - Factor)(20.9)}{(7000)(V_{m(std)})(20.9 - \%O_2)}$$

30. Particulate (gr/dscf) @ % Excess Air

gr/dscf @ % EA = ((100 + %EA)/150) (gr/dscf)

31. Particulate (lbs/mmBtu), F-Factor Method (Continued)

$$\text{Using } CO_2 = \frac{(0.01543)(mg)(F-Factor)(100)}{(7000)(V_{m(std)})(\%CO_2)}$$

32. F-Factor (dscf/mmBtu)

Wet Basis (F_w)

$$F_w = \frac{10^6\, Btu/mmBtu\left[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O_2)+0.21(\%H_2O)\right]}{GCV_w}$$

Dry Basis (F_d)

$$F_d = \frac{10^6\, Btu/mmBtu\left[3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O_2)\right]}{GCV_d}$$

Carbon Basis (F_c)

$$F_c = \frac{10^6\, Btu/mmBtu\left[0.321(\%C)\right]}{GCV_d}$$

III. Calculations for emission rates (trace metals)

33. Total train mass (μg), M_t

$$M_t\ (\mu g) = (M_{fh} - M_{fhb}) + (M_{bh} - M_{bhb})$$

M_t = Total mass of each metal collected in the sample train, μg
M_{fhb} = Blank correction value of metal in front half, μg
M_{bhb} = Blank correction value of metal in back half, μg

34. Concentration (mg/dscm), Cs

$$Cs\ (mg/dscm) = (K_4 * M_t)/(Vm(std))$$

Cs = Concentration of metal in the stack gas, mg/dscm
$K_4 = 10^{-3}$ mg/μg
M_t = Total mass of each metal collected in the sample train, μg
Vm (std) = Volume of dry gas sampled corrected to standard conditions, dscm

35. Emission Rate (lb/hr), E

$$E\ (lb/hr) = Cs * Qs * 60 * (2.205 * 10^{-6}) * 0.02832$$

E = Emission rate of metal in the stack gas, lb/hr
Cs = Concentration of metal in the stack gas, mg/dscm
Qs = Volumetric flow rate of stack gas, dscm/m
60 = Minutes in an hour
$2.205 * 10^{-3}$ = Conversion factor for lb to mg
0.02832 = Conversion factor for dscm to dscf

IV. Calculations for emission rates (Hydrogen Halide or Halogen)

36. Mass (mg), M_{Hx}

$$M_{Hx}\ (\mu g) = K\ Vs\ (S_{x-} - B_{x-})$$

M_{Hx} = Mass of hydrogen halide in sample, μg/ml
K_{HCl} = 1.028, (μg HCl/μg-mole)/(μg Cl-/μg-mole)
K_{HF} = 1.053, (μg HF/μg-mole)/(μg F-/μg-mole)
Vs = Volume of diluted sample, ml
S_{x-} = Analysis of Sample, mass μg
B_{x-} = Analysis of Blank, mass μg

37. Mass (mg), M_{x2}

$$M_{x2}\ (\mu g) = Vs\ (S_{x-} - B_{x-})$$

M_{x2} = Mass of halogen in sample, μg/ml
Vs = Volume of diluted sample, ml
S_{x-} = Analysis of Sample, mass μg
B_{x-} = Analysis of Blank, mass μg

38. Concentration (gr/DSCF)

$$gr / DSCF = (MHx, Mx2)0.01543\left(\frac{mg}{V_{m(std)}}\right)$$

39. Emission rate (lbs/hr), concentration method

$$lbs / hr = 0.00857 * gr / DSCF * Q_{sd}$$

40. Emission Rate (lbs/mmBtu), F-Factor Method

$$\text{Using } O_2 = \frac{(0.01543)(mg)(F - Factor)(20.9)}{(7000)(V_{m(std)})(20.9 - \%O_2)}$$

V. Calculations for emission rates (acid mist)

41. H_2SO_4 (lb/DSCF)

$$lb/DSCF = K2(N(Vt - Vtb)\left(\frac{Vsol}{Va}\right)/Vmstd)$$

K2 = 1.081 x 10^{-4}

42. SO_2 (lb/DSCF)

$$lb/DSCF = K2(N(Vt - Vtb)\left(\frac{Vsol}{Va}\right)/Vmstd)$$

K2 = 7.061 x 10^{-5}

43. Acid Mist (lbs/hr), concentration method

$$lbs/hr = (lb/DSCF)(Qstd)(60)$$

CALCULATIONS FOR GAS CONCENTRATION

GAS CONCENTRATION (C_{gas})

$$C_{gas} = \left(\overline{C} - C_0\right)\left(\frac{C_{ma}}{C_m - C_o}\right)$$

C_{gas}	=	Effluent gas concentration, ppm
$\overline{C}$	=	Average gas concentration indicated by gas analyzer, dry basis, ppm
C_0	=	Average of initial and final system calibration bias check responses for the zero gas, ppm
C_m	=	Average of initial and final system calibration bias check responses for the upscale calibration gas, ppm
C_{ma}	=	Actual concentration of the upscale calibration gas, ppm

GAS CONCENTRATION @ 3% O_2 (C_{gas} @ 3% O_2)

$$C_{gas} @ 3\% O_2 = C_{gas} * ((20.9-3)/(20.9-\%O_2))$$

GAS CONCENTRATION @ 7% O_2 (C_{gas} @ 7% O_2)

$$C_{gas} @ 7\% O_2 = C_{gas} * ((20.9-7)/(20.9-\%O_2))$$

GAS CONCENTRATION @ 15% O_2 (C_{gas} @ 15% O_2)

$$C_{gas} @ 15\% O_2 = C_{gas} * ((20.9-15)/(20.9-\%O_2))$$

CALCULATION FOR EMISSION RATE USING "F" FACTOR

1. **EMISSION RATE *E(lb/mmbtu)*, *O_2* based** $E(lb/mmbtu) = C \times F_d \left(\frac{20.9}{20.9 - \%O_2} \right)$

Where:

C(lb/dscf) = Pollutant concentration (ppm) x conversion factor.

Conversion Factors:

NOx = 1.194×10^{-7}

SO_2 = 1.660×10^{-7}

CO = 7.274×10^{-8}

CH_4 = 3.894×10^{-8}

C_3H_8 = 1.145×10^{-7}

F_d(dscf/mmbtu) = "F" Factor for fuel type, (Ref. EPA Method 19)

F_d (Coal) = 9780

F_d (Gas) = 8710

F_d (Oil) = 9190

2. **EMISSION RATE *E(lb/mmbtu)*, *CO_2* based** $E(lb/mmbtu) = C \times F_c \left(\frac{100}{\%CO_2} \right)$

Where:

C(lb/dscf) = Pollutant concentration (ppm) x conversion factor.

Conversion Factors:

NOx = 1.194×10^{-7}

SO2 = 1.660×10^{-7}

CO = 7.274×10^{-8}

CH_4 = 3.894*10^-8

C_3H_8 = 1.145×10^{-7}

F_c(dscf/mmbtu) = "F" Factor for fuel type, (Ref. EPA Method 19)

F_c (Coal) = 1800

F_c (Gas) = 1040

F_c (Oil) = 1420

Run 1 PM
Baseline

CALCULATION QUALITY ASSURANCE CHECK

$$V_{mstd} = \frac{(1.005)(17.64)(40.260)(29.44 + 1.691/13.6)}{(460 + 73)} = 39.565$$

$$V_{wstd} = (0.0471)(121.2) = \cancel{0.57085}\ 5.7085$$

$$\%M = (100)(5.7085) / (\cancel{5.07}\ 5.7085 + 39.565) = 12.61$$

$$B_{ws} = \cancel{100/12.61}\ 12.61/100 = 0.1261$$

$$M_d = 0.44(13.8) + 0.32(5.3) + 0.28(100 - 5.3 - 13.8) = 30.42$$

$$M_s = (30.42)(1 - 0.1261) + 18(0.1261) = 28.85$$

$$P_s = 29.44 + (-0.86/13.6) = 29.38$$

$$T_s = 170 + 460 = 630$$

$$V_s = (0.84)(85.49)(1.210)\sqrt{\frac{630}{(29.38)(28.85)}} = 74.9$$

$$Q_{std} = (74.9)(60)(1 - 0.1261)(176.7)\left(\frac{528}{630}\right)\left(\frac{29.38}{29.92}\right) = 570988$$

$$\%I = \frac{(0.0945)(630)(39.565)}{(74.9)(1 - 0.1261)(29.38)(60)(2.10 \times 10^{-4})} = 97.4$$

$$gr/dscf = 0.01543\left(6.9/39.565\right) = 0.003$$

$$lb/mmBtu = \frac{(0.003)(9780)}{7000}\left(20.9/(20.9 - 5.3)\right) = 0.005$$

Run 1 NOx

CALCULATION QUALITY ASSURANCE CHECK

$C_{NO_x} = (58.44 - 0.18)(45.3/(45.36 - 0.18)) = 58.4$

$C_{SO_2} = (54.49 - 0.87)(125.0/(126.255 - 0.87)) = 53.4$

$C_{CO} = (65.39 - 0.365)(30.43/(29.91 - 0.365)) = 67.0$

$C_{O_2} = (5.47 - 0.005)(12.47/(12.415 - 0.005)) = 5.5$

$E_{NO_x} = (58.4)(9780)(1.194 \times 10^{-7})(20.9/(20.9 - 5.5)) = 0.093$

$E_{SO_2} = (53.4)(9780)(1.660 \times 10^{-7})(20.9/(20.9 - 5.5)) = 0.118$

$E_{CO} = (67.0)(9780)(2.274 \times 10^{-8})(20.9/(20.9 - 5.5)) = 0.065$

Run 1 Metals

CALCULATION QUALITY ASSURANCE CHECK

$$V_{mstd} = \frac{(17.64)(1.00)(104.146)(29.35 + 2.750/13.6)}{(81 + 460)} = 100.400$$

$$V_{wstd} = (0.0471)(353.7) = 16.6593$$

$$\%M = (100)(16.6593) / (16.6593 + 100.400) = 14.23$$

$$B_{ws} = 14.23/100 = 0.1423$$

$$M_d = 0.44(13.8) + 0.32(5.2) + 0.28(100 - 5.2 - 13.8) = 30.42$$

$$M_s = (30.42)(1 - 0.1423) + 18(0.1423) = 28.65$$

$$P_s = 29.35 + (-1.10/13.6) = 29.27$$

$$T_s = 460 + 166 = 626$$

$$V_s = (0.84)(85.49)(1.286)\sqrt{\frac{626}{(29.27)(28.65)}} = 79.8$$

$$Q_{std} = (79.8)(60)(1 - 0.1423)(176.7)\left(\frac{528}{626}\right)\left(\frac{29.27}{29.92}\right) = 598834$$

$$\%I = \frac{(0.09450)(626)(100.400)}{(79.8)(120)(29.27)(1 - 0.1423)(2.57 \times 10^{-4})} = 96.2$$

$$\frac{g\ \cancel{mg/dscm}}{Be} = (0.01543)(0.00010/100.400) = 1.54 \times 10^{-8}$$

gr/dscf Be

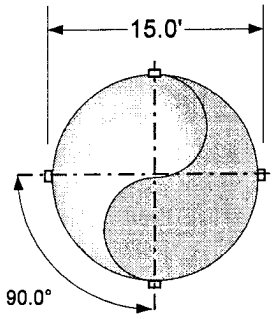
$$lb/mmBtu = \frac{(1.54 \times 10^{-8})(9780)}{7000}(20.9/(20.9 - 5.2)) = 2.96 \times 10^{-8}$$

APPENDIX 8
FIGURES

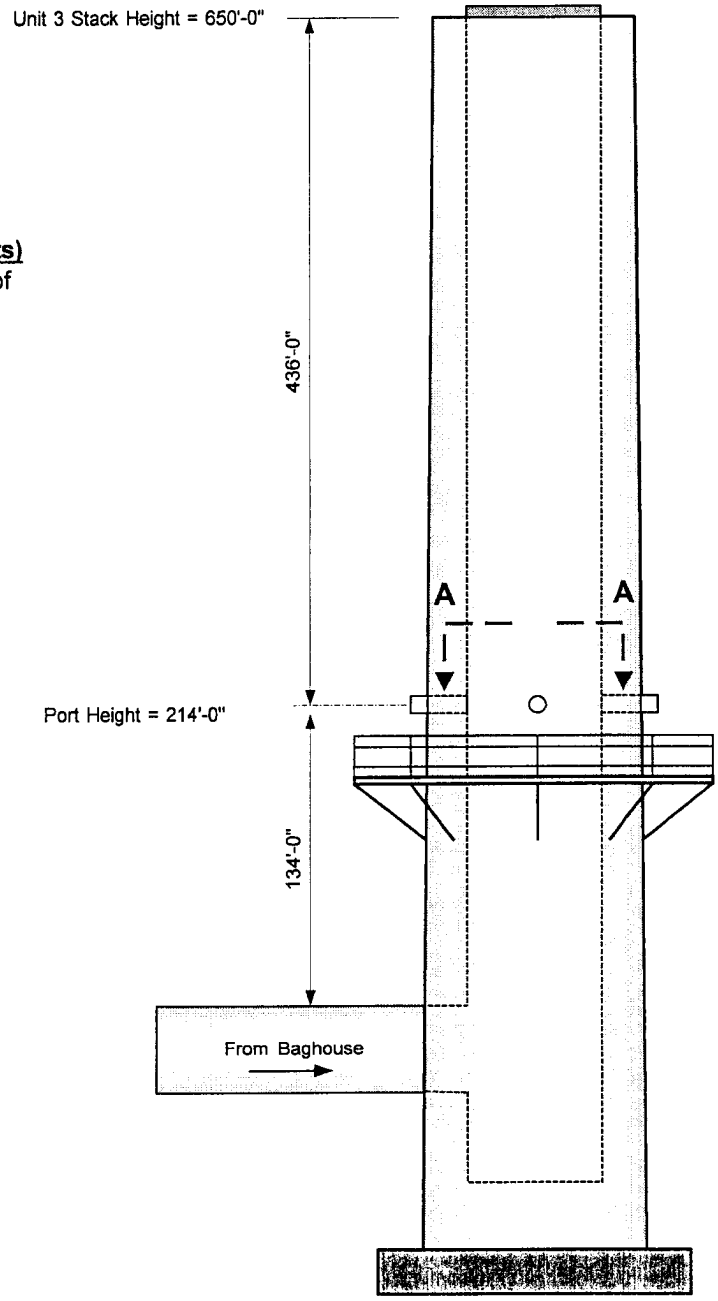
CATALYST
AIR MANAGEMENT, INC.

TRAVERSE POINTS (Typ 4 Ports)
Particulate (Inches) from inside of stack.

1. 7.92"
2. 26.28"
3. 53.28"

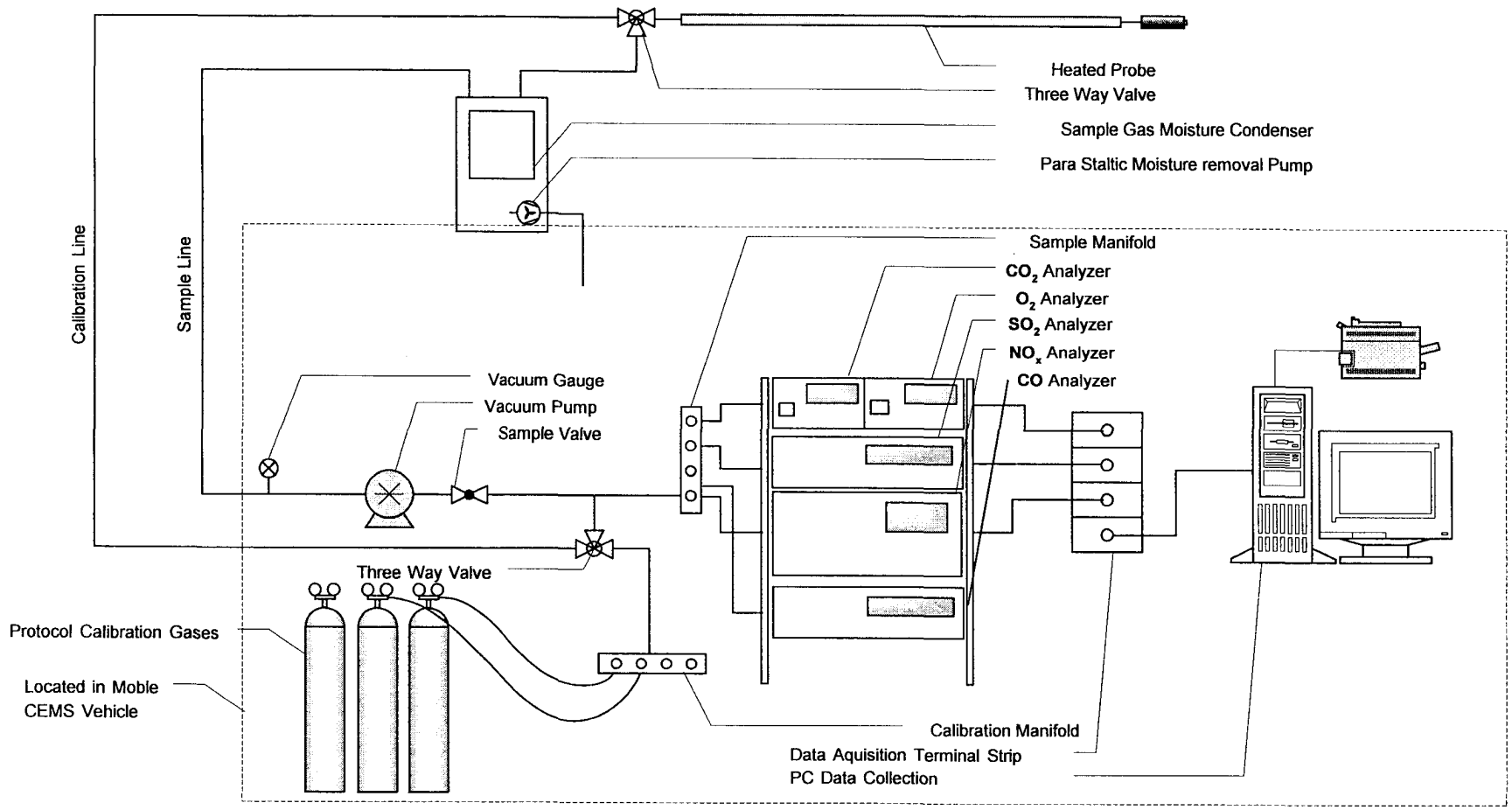


SECTION A - A



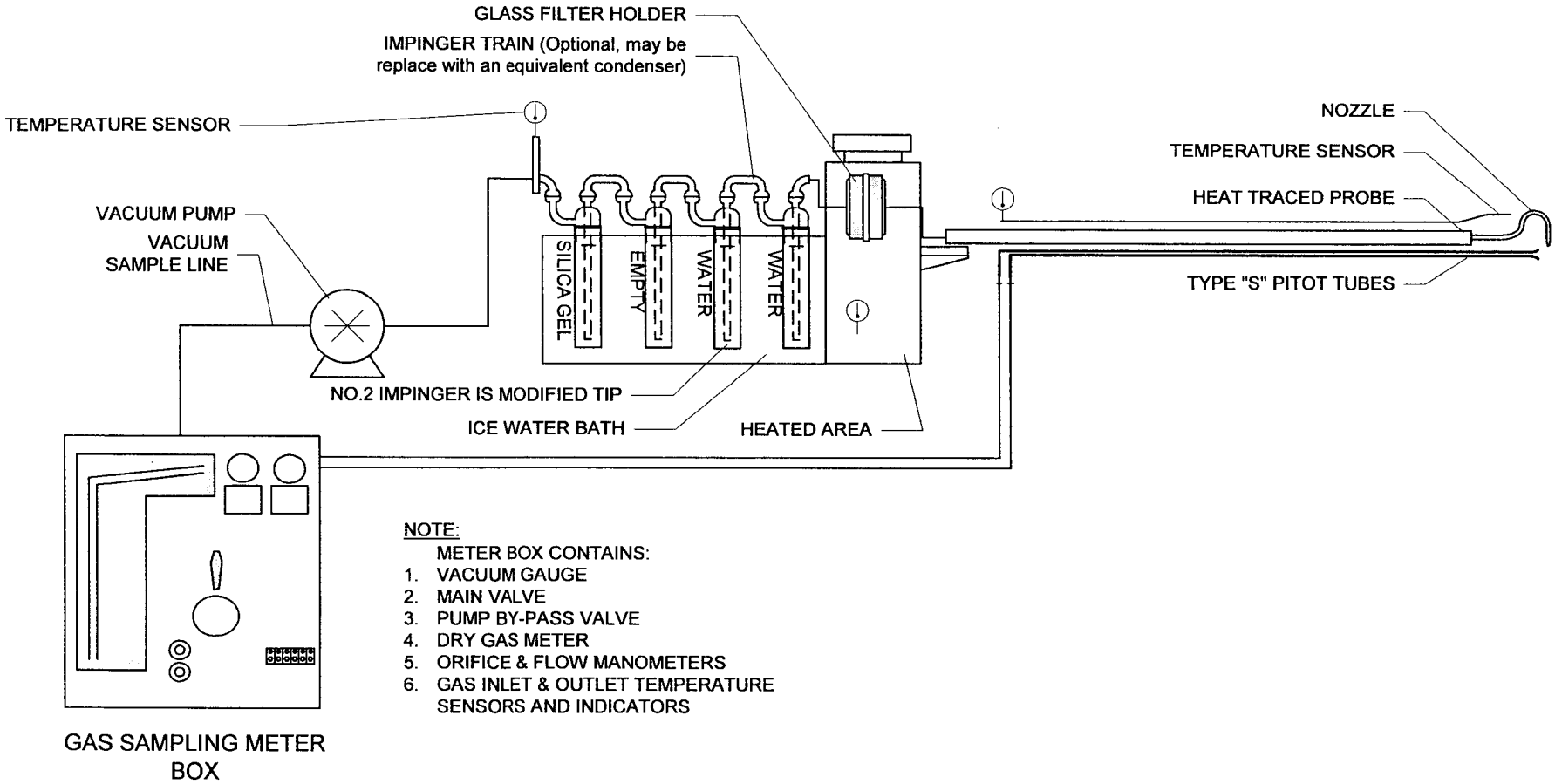
TITLE **EAST KENTUCKY POWER COOPERATIVE - SPURLOCK STATION**		
DESCRIPTION **UNIT NO. 3 STACK TEST PORT CONFIGURATION**		DATE 11/29/04
SCALE NONE	DRAWN BY MJ TAYLOR	REVISED

CATALYST
AIR MANAGEMENT, INC.



TITLE		
EPA INSTRUMENTAL SAMPLE TRAIN		
DESCRIPTION		DATE
SAMPLE TRAIN SCHEMATIC		01-26-98
SCALE	DRAWN BY	REVISED
NONE	RF COBB	

CATALYST
AIR MANAGEMENT, INC.

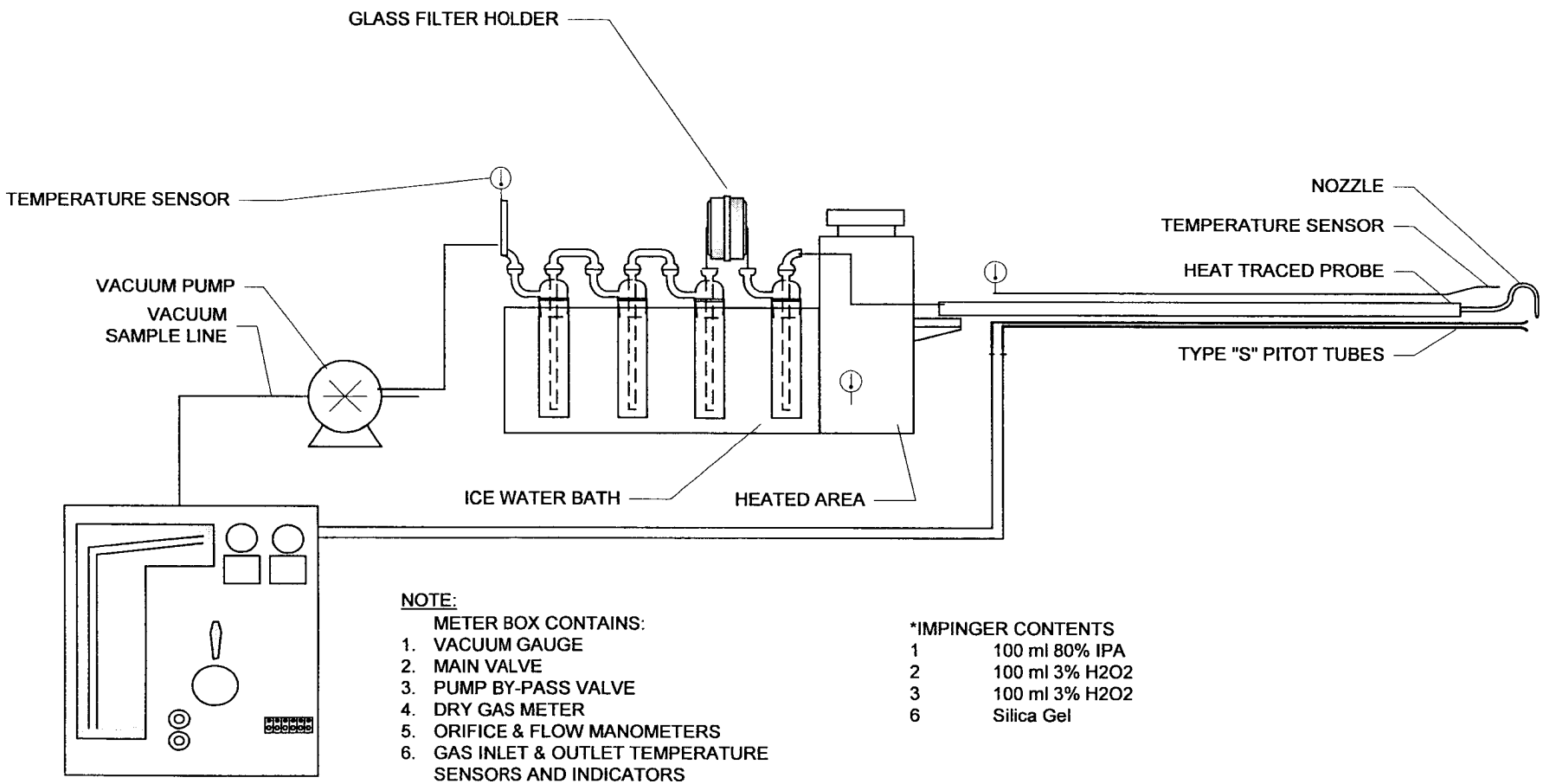


GAS SAMPLING METER BOX

NOTE:
METER BOX CONTAINS:
1. VACUUM GAUGE
2. MAIN VALVE
3. PUMP BY-PASS VALVE
4. DRY GAS METER
5. ORIFICE & FLOW MANOMETERS
6. GAS INLET & OUTLET TEMPERATURE SENSORS AND INDICATORS

TITLE		
EPA METHOD 5 SAMPLING TRAIN		
DESCRIPTION		DATE
PARTICULATE SAMPLE TRAIN		01-26-98
SCALE	DRAWN BY	REVISED
NONE	RF COBB	8/22/2005

CATALYST
AIR MANAGEMENT, INC.



GAS SAMPLING METER BOX

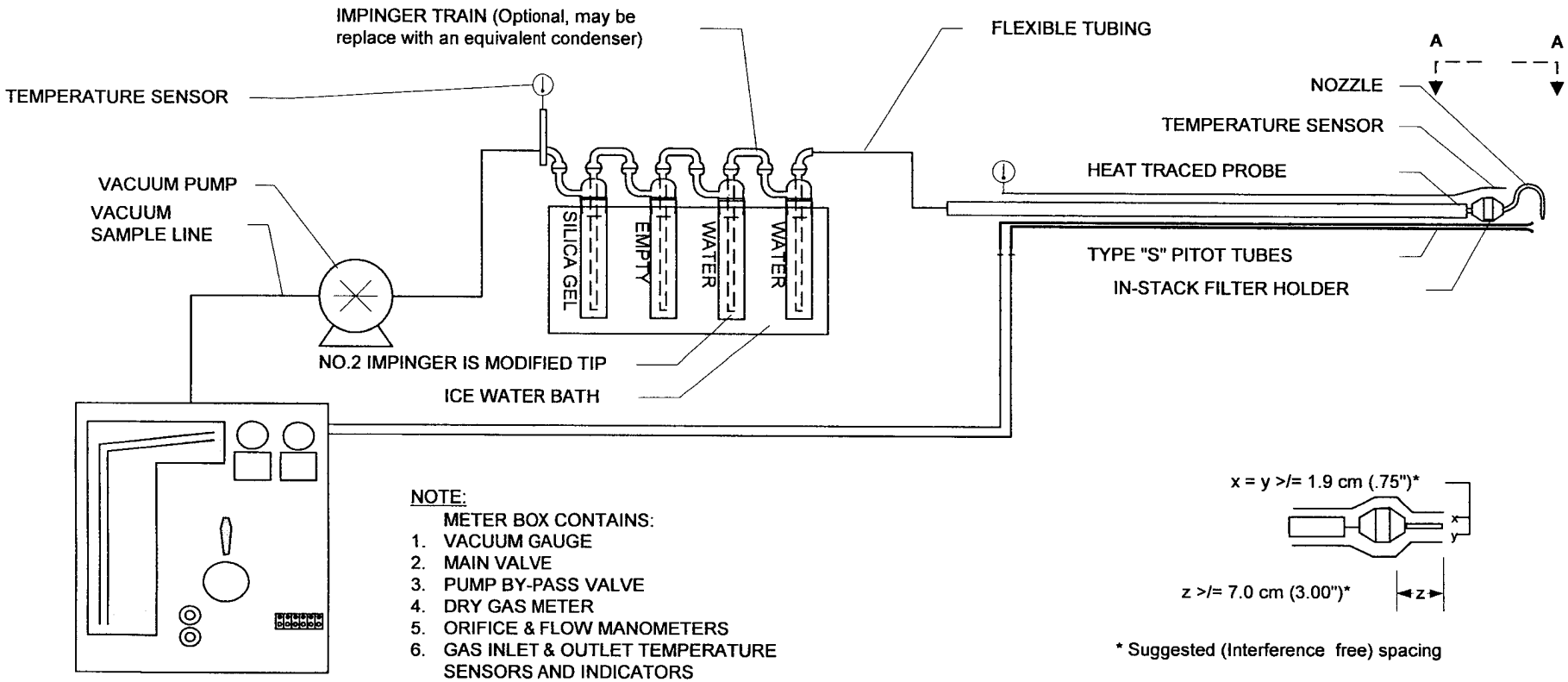
NOTE:
METER BOX CONTAINS:
1. VACUUM GAUGE
2. MAIN VALVE
3. PUMP BY-PASS VALVE
4. DRY GAS METER
5. ORIFICE & FLOW MANOMETERS
6. GAS INLET & OUTLET TEMPERATURE SENSORS AND INDICATORS

*IMPINGER CONTENTS

1	100 ml 80% IPA
2	100 ml 3% H_2O_2
3	100 ml 3% H_2O_2
6	Silica Gel

TITLE		
EPA METHOD 8 SAMPLING TRAIN		
DESCRIPTION		DATE
SULFURIC ACID MIST SAMPLE TRAIN		01-26-99
SCALE	DRAWN BY	REVISED
NONE	MJ TAYLOR	

CATALYST
AIR MANAGEMENT, INC.



GAS SAMPLING METER BOX

NOTE:
METER BOX CONTAINS:
1. VACUUM GAUGE
2. MAIN VALVE
3. PUMP BY-PASS VALVE
4. DRY GAS METER
5. ORIFICE & FLOW MANOMETERS
6. GAS INLET & OUTLET TEMPERATURE SENSORS AND INDICATORS

* Suggested (Interference free) spacing

Section A-A
Scale: NONE

TITLE		
EPA METHOD 17 SAMPLING TRAIN		
DESCRIPTION		DATE
PARTICULATE SAMPLE TRAIN		01-26-98
SCALE	DRAWN BY	REVISED
NONE	RF COBB	1/17/2005

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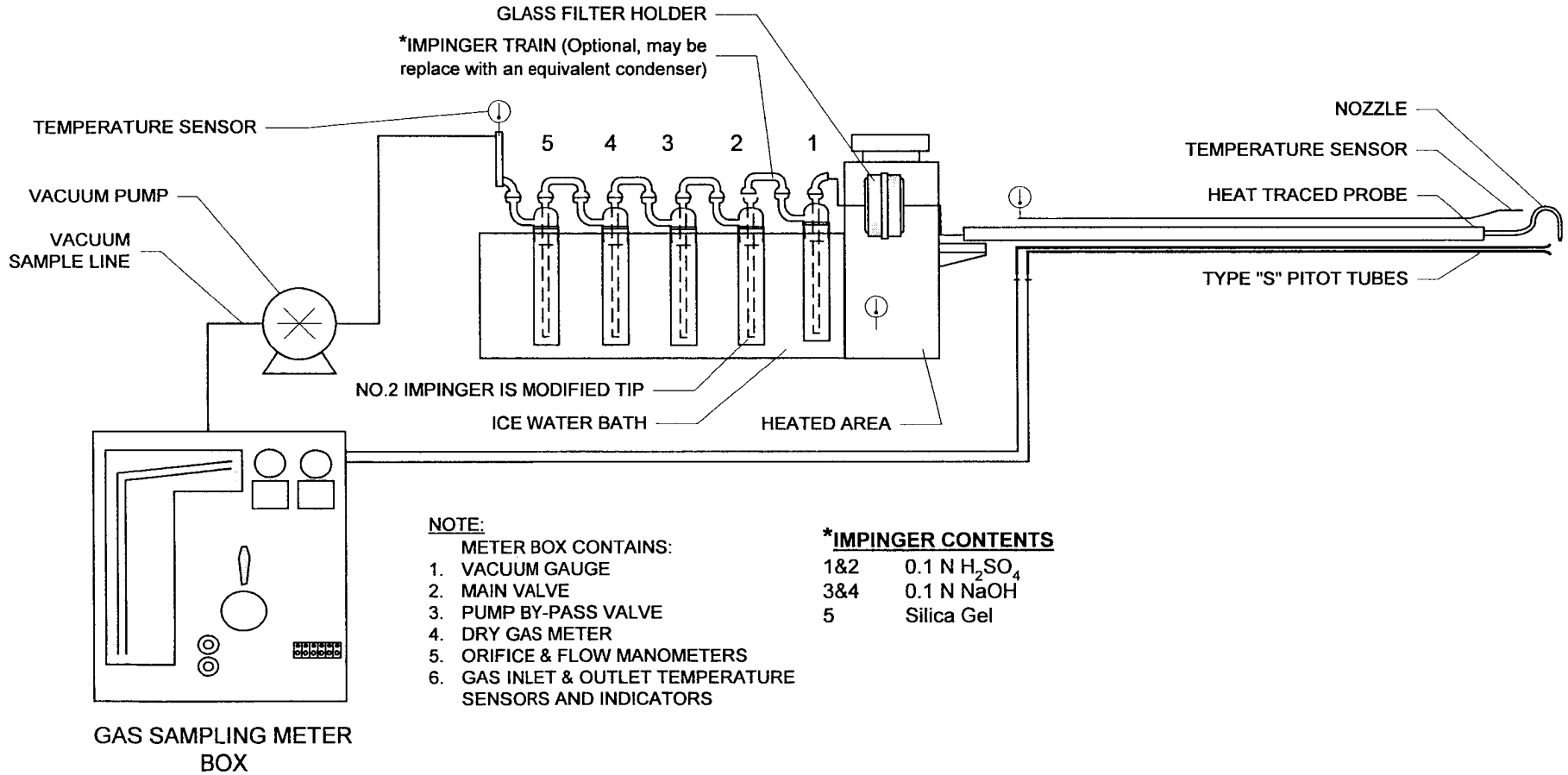
CATALYST
AIR MANAGEMENT, INC.



GAS SAMPLING METER BOX

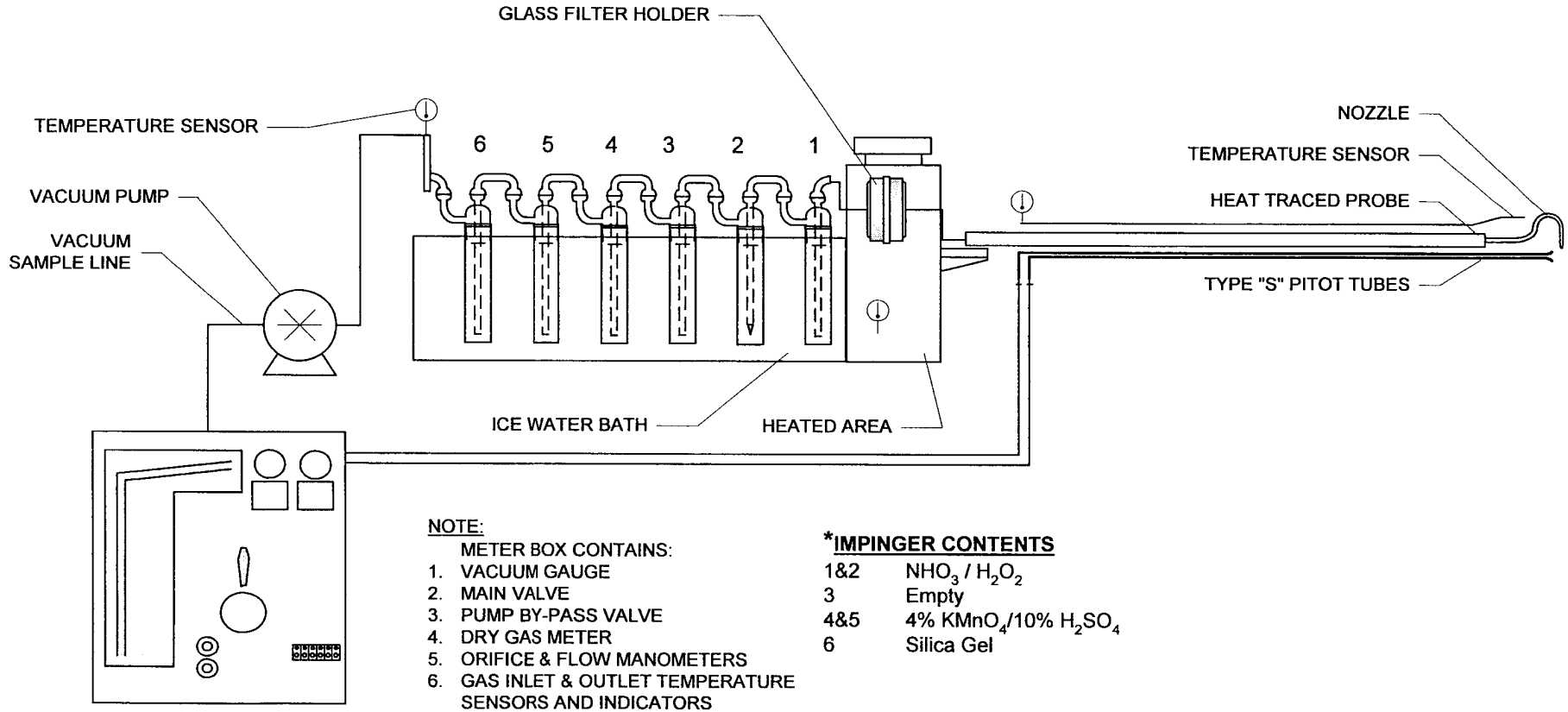
NOTE:
METER BOX CONTAINS:
1. VACUUM GAUGE
2. MAIN VALVE
3. PUMP BY-PASS VALVE
4. DRY GAS METER
5. ORIFICE & FLOW MANOMETERS
6. GAS INLET & OUTLET TEMPERATURE SENSORS AND INDICATORS

***IMPINGER CONTENTS**

1&2	0.1 N H_2SO_4
3&4	0.1 N NaOH
5	Silica Gel

TITLE		
EPA METHOD 26A SAMPLING TRAIN		
DESCRIPTION		DATE
HCL/HF SAMPLE TRAIN CONFIGURATION		04-26-99
SCALE	DRAWN BY	REVISED
NONE	MJ TAYLOR	

CATALYST
AIR MANAGEMENT, INC.



GAS SAMPLING METER BOX

NOTE:
METER BOX CONTAINS:
1. VACUUM GAUGE
2. MAIN VALVE
3. PUMP BY-PASS VALVE
4. DRY GAS METER
5. ORIFICE & FLOW MANOMETERS
6. GAS INLET & OUTLET TEMPERATURE SENSORS AND INDICATORS

***IMPINGER CONTENTS**

1&2	NHO_3 / H_2O_2
3	Empty
4&5	4% $KMnO_4$/10% H_2SO_4
6	Silica Gel

TITLE		
EPA METHOD 29 SAMPLING TRAIN		
DESCRIPTION		DATE
MULTIPLE METALS SAMPLING CONFIGURATION		01-26-98
SCALE	DRAWN BY	REVISED
NONE	RF COBB	8/29/2005

	Supplier	Filter	Mass/area (oz./yd.)	Outlet PM2.5 Concentration (gr/dscf)	Description	Status
	Hamon Research -Cottrell, Inc	SunCoke proposed bag (PPS)	18	n/a, guarantee 0.005 PM		never verified
	BWF America, Inc's	Grade 700 MPS Polyester Felt	18	0.0000086	micro-pore-size, high-efficiency, scrim-supported felt, singed cake side	currently verified
	Donaldson Company, Inc.	Tetratec #6255 Filtration Media	22	0.0000090	woven fiberglass with Tetratex PTFE membrane	currently verified
	Donaldson Company, Inc.	6277 Filtration Media	8	0.0000034	Polyester Spunbond with Tetratex PTFE membrane	currently verified
	Donaldson Company, Inc.	6282 Filtration Media	10	0.0000020	Pleatable polyphenylene sulfide (PPS) with Tetratex PTFE membrane	currently verified
	Southern Filter Media, LLC	PE-16/M-SPES Filter	16	0.0000220	singed Micro-Denier polyester felt	currently verified
	W.L. Gore & Associates, Inc.	L3650 Filter	22	0.0000070	membrane/fiberglass fabric laminate	currently verified
	Air Purator Corp.	Huyglas 1405M Filter	22	0.0000065	PTFE film applied to a glass felt	prev. verified
	Albany International Corp.	Primatex Plus I Filter	16	0.000014	polyethylene terephthalate filtration fabric with fine fibrous surface layer	prev. verified
	BASF Corp.	AX/BA-14/9-SAXP Filter	14	0.00011		prev. verified
GE	BHA Group, Inc.	QG061 Filter		0.0000009	woven-glass-base fabric with an expanded, micro porous PTFE membrane	prev. verified
GE	BHA Group, Inc.	QP131 Filter		0.000003	polyester needle felt substrate with an expanded, micro porous PTFE membrane	prev. verified
	BWF America, Inc.	Grade 700 MPS Polyester Felt Filter	18-20	0.0000045	micro-pore size high efficiency scrim supported felt, singed cake side	prev. verified
	Inspec Fibres	5512BRF Filter	16	0.00016	100% scrim supported P84 needle felt	prev. verified
	Menardi-Criswell	50-504 Filter	16	0.0000083	singed microdenier polyester felt	prev. verified
	Polymer Group, Inc.	DURAPEX PET Filter	10	0.0000185	100 percent polyester, non-woven fabric, non-scrim supported	prev. verified
	Standard Filter Corp.	PE16ZU Filter		0.0000041	stratified microdenier polyester non-woven	prev. verified
	Tetratec PTFE Technologies	Tetratex 6212 Filter	16	0.0000023	polyester needle felt with Tetratex® expanded PTFE membrane	prev. verified
	Tetratec PTFE Technologies	Tetratex 8005	16	0.000022	polyester scrim-supported needle felt with a Tetratex® expanded PTFE membrane	prev. verified
	W.L. Gore & Associates, Inc.	L4347 Filter		0.0000059	GORE-TEX® ePTFE (expanded polytetrafluoroethylene) membrane/polyester felt laminate	prev. verified
	W.L. Gore & Associates, Inc.	L4427 Filter		0.0000021	GORE-TEX® membrane/polyester felt laminate	prev. verified

Test Procedure
Conditioning period with 10,000 rapid pulse cleaning cycles
Recovery period with 30 normal filtration cycles
Six-hour performance test period
Inlet particle concentration = 18.4± 3.6 g/dscm with average particle size of 1.5 micron diamete
= 8.0 ± 1.6 gr/dscf

**GE acquired and is still selling the BHA Group filters

	Outlet PM2.5 concentration (gr/dscf)		
	Best	Worst	Average
Currently verified	0.000002	0.000022	0.0000087
All verified (including expired)	0.0000009	0.00016	0.0000207

BEFORE THE BOARD OF ENVIRONMENTAL REVIEW OF THE STATE OF MONTANA

IN THE MATTER OF:
SOUTHERN MONTANA ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE —
HIGHWOOD GENERATING STATION

AIR QUALITY PERMIT NO. 3423-00

Report of Expert Witness
Hal Taylor

Feasibility of Conducting PM 2.5 BACT Analysis for the Highwood Generating Station

Submitted on behalf of Appellants
Montana Environmental Information Center
and
Citizens for Clean Energy

September 2007

I. Qualifications

Hal Taylor - Hal Taylor and Associates

I have worked in the pollution control industry for over 35 years and have been involved with the development, design, fabrication, installation, and commissioning of large and small process and emission control systems for both the industrial and utility markets. I have been employed by several capital equipment and consulting firms in capacities ranging from chief engineer to president. My projects have included control equipment for the utility, pulp and paper, and iron and steel industries.

Relevant Experience

Some projects I have been involved with that are relevant to this report include:

- PM2.5 Particle Removal Enhancements at taconite grate kilns.
- Design of nucleation chambers to enhance fine particulate collection efficiencies at lead smelters and glass furnaces.
- Electrostatic precipitator troubleshooting and enhancements to improve fine particulate and aerosol collection prior to a regenerative thermal oxidizer.
- Study of fine particle speciation and formation phenomenon as part of fine particulate control equipment design for copper reclaim furnace.
- Extensive fine particulate study and control equipment design for iron foundry cupolas and steel blast furnaces

I have managed the development, design, installation and commissioning of over 2200 megawatts of utility air pollution control systems. In my capacity as a consulting engineer, I have conducted 92 BACT analyses and 6 MACT analyses for electric utilities, pulp and paper boilers, and coal-fired taconite kilns. I have also provided expert witness testimony on air pollution control equipment issues.

Education

BS Engineering Physics, Nuclear Option
Fenn College of Engineering

II. Issues

Under the implementing rules of the Montana Clean Air Act, "a new, major stationary source shall apply BACT for each pollutant subject to regulation under the FCAA that it would have the potential to emit in significant amounts." [ARM 17.8.819(2)]. Since PM2.5 is a regulated criteria pollutant under the FCAA, SME and the Montana Department of Environmental Quality (MDEQ) were "required to apply BACT" for PM2.5. However, the Highwood permit, does not contain a BACT-determined emission limitation or any other design, equipment, work practice or operational standard for PM2.5. The permit sets forth limits exclusively for filterable particulate and PM10.

BACT - Best Available Control Technology

FCAA - Federal Clean Air Act

PM 10 refers to particulate matter that is less than 10 microns in diameter.

PM 2.5 refers to particulate matter that is less than 2.5 microns in diameter

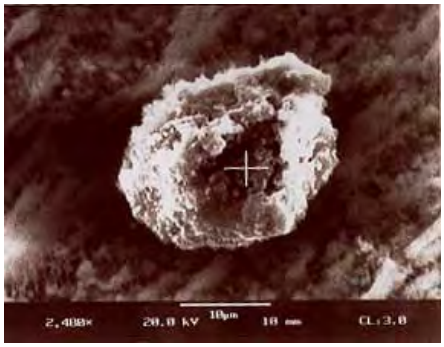
The failure to establish any BACT standard limiting PM 2.5 emissions from the Highwood facility is inconsistent with the plain language of governing legal requirements. In order to assess the practical implications of this omission, I considered what a PM2.5 BACT analysis would entail, and whether imposition of BACT-based permit standards could result in reduced PM 2.5 emissions and resulting reductions in the risk of serious illnesses and premature deaths in Montana.

As discussed in detail below, my conclusions are as follows:

1. There are no longer any regulatory or technical impediments to conducting a BACT analysis for PM 2.5 or for setting a PM 2.5 emission limit. SME could have undertaken a straightforward BACT analysis for PM 2.5 and set an emissions limit based on available control technology that was not considered during the Highwood permitting process.

2. BACT for PM10 is not BACT for PM 2.5, and indeed, BACT for Total Suspended Particulate ("TSP") is not BACT for PM10. Because the efficacy of controls varies with respect to particulate size, it is necessary to address TSP, PM10 and PM2.5 separately. As the U.S. Environmental Protection Agency ("EPA") has made clear, it is no longer permissible to use PM10 as a surrogate for PM2.5.

3. Emission limits for filterable PM and PM 10 in the Highwood permit are not a valid surrogate for BACT-determined PM 2.5 limits.



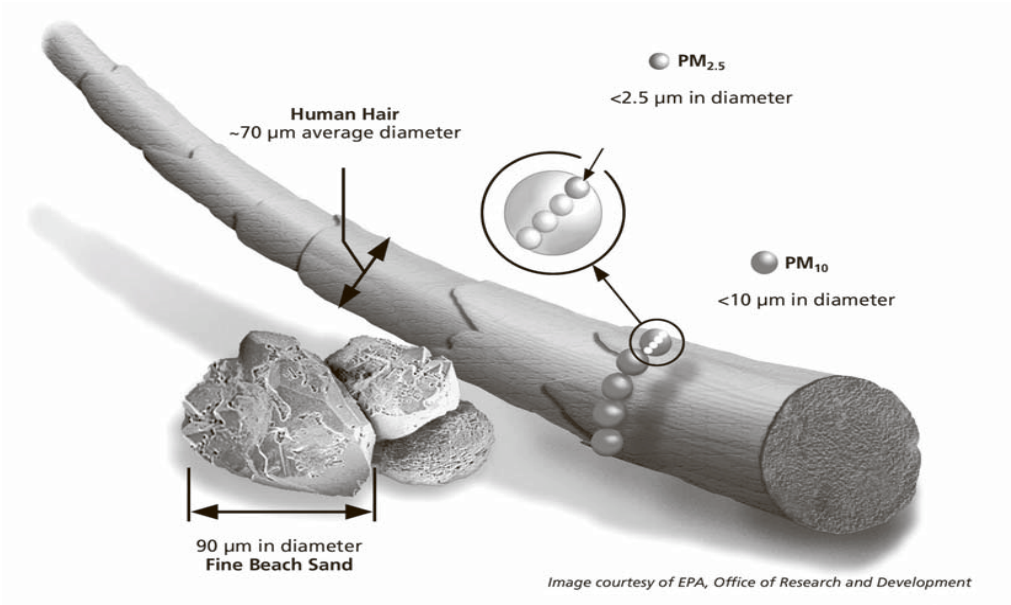
PM 2.5 particle

4. EPA data indicates that failure to require PM 2.5 BACT for the Highwood facility will result in a measurable increase in premature deaths among Montana residents.

III. Background

EPA issued the first National Ambient Air Quality Standard (NAAQS) for particulate matter in 1971. It established ambient air limits for Total Suspended Particulate (TSP), which consists of particles of any size that may be caught in a filter during sampling. This most "coarse" form of particulate matter was targeted by regulation because, at the time, there were no sampling methods available to measure finer particles. Furthermore, there was little or no epidemiological data on health effects for smaller forms of particulate matter.

During the late 1970's and early 1980's, EPA re-evaluated the PM NAAQS. By this time, there was increased data showing that only particulate of less than 10 microns (PM 10) posed serious health effects. Furthermore as sampling technology advanced, it became possible to measure this fraction of particulate matter accurately. In 1987, EPA revoked the NAAQS for TSP and implemented an annual and 24-hour standard for PM10.



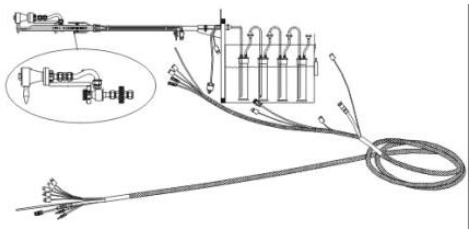
At this point, the status of TSP was uncertain. Since there was no longer a NAAQS standard for TSP, was it still considered a "regulated pollutant"? In 1995, EPA issued a memo to clarify that only PM10 was considered a regulated pollutant since there was no longer a NAAQS for TSP.[1,2]

[1]USEPA.. 1995. Memorandum from Deputy Director L. N. Wegman dated 16 October, 1995 : "Definition of Regulated Pollutant for Particulate Matter for Purposes of Title V.". Office of Air Quality Planning and Standards (MD-10); USEPA; Research Triangle Park, N.C.

[2] This approach was followed in at least one rulemaking when Minnesota's SIP plan was rejected by EPA in part for addressing TSP instead of PM10. [66 FR 54739]

In re-evaluating the PM NAAQS in 1987, EPA realized that filters do not capture all of the particulate matter that is emitted into the ambient air from a given source. Some material is still in gaseous form inside the stack and only condenses into particulate form when cooled to ambient temperatures. This material is called "condensable particulate matter" or CPM. Prior to 1987, this material was not considered a part of TSP. As it turns out, for some sources, CPM emissions are far greater than the filterable emissions. PM10, therefore, is composed of both filterable and condensable fractions. Currently, these must be monitored with different methods.

At the time EPA promulgated the PM10 NAAQS standard, there were no available test methods for measuring the pollutant in the stack. To fill this gap, EPA issued guidance outlining temporary methods until "official" methods could be prescribed in new regulations. In 1990 and 1991, EPA promulgated Reference Methods 201A for filterable PM10 and 202 for condensable PM10. [40 CFR 51, Appendix M]



Filterable PM 10 Sampling System Method 201A

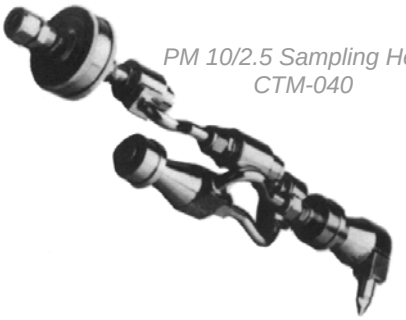
In the early 1990's, EPA began re-evaluating the particulate NAAQS once again in response to numerous epidemiological studies showing adverse health effects from exposure to PM2.5 at concentrations well below then existing NAAQS levels. The data collected for this evaluation indicated that even smaller particulate, PM 2.5, was responsible for many of the observed adverse health effects. Therefore, in 1997, EPA issued a new NAAQS regulating both PM10 and PM2.5.

At the time this NAAQS was promulgated, very little information was available on the distribution of PM 2.5 across the country, how it should be modeled or how it should be measured. To address these uncertainties, John Seitz, then Director of EPA's Office of Air Quality Planning and Standards (OAQPS), issued a memo[3] addressing these three concerns. He stated in this memo that until these issues were satisfactorily resolved, states could rely on

[3]Memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, Interim Implementation of New Source Review for PM2.5 (Oct. 23, 1997)

PM10 as a surrogate for PM2.5 in PSD reviews including BACT analysis.

Over the past decade since EPA issued the so-called "Seitz memo," concerns about measuring and modeling PM 2.5 have been largely resolved. As EPA affirmed in its recently issued implementation rule for PM 2.5, the impediments to generating and using PM2.5 data that were identified in the Seitz memo have been adequately addressed, and they are no longer problems. PM2.5 monitoring stations have been in operation for many years; measurement methods are in place; and adequate modeling techniques have been developed.



PM 10/2.5 Sampling Head CTM-040

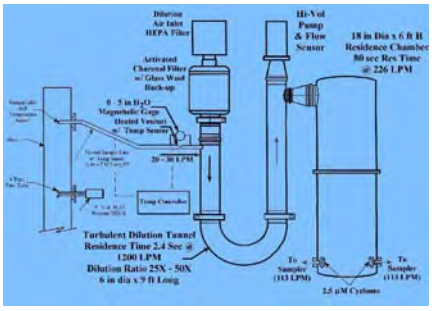
With regard to measurement methods, which are of concern in the BACT context, EPA has issued Conditional Test Method 40 (CTM-040) for filterable PM 2.5[4]. While this is not yet a promulgated test method, it is based on Method 201A (referenced above for PM10), a well established test method that has been formally adopted by EPA. In fact, EPA endorses the use of CTM-040…

[4]see www.epa.gov/ttn/emc/ctm.html

> As for CTM–040, we believe that further validation of this method is unwarranted since the technology and procedures are based upon the same as evaluated for promulgated Method 201A. Method 201A has undergone public review and comment (55 FR 14246, April 17, 1990).

72 FR 20653
Clean Air Fine Particle Implementation Rule; Final Rule

Further, Method 202 is in regular use to measure condensable PM. EPA is now preparing to release a modified version of this method to improve its accuracy and repeatability.



Prototype Dilution Sampling System

EPA is also developing a test method capable of measuring both filterable and condensable particulate. The draft of this method, known as the "dilution method" is available on the EPA website as CTM-039[5].

[5]see www.epa.gov/ttn/emc/ctm.html

In short, there are reliable, field-tested methods available right now to measure PM2.5, and even better methods are already available in draft form.

For this reason, among others, EPA is no longer accepting the use of PM10 as a surrogate for PM2.5. Superseding the Seitz memo, the preamble to EPA's implementation rule[6] expressly states:

[6] *72 FR 20586 Clean Air Fine Particle Implementation Rule; Final Rule*

> In summary, the purpose of the statements made in the preamble to the proposal was to notify sources that as of the promulgation of this final rule, the EPA will no longer accept the use of PM_{10} emissions information as a surrogate for $PM_{2.5}$ emissions information [53] given that both pollutants are regulated by a National Ambient Air Quality Standard and therefore are considered regulated air pollutants.

72 FR 20660 Clean Air Fine Particle Implementation Rule; Final Rule

EPA's rule then clarifies further that PM 2.5 data must be used for PSD analysis:

> Circumstances necessitating the quantification of $PM_{2.5}$ emissions and the submittal of this information include: (1) Determining all of the pollutants for which a source is major; (2) determining whether an applicable requirement or program applies, e.g., determining the applicability of a SIP requirement or a PSD or nonattainment NSR program, etc.; or (3) determining what fees a source owes a permitting authority as a result of considering $PM_{2.5}$ emissions.

72 FR 20659 Clean Air Fine Particle Implementation Rule; Final Rule

Thus, EPA's rule leaves no doubt that PM2.5 must be addressed specifically during the PSD permitting process.

Now that EPA has clarified its position prohibiting PM2.5 surrogates, states are beginning to change their BACT policies. For example, Connecticut recently issued its "Interim PM2.5 New Source Review Modeling Policy And Procedures" document, which states…

> *…for permit applications subject to this policy, a demonstration of compliance with the PM10 NAAQS will no longer serve as a surrogate for compliance with the PM2.5 NAAQS. Instead, NSR permit applicants must consider PM2.5 as a criteria pollutant and address it in preparing an application.*

CTDEP Interim PM2.5 New Source Review Modeling Policy And Procedures, August 22, 2007

This policy covers all NSR/PSD modeling and BACT analyses.

Effective control and monitoring of PM2.5 is urgent in light of EPA's recent revision of the 24-hour PM2.5 NAAQS to be nearly twice as stringent as the originally promulgated 1997 standard.[7]

[7] 71 FR 61144, October 17, 2006 National Ambient Air Quality Standards for Particulate Matter

IV. Findings

Based on a review of the Highwood permit and BACT analysis, SME's permit application, and the expert report of Gary McCutchen, as well as consultation with colleague Scott Evans of Clean Air Engineering, my findings are as follows:

1. There Are No Regulatory or Technical Impediments to Application of BACT to PM2.5

SME relies on the 1997 Seitz memo to assert that PM2.5 BACT analysis is not technically feasible and therefore not required. However, as discussed above, EPA has recognized that impediments to BACT analysis for PM2.5 have been resolved, and for that reason, EPA is no longer accepting information for PM10 in place of data for PM2.5. There is no longer any legitimate reason to ignore PM2.5 under the PSD program.

In fact, far from discouraging states from addressing PM 2.5 directly, EPA states...

Duke Power Cliffside Station with wet ESP

At the same time, however, we note that nothing precludes States from taking early action and we encourage States to take actions to reduce $PM_{2.5}$ concentrations where feasible even before the SIPs are submitted.

72 FR 20616
Clean Air Fine Particle Implementation Rule; Final Rule

The first step in a BACT analysis is to identify technologies, design, and/or operational measures that are effective at controlling PM 2.5. Equipment to control fine particulates, both filterable and condensable, is well established. In fact, one such device, the wet electrostatic precipitator, celebrates its 100th anniversary this year.

Fredrick Cottrell and his wet ESP Circa 1907

A wet ESP placed after the fabric filter would eliminate up to 99% of the 138 tons of filterable PM 2.5 emissions projected in the Highwood facility air permit. In addition, it would eliminate a similar percentage of the 161 tons of condensable PM that this unit will emit. Yet, this approach was not considered in the BACT analysis.

Wet ESPs are installed on other utility boilers such as:

- Xcel Energy, Sherburne County, Units 1 and 2
- First Energy, Mansfield, Unit 2

- Duke Power, Cliffside, Units 6 and 7
- AES, Deepwater (operating since 1986)

Other options can also be considered either as alternatives to or in conjunction with a wet ESP. These may include substitution of membrane bags in the currently planned baghouse or technologies such as W. L. Gore's Advanced Hybrid Filter system that is installed at Otter Tail Power's Big Stone plant in South Dakota.

In addition to consideration of established technologies, it is consistent with EPA's interpretation of BACT that new, innovative technologies also be assessed. EPA has stated that:

> *Efforts to reduce emissions bring about the "technology-forcing" aspect of BACT and lowest achievable emission rate that Congress envisioned as part of a system designed to hold new emissions to an absolute minimum.*

EPA Memorandum, Huntsville Incinerator - Determining Best Available Control Technology (BACT), Gary McCutchen, April 22, 1987

Once the available controls are identified, any qualified engineer can ascertain the implementation costs relatively quickly. Then, the relative costs and benefits of feasible controls may be evaluated in order to establish a BACT-determined permit limitation.

In my opinion, this would be a routine task for SME to accomplish. Over the past 15 years, I have conducted about 100 BACT analyses. Based on my experience, I estimate it would take an engineer about 2-3 days to identify potential technologies, contact the relevant vendors, gather the information on capital and operating costs, and crunch the numbers.

2. SME's Proffered BACT for Filterable PM and Condensable PM10 is not BACT for PM2.5

It is incorrect to assume that PM10 is a reliable surrogate for PM 2.5 in all cases. As EPA stated in its Fine Particulate Implementation Rule…

72 FR 20599
Clean Air Fine Particle Implementation Rule; Final Rule

> $PM_{2.5}$ also differs from PM_{10} in terms of atmospheric dispersion characteristics, chemical composition, and contribution from regional transport.

EPA goes on to state...

> reducing PM_{10} concentrations from certain sources of direct $PM_{2.5}$ emissions can be somewhat effective in certain $PM_{2.5}$ nonattainment areas but not in all.

72 FR 20599
Clean Air Fine Particle Implementation Rule; Final Rule

In large part, this is due to the fact that control technologies for PM10 are often inadequate to effectively capture finer PM2.5.

The permitting process for the Highwood facility is illustrative. In identifying control measures as PM BACT during the Highwood permitting process, SME and MDEQ neglected to consider control measures that would be more effective at controlling PM2.5. Thus, the BACT analysis concludes that a fabric filter is BACT for filterable particulate. because it is very good at removing large heavy particles, but the analysis never confronts the problem that a fabric filter is not so effective with smaller particles, particularly at the sub-micron level.

An analogy may be useful in illustrating this point. Imagine a cup of marbles, a cup of baby powder, and a kitchen strainer. The cup of marbles is much heavier than the cup of baby powder- say 900 g for the marbles and 100 g for the baby powder. If the marbles and the baby powder are combined, the result represents a mixture of large and fine particulate matter weighing 1,000 g. Pour the mixture through the strainer and shake. What happens at this point is obvious -- the marbles are in the strainer and the baby powder is all over the floor. The baby powder was not captured by our control device -- the strainer.

Nevertheless, the collection efficiency for the mixture appears quite good at first. The strainer captured 900 grams,

or 90% of the total particulate weight. However, when each constituent -- marbles versus baby powder -- is considered separately, the collection efficiencies are very different. The removal efficiency for the marbles is 100% -- not one marble made it through the strainer. The collection efficiency for the baby powder is about 0% -- it's all on the floor. In other words, BACT for marbles is not BACT for baby powder. The same holds true for TSP and PM2.5.

The effect demonstrated in the example above is exactly analogous to what happens with a fabric filter -- we simply scaled everything up in size to make the effects visible. The control efficiencies will change based on design and materials of construction, but a fabric filter will always collect large particles more efficiently than small particles.

EPA addresses this issue in the Fine Particulate Implementation Rule as follows...

> In contrast to PM_{10}, EPA anticipates that achieving the NAAQS for $PM_{2.5}$ will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies.

72 FR 20589
Clean Air Fine Particle Implementation Rule; Final Rule

At the proposed Highwood facility, 138 tons of small particles that will escape control by the fabric filter. Nearly all of this particulate matter will be PM 2.5.

In order to reduce these substantial emissions, SME and DEQ should have considered control devices that are more effective at capturing PM2.5.

"[EPA previously] listed PM-10 and total suspended particulates as regulated forms of particulate matter and, consequently, regulated air pollutants. The EPA has recently reevaluated this finding and has concluded that its definition of regulated air pollutant under Title V applies only to emissions of PM-10."

1995 Wegman Memo (see citation above)

3. SME BACT Analysis Invalid

Putting aside the failure to conduct a BACT analysis for PM2.5, SME's analysis of BACT for PM10 was also flawed from the outset. First, it was not apparently targeted at controlling emissions of the finer particles that comprise PM10 and PM2.5. Instead, the analysis focused on

controlling all PM including the coarsest grain, TSP. However, as stated above, EPA has determined that TSP is not a regulated pollutant and not subject to BACT. It is therefore improper to include it in the analysis, and doing so skewed projections of control efficiencies to appear misleadingly high for PM10, the regulated pollutant of concern.

Second, the analysis considered filterable and condensable emissions separately. There are no regulated pollutants called “condensable particulates” or “filterable particulates”--there is only PM10 and PM2.5. The BACT analysis must be clear as to what technologies are being evaluated for these pollutants and what the control efficiencies are for each, excluding the confounding effect of TSP. If they wish to evaluate separate technologies for the filterable and condensable fractions of each pollutant, this is fine, but the final analysis must provide overall control efficiencies and emission limits for each pollutant not each fraction.

This is more than just nitpicking. When the BACT analysis is approached in this way, it is fundamentally different in terms of which control technologies are evaluated and different in terms of which will be identified as most effective. This obviously affects the economic impact and what technology is ultimately selected as BACT.

The economic feasibility of a control device is determined by the cost of the device per ton of pollutant removed ($/ton). If the regulated pollutant is broken down into many small fractions (for example condensable and filterable, or H_2SO_4, HCl, and HF) for the BACT analysis, the $/ton will increase and the device may appear to be economically infeasible.

For example, consider the following hypothetical example:

Assumptions
A source emits 300 tons per year of PM2.5
A portion of the 300 tons (20 tons) is HCl
Control equipment cost: $1,000,000

Scenario 1: Cost based on HCl alone:	$50,000/ton
Scenario 2: Cost based on total PM2.5:	$3,333/ton

One could evaluate the control device against each individual fraction of PM10 or PM2.5 (filterable, condensable, H_2SO_4, HCl, etc.) and find that in each case application of the device would not be economically feasible. Yet, when the same device is evaluated against total PM10 or PM2.5, the results show it may be quite feasible.

In some circumstances, however, application of a control technology to individual components may be more cost effective. It is important to consider both approaches in a BACT analysis involving pollutants comprised of several fractions (for example, PM2.5).

In addition to the separation of filterable and condensable PM, the SME BACT analysis also separates condensable particulate into H_2SO_4, HCl, HF, trace metals, and condensable particulate (presumably whatever is left). This is extremely confusing since all of the pollutants listed are components of CPM. We never understand how effectively PM10 and PM2.5 are being controlled as a whole. Again, as stated above, separate consideration of individual components is fine, but somewhere all the disparate data must be brought together to summarize the total control effectiveness of the regulated pollutant. Nowhere in the SME analysis is this done.

The third issue is that, MDEQ failed to address ammonia emissions in any way. With an SNCR for NOx control, there will be ammonia emissions. EPA has identified ammonia as a precursor to PM2.5. It is also an air toxic for which I expect MDEQ would want to establish an emission limit. For the HGS unit, each 1 ppm of ammonia slip equals about 5 tons per year of ammonia emissions. It is not unusual to have ammonia slip values of several ppm under normal operating conditions and much higher if the NOx control system is not well-tuned.

$$Q = \frac{2771 \text{ mmBtu}}{\text{hr}} \times \frac{9780 \text{ dscf}}{\text{mmBtu}} = \frac{27{,}100{,}380 \text{ dscf}}{\text{hr}}$$

$$C = \frac{1 \text{ ppm} \times 17.03 \text{ MW}}{10^6 \times 385.3 \text{ dscf/lb-mole}} = \frac{4.42 \times 10^{-8} \text{ lb}}{\text{dscf}}$$

$$E_{lb/hr} = Q \frac{\text{dscf}}{\text{hr}} \times C \frac{\text{lb}}{\text{dscf}} = 1.2 \frac{\text{lb}}{\text{hr}}$$

$$E_{tpy} = \frac{1.2 \text{ lb}}{\text{hr}} \times \frac{8760 \text{ hours}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lbs}} = \frac{5.3 \text{ tons}}{\text{year}}$$

Ammonia Emissions
1 ppm = 5 tons

Under the PM10 analysis, ammonium bisulfate is listed with an emission limit, but there is no data provided as to where that number came from. Further, the analysis does not address other ammonia compounds (e.g. ammonium chloride and free ammonia). If SME is making the assumption that all ammonia is bound up in sulfate

compounds before being emitted, this must be stated specifically and supported with data. Also, MDEQ should establish an ammonia slip limit to insure proper, long-term operation of the SNCR unit.

For the reasons enumerated above, MDEQ must reject the BACT analysis as not meeting regulatory requirements and not being protective of human health.

Finally, there seems to be a subtle presumption in the SME BACT analysis that as long as the NAAQS are met, the presumed BACT determination is sufficient. In fact, the BACT analysis is entirely independent of the modeling results.

EPA states:

> *The application of BACT is a specific requirement for a prevention of significant deterioration (PSD) permit that stands alone in the sense that, as a minimum, a PSD source must install BACT regardless of the air quality impact.*

EPA Memorandum, To Alabama Dept. of Environmental Management, Gary McCutchen, July 28, 1987

The modeling results cannot be used to help justify a BACT determination.

4. Consequences of Failure to Implement PM2.5 BACT

Consider the following quotation from EPA's Fine Particulate Implementation Rule:

> *The EPA established air quality standards for PM2.5 based on evidence from numerous health studies demonstrating that serious health effects are associated with exposures to elevated levels of PM2.5. Epidemiological studies have shown statistically significant correlations between elevated PM2.5 levels and premature mortality. Other important effects associated with PM2.5 exposure include aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), changes in lung function and increased respiratory symptoms, as well as new evidence for more subtle indicators of*

72 FR 20586 Clean Air Fine Particle Implementation Rule; Final Rule

> *cardiovascular health. Individuals particularly sensitive to PM2.5 exposure include older adults, people with heart and lung disease, and children.*

EPA's Clean Air Scientific Advisory Committee (CASAC) determined[8] that significant health effects from exposure to PM2.5 occur even at levels below the current NAAQS standard of 15 ug/m^3.

[8]Letter from CASAC to EPA Administrator Stephen Johnson, "Clean Air Scientific Advisory Committee Recommendations Concerning the Proposed National Ambient Air Quality Standards for Particulate Matter", March 21, 2006

According to EPA, even small increases of PM2.5 may have a substantial impact. In one EPA analysis, an increase of only 0.5 ug/m^3 PM2.5 in the ambient air could result in as many as 25-50 more premature deaths each year[9].

[9]70 FR 66006 Proposed Rule to Implement the Clean Air Fine Particle National Ambient Air Quality Standards

V. Conclusions

The MDEQ should have rejected the PM2.5 BACT analysis for all the reasons set forth above and summarized here.

1. SME did not conduct a BACT analysis of PM2.5.
2. SME did not conduct a BACT analysis of PM10 as an individual regulated pollutant.
3. There are no regulatory or technical impediments to conducting these analyses.
4. The BACT analysis submitted to MDEQ improperly included TSP, which is not a regulated pollutant.
5. The BACT analysis improperly assumed PM10 as a surrogate for PM2.5.
6. The BACT analysis addressed only separate, individual fractions of PM10 (e.g. filterable and condensable) and did not address PM10 as a whole.
7. The BACT analysis failed to address ammonia emissions.

The BACT analysis provided by SME is invalid both procedurally and technically and should be overturned. EPA has provided guidance under which this may occur:

> *Possible grounds for overturning a BACT decision include an inappropriate review (e.g., BACT*

EPA Memorandum, Huntsville Incinerator - Determining Best Available Control Technology (BACT), Gary McCutchen, April 22, 1987

procedures not correctly followed, BACT decision not correctly justified), an incomplete review, a review based on false or misleading information, or a permit which is not enforceable as a practical matter. This is not a complete list; these are just some of the most common problems.

/s/ Hal Taylor
September 10, 2007

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Technical Paper

Application of Wet Electrostatic Precipitators to Address Fine Particulate Emission Requirements from Fossil-Fueled Combustors

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BR-1762

Abstract

Application of wet electrostatic precipitators (WESPs) to boilers firing specialty fuels has been made on a limited basis over the past 30 years. However, with recent local/state requirements for new coal-fired plants using wet flue gas desulfurization (WFGD), the use of WESPs has been applied to limit total particulate emissions (including condensables and acid mist). Operating data from existing WESP installations demonstrate this technology's ability to efficiently and reliably meet these stringent performance requirements.

Discussion includes WESP history and development in this application, the generic configuration of WESPs commercially available, and various operational design philosophies that can be used. Aspects regarding installation of a WESP system for both original equipment and retrofit situations are described. Actual performance data of commercially operating WESP systems on this application are provided, as well as a discussion of future development activities that can further advance the technology.

The growing need for ultra-low total particulate emission control and associated control of fine particulate hazardous air pollutants (HAPs) and acid will provide additional application needs for WESP technology in the future.

Background

When a high-sulfur fuel is fired in a combustor, the sulfur in the fuel combines with oxygen and forms gaseous sulfur dioxide (SO_2). SO_2 can further be oxidized into sulfur trioxide (SO_3). After the air heater, the reduced temperature changes some SO_3 to acid mist that can corrode flues, air heaters, and other equipment. SO_3 forms an aerosol in a wet scrubber, which contributes to a visible, trailing plume. A wet flue gas desulfurization/scrubber (WFGD) system collects some acid mist. Acid mist can be considered $PM_{2.5}$ and may become regulated. There can be more acid mist than dry particulate in many wet scrubber stacks. Control of acid mist may be required for permits in the future. Wet electrostatic precipitators (WESPs) can be successfully applied to address fine particulate emission requirements from fossil-fuel-fired combustors.

WESPs have been commercially available since being first introduced in 1907. Wet ESPs have been used in the following industries/applications: nonferrous smelters, steel industry, spent acid plants, paper industry, incineration, and power plants burning unique fuels. However, most of their use has been in small, industrial-type settings as opposed to some of the large industrial fossil-fueled combustors and electric utility power plants. In the past 30 years, this technology has been applied periodically to these larger combustion sources firing specialty high-sulfur fuels.

In electric utility plants firing sulfur-bearing fuel, WFGD and, in the past decade, selective catalytic reduction (SCR) technologies have been added to control sulfur dioxide and nitrogen oxides (NO_x) emissions. The recent startups of new SCR systems on coal-fired power plants have demonstrated an increase of sulfuric acid emissions due to the additional oxidation of SO_2 to SO_3 across the SCR catalysts.[1] Although the control of sulfuric acid mist from electric utility sources has typically not been regulated, concerns and questions regarding these emissions are now being observed.

The combustion of petroleum coke or Orimulsion™ with relatively higher concentrations of vanadium (a catalyst for the oxidation of SO_2 produced in combustion to SO_3) produces high levels of sulfuric acid emissions, in some cases higher than power plants firing high sulfur coal.[2]

In cases where the wet FGD technology is used in conjunction with SCRs on high-sulfur coals or with high-vanadium petroleum fuels, the condensed sulfuric acid component in the flue gas can substantially exceed 20 ppmvd @ 3% O_2. This causes pronounced stack opacity because of the inherent light scattering properties of the submicron particulates.[3] Acid mist concentrations as low as 5 to 10 ppmvd have caused visible plume problems.

WESP design aspects – major types

Many hundreds of WESP installations have been serving the needs of industrial applications for nearly 100 years to control sulfuric acid and particulate emissions. Thousands of individual WESP modules are in worldwide commercial operation today.[4] There are several configurations of WESP designs now in service that are proven in commercial practice. WESP internal configurations can use either tubular or parallel-plate collecting electrodes. While the tubular WESPs will have only vertical gas flow orientation, the plate-type designs can have either horizontal gas flow or vertical gas flow orientation. The vast majority of WESP installations have used vertical gas flow regimes, as have most WESPs in North American power plant applications. Vertical flow WESPs have been as common, generally, as horizontal flow dry-type ESPs are on power plant flyash applications. Thus, three major types of WESPs among others that may someday be commercially available can be offered for consideration:

- *Vertical gas flow, stand alone*. Many times this type of system can be supplied in modular fashion and manifolded together at the site. This can facilitate construction and provide a high degree of isolation for maintenance. This type is common in industrial applications and normally carries with it a need for a dedicated space (footprint) at the plant. AES Deepwater is an example of this type of system.
- *Horizontal gas flow, stand alone*. This type has occasionally been provided to power plant or similar applications. A modular design approach can be difficult, and it generally requires its own significant footprint like the vertical stand alone. Dakota Gasification is an example of this system.
- *Vertical gas flow, integrated with wet FGD*. This makes use of the classic vertical gas flow regime that most WESPs have used over the years and provides capital and operational cost savings as well as minimal need for a dedicated footprint. The commercial units at Dalhousie and Coleson Cove Stations are examples of this system.

Considerations of major types

While any of the three basic types of WESPs can work well in fossil-fueled combustors or power plants if properly designed, the following considerations can affect the selection:

1. The historical application of vertical gas flow WESPs to acid mist collection has been both successful and preferable by users over the decades, while the use of horizontal flow WESPs has been limited in number to larger applications.

2. The high reliability of the integrated WESP approach in a utility application has been demonstrated by the Dalhousie installation. Mechanically – with no internal moving parts, reliable rigid electrodes, and properly selected materials of construction – the need for any on-line maintenance or repair is minimal. The integrated WESP provides certain advantages over either stand-alone alternative:

- Pressure drop associated with interconnecting ductwork is eliminated.
- Interconnecting ductwork, support steel, access, civil works, and balance-of-plant needs associated with a stand-alone WESP are eliminated.
- Acid collection/storage/processing is simplified (see 4, below)
- With a higher stack penetration, stack liner costs are reduced.

3. Virtually all WESPs require some sort of washing or irrigation to maintain good operation. This can come in the forms of continuous irrigation and/or periodic spray cleaning.

In an on-line horizontal WESP, wash water film on the collecting plate falls by gravity but is also pushed downstream horizontally by gas flow dynamics. This makes full plate coverage important especially at the lower, upstream corner areas. This concern is elevated as heights of collecting plate increase in large horizontal WESPs designed for a power plant's gas volume. In the integrated WESP, optimized clean water washing sprays, both co-current (bottom spraying up), and counter-current (top spraying down), ensure complete wash coverage and the wash water is delivered to and used as makeup by the WFGD below. The shorter collecting plate height of an integral WESP also further enhances cleaning efficiencies.

- To achieve adequate washing of a horizontal WESP's internals during operation, wash water quantities may need to be increased to higher levels as compared to an integrated WESP. In this case, recycling wash water may be considered. Also, capital and operating/maintenance costs for the wash recycle system must be evaluated as will the need for wash system maintenance and associated needs for outage and/or isolation. By comparison, the efficient benefits of the integrated WESP cleaning regime can minimize the daily amounts of wash water required.
- Washing techniques in a horizontal WESP need to be carefully considered to minimize electrical malfunctioning (premature sparkover) in the downstream fields, which could increase total emissions. By comparison, the collected acid and wash water in the integrated WESP is removed by a carefully designed gutter trough system to minimize potential interfield electrical disturbances during operation and washing. A final outlet mist eliminator has been incorporated to minimize total plant emissions.

4. Simplicity in the operation and greatly reduced maintenance needs of the integrated WESP are inherent, since it eliminates the piping, valves, tanks, controls, instruments, etc. associated with a stand-alone system's washing and acid handling systems. With an integrated WESP, acid is simply routed to and neutralized in the FGD limestone slurry below.

5. For retrofit at plant sites, the best selection of WESP type will likely require a specific study. Equipment costs, construction costs, space constraints, associated outage time, and operating costs must all be evaluated. For some plants, the stand-alone WESP will be indicated as the best overall approach, especially for retrofit applications.

Materials of construction

As stated earlier, WESPs have been serving the needs of the metallurgical industry and many other applications for nearly 100 years to control sulfuric acid and particulates. More than 1000 WESPs are in worldwide commercial operation today.[5] Materials of construction have most always been a major issue in WESP design for acid collection applications. In metallurgical copper roasters, for example, the SO_2 concentrations in treated gases often exceed 10% because of high pyritic content in the ore. Requirements to reduce SO_2 emissions from these sources led to the recovery of the SO_2 and conversion into a usable resource – sulfuric acid. In doing this, the WESP additionally protected the process vanadium oxidation catalyst from being "poisoned" and plugged by reducing the particulates and SO_3 prior to entering the acid conversion plant. WESPs also improved the quality of sulfuric acid by

removing trace elements, such as arsenic, chromium, lead, and others. For these reasons, the WESP became commonplace in this industry.

In the decades of the mid-1900s, the typical WESP design for acid mist control commonly used corrosion-resistant lead collection and lead-covered, high-voltage electrodes (both plate and tubes), lead-lined mild steel high-voltage support systems, and casings comprised of skeleton steel structures with lead burned over the steel skeletons for protection from the acid gas stream. Due to the physical weaknesses of the lead and the high operating and pulse pressures of downstream acid plants, leaks would often occur, and soon the underlying steel components underwent swift and severe corrosive attack and failure. Additionally, lead components were susceptible to accelerated mechanical failure when used at operational temperatures above approximately 150°F. These problems typically led to exhaustive maintenance and repair during almost every outage.

Eventually, the casing design evolved to alternatives such as fiberglass reinforced plastic (FRP) casing to house the lead and lead-covered internals. This new design improved the life cycle of the WESPs and also minimized the ongoing need for specialized lead burner craftsmen. During this same timeframe, some manufactures started using plastic and FRP collecting electrodes to further minimize the lead content of their designs. This required special design provisions to ensure the surfaces' electrical conductivity during operation. In the 1970s, some manufacturers began using specialty stainless for any lead-covered components that remained in their designs. The problems with using lead – including the specialized construction and maintenance labor required, reliability and maintenance/repair costs, and the ever growing concern over lead toxicity – forced design improvements in terms of materials of construction.

During the 1970s and 80s, the successful use of alloy throughout wet FGD systems provided sufficient confidence in the further use and applications of alloys. Today, alloy steels including 317, 6% molybdenum and C-276 grades are being used routinely in wet FGD systems. The selection of alloy materials for WESP application is site specific and is primarily a function of chloride content in the WESP section, which is, in turn, often a function of FGD mist eliminator performance, water quality, coal type, and other process factors.

What has emerged from these past applications is a strong experience base to design WESPs for high-efficiency control of sulfuric acid and particulates for electric utility applications. The base includes both horizontal flow and vertical flow WESPs. Both designs have been shown to achieve high efficiency collection. Site-specific questions regarding WESP layout and physical integration into the gas cleaning system will ultimately decide the best economic choice.

Charging and collection

A process challenge issue that surfaces during WESP operation when dealing with sulfuric acid mist is a phenomenon known as the space charge effect, or *corona suppression*. Corona suppression is a familiar factor to dry ESP process engineers and is associated principally with the presence of large amounts of ultrafine particulate. Formation of SO_3 vapor together with flue gas moisture will create a mist of sulfuric acid with submicron particle size. This mist can severely suppress operating corona current in the WESP. On an inlet WESP field, a reduction in on-line current of over 90% as compared to readings under air load may be seen. Corona suppression will result in low power and an associated decrease in collection efficiency in the WESP. Factors that promote this in a WESP following a wet FGD are large concentrations of fine sulfuric acid mist droplets and a high degree of water mist condensation.[6]

To effectively deal with anticipated corona suppression, proper and effective designs of ESP collection and discharge electrode geometries must be made. By developing an interelectrode geometry exhibiting a low corona onset voltage, and by carefully determining the optimum distance between corona electrode and collecting electrode, corona current can be established and maintained at adequate levels in the inlet fields. This reduces the fine particulate loading, and corona suppression effects to the downstream field. This permits operation with sufficient power levels in the downstream WESP fields to achieve the overall design collection efficiency. Management of corona suppression is possible due to the knowledge gained in past experiences not only with WESPs but also with dry ESPs on other applications that exhibit the corona suppression problem, such as paper mill recovery units (principally sodium sulfate salts) and dry cement kilns (where fine particulates are found in high concentrations).[7]

Pertinent WESP experience

AES Deepwater, Texas

AES Deepwater is a petroleum-coke-fired cogeneration plant located on the Houston Ship Channel in Pasadena, Texas. The plant generates approximately 155 MW of electricity.[2]

This plant utilizes a dry electrostatic precipitator to limit the levels of particulates and unburned carbon entering the limestone-based, gypsum-producing wet FGD system. This plant also uses a wet venturi scrubber prior to the wet FGD to remove additional particulate, HF and HCl. While particulate limits are necessary for regulatory compliance, control of unburned carbon is required to prevent contamination of marketable byproduct gypsum.

The petroleum coke (petcoke) fuel has a high vanadium content that results in a relatively high level of SO_3 entering the wet FGD, where the gas quenching action completes the formation of sulfuric acid mist. Only about 20 to 30% of the mist is captured in the FGD system because of the fine particle size of the mist droplets. The inlet concentration of SO_3 varies between 35 to 100 ppmvd @ 3% O_2 depending on furnace operating conditions and vanadium content in the petcoke.

AES has the oldest operating U.S. installation of a WESP in a power plant application. Table 1 shows the design information and required emission levels. The limit for total particulates including sulfuric acid and condensable was set for 0.005 grains/scfd, thus requiring a collection level of greater than 90% on sulfuric acid alone. Particulate control across the WESP is typically in the 95 to 97% range. This is in addition to the high-efficiency collection of the dry ESP and the wet venturi scrubber ahead of the wet FGD. Such high efficiency – total particulate control across the system – was necessary in 1986 to meet the stringent limits required in this nonattainment area. While the state of Texas required sulfuric acid emissions control to meet the tight particulate limits, to this day there are no federal standards for the control of sulfuric acid mist emissions from such sources.

This WESP design consists principally of a three-field upflow system of 12 parallel modules. The collection surfaces are plate type and fabricated of balsa wood coated with reinforced thermoset plastic. The plates are kept irrigated for electrical conductivity and removal of collected matter by a continuous film of water flowing down over the surfaces of the plates. A system of collection trough gutters at the bottom of the collector plates removes irrigation water and collected matter from the WESP.

Table 1
Specifications for air pollution control system installed at AES Deepwater

Dry ESP	
Inlet gas flow	634,000 ACFM at 360°F
Specific Collection Area (SCA)	376 ft^2/1000 ACFM
Part. collection efficiency	97%
FGD	
SO_2 removal efficiency	90%
Pre-scrubber/Quencher	Venturi type, downflow/co-current
Tower gas velocity	9 ft/sec
Mist eliminator	Two-stage, chevron type
Stack gas reheat	to 175F w/in-line steam reheater
Calcium sulfite oxidation	Bleedstream pressure oxidation in separate towers
Wet ESP	
Gas velocity	7.7 ft/sec
Treatment time	4.2 sec
SO_3,ppmv dry @ 3% O_2	30 to 100
Part. collection efficiency	98.9% including sulfuric acid mist
Outlet loading stopper	0.005 grains/scfd, including sulfuric acid

This WESP system has been in successful commercial operation since 1986. Particulate limits were met, and stack opacity is generally maintained well below 10%.

The discharge electrodes and other high-voltage internals were made of alloy C-276. After more than 15 years of operation, these internals appear new, with no observable signs of corrosion.

In 1999, all of the original collection plates in 1 of the 12 modules were removed and replaced with new alloy collector plates made of 6% Mo stainless steel. AES wanted access to technology with higher performance and lower maintenance costs should the need arise in the future. The discharge electrodes in this module were also changed out from the original round wires to higher corona-forming, strip-type, high-voltage discharge electrodes. Fig. 1 shows the configuration of module B that was retrofitted with alloy collector plates. Fig. 2 shows the current-voltage relationship from the inlet to outlet fields. Corona current increases significantly from the first field to the third field, which is indicative of the effective management of corona suppression, existing though not serious, because of the presence of the sulfuric acid mist fines. While collection performance of the WESP is not an issue, there is potential for an even higher corona-producing interelectrode geometry for this unit.

After more than three years of operation on this retrofitted module with all-alloy WESP collecting and discharge electrodes, the 6% Mo collector plates have shown no corrosion and still appear as they did when new. The Babcock & Wilcox Company (B&W) is currently conducting further testing on another module at this facility to develop the next generation of electrode design for optimal performance, to test innovative washing methodologies, and to gain more data on alternative materials of construction.

Northern States Power/Xcel Energy

There are 24 WESP modules installed at this plant, 12 each on the two 750-MW units. The plant chose the WESP solution to limit its stack opacity below 20%. The approach was to retrofit an upflow, two-field WESP inside an existing casing made available by repositioning the particulate scrubber internals. Following an initial trial evaluation of WESP technology, the across-the-board retrofit of WESPs began in 1998 and was completed in 2001.

Xcel Energy's Sherbourne County Station is burning subbituminous coals with about 20% CaO available in the flyash. The free CaO in this flyash acts to absorb the SO_3 in the flue gas. The original high-energy, combined particulate/SO_2 wet scrubbers alone were unable to limit stack opacity below 20%. There are no dry ESPs installed on these units. By using WESPs, the stack opacity has been limited to levels about 10% as compared to pre-WESP levels of 40%.[8] Particulate control exceeding 90% has been achieved with the 1-second residence time available within the WESPs' treatment zones.

Due to the high calcium content of the flyash, material scaling occurs in the bottom portion of the first field collector tubes. The first fields primarily capture the re-entrained droplets and carryover from the upstream scrubbers, allowing for relatively stable electrical operation in the second fields for fine particulate capture. Each of the modules gets a thorough, off-line, manual, high-pressure washdown about once a year to remove scale. In addition, part of normal daily operation includes water flushing of modules while the power supplies are de-energized. The alkaline nature of flyash and absence of sulfuric acid mist allowed the use of 304 L for the WESP internals in this application. Lessons learned from this experience are:

- A WESP is able to overcome difficult conditions for dust build-up through well scheduled wash downs.
- High-efficiency, nonacid, particulate collection, in addition to sulfuric acid mist collection, is an important capability to consider when evaluating WESPs for sulfuric acid collection.

Northwestern U.S. Petroleum Refinery

A petroleum coke calciner produces flue gas containing SO_2 that is treated with a caustic reagent scrubber. While the scrubber is highly efficient in absorbing SO_2, it cannot adequately capture the sulfuric acid mist. Since 1998, a WESP has been used to achieve a high degree of sulfuric acid capture to eliminate the visible plume. Three parallel WESP modules in a single field, upflow configura-

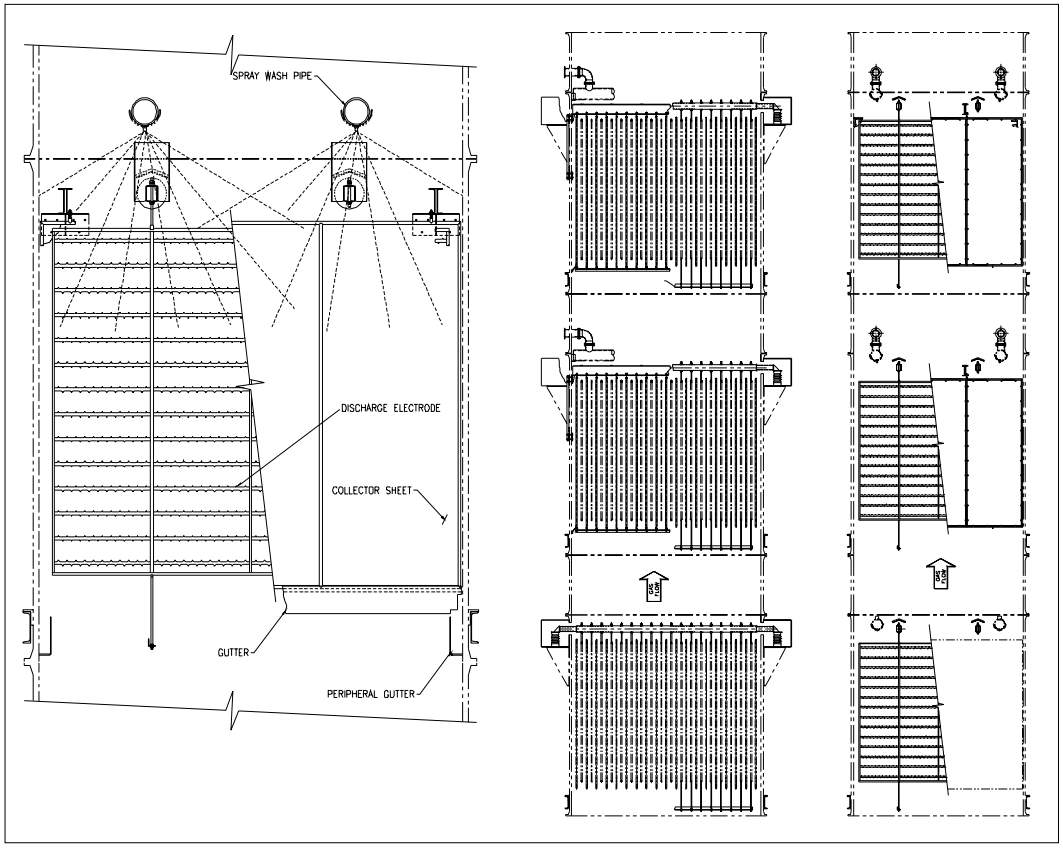

Fig. 1 Converted WESP module at AES plant.

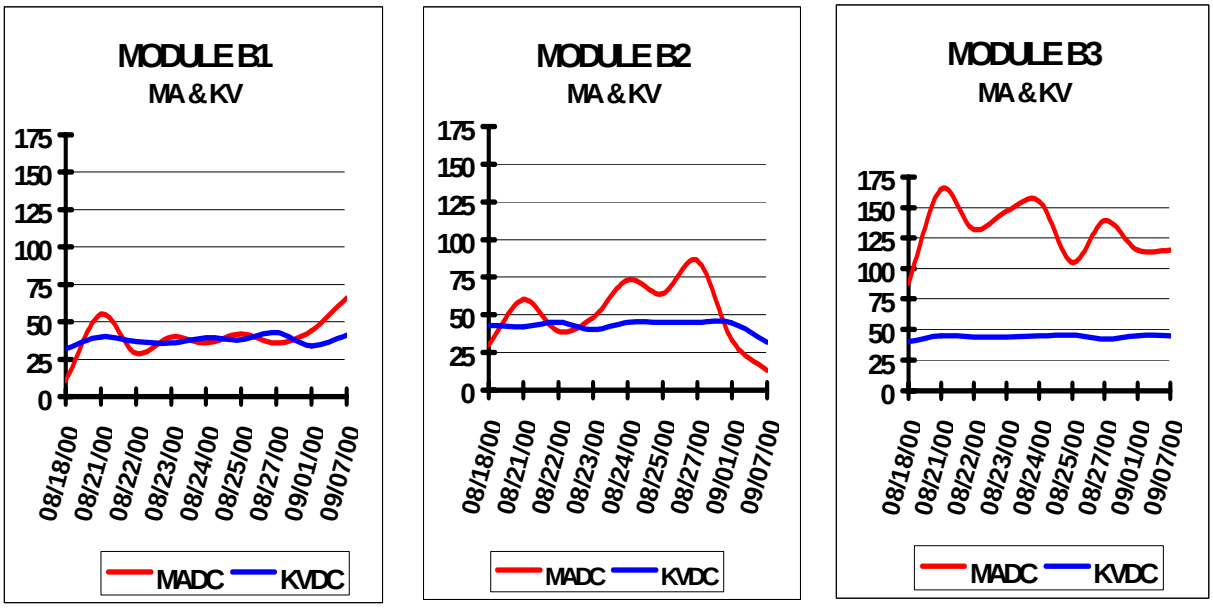

Fig. 2 I/V data form AES WESP.

tion are utilized. Figs. 3 and 4 show the excellent particulate and sulfuric acid capture across the WESP. Sulfuric mist emissions were limited to levels of approximately 1 ppmvd @ 7% O_2, and particulate concentrations were reduced to levels well below 0.005 grains/dscf.

The material of construction of these WESPs' internals and casing is alloy 904 L. The corrosion resistance has been very good, once again, observably in "like new" condition upon inspection.

New Brunswick Power, Coleson Cove

In 2002, New Brunswick Power elected to install high-efficiency WESPs following two new limestone-based, wet FGD scrubbers at its 1050-MW Coleson Cove station. This was part of a plant-wide effort to reduce the cost of electricity generation by switching to lower cost Orimulsion™ fuel while considerably reducing SO_x and particulate emissions. New Brunswick Power's decision to install the WESPs was to assure control of sulfuric acid emissions below 5 ppmvd @ 3% O_2 and to limit flyash particulates below 0.015 lb/MBtu. To achieve this level of control on sulfuric acid at all times, collection efficiency requirements will exceed 90%.

Coleson Cove will be the second power plant at which New Brunswick Power has installed a WESP system for collecting acid mist following a wet FGD. A smaller, single-field WESP system went into operation at its Dalhousie plant in the year 2000, which followed that plant's conversion to Orimulsion™ firing and wet FGD installation in 1994.

Fig. 5 shows a schematic of the layout for the Coleson Cove plant for each of the two wet FGD absorbers. It can be seen that the wet ESP consists of a three-field upflow design, similar to the design that has been in successful use for more than 15 years at the AES Deepwater facility. Scrubbed flue gas enters the inlet field of WESPs after exiting the wet FGD mist eliminator.

There are three electrical fields in series and four independently energized, high-voltage bus sections across each WESP electrical field. This conservatively sectionalized, 12-bus section design allows for small sections to be de-energized during periodic water flushings while maintaining overall emissions within design levels.

The gas exits the top of the WESP through a final mist eliminator section, which captures any re-entrained droplets that may be present during flushing cycles, and transitions directly into the stack through an outlet hood. This design simplifies and lowers the balance-of-plant costs that would otherwise be associated with a conventional arrangement where the WESP may be placed on a stand-alone basis and outside the wet FGD vessel.

The Coleson Cove plant is located on a shoreline, where layout space is at a premium. Therefore, this integrated arrangement between the wet FGD absorber and WESP made the most sense.

The material of construction of collecting plates at the inlet field is C-276. Stainless steel made of 6% Mo is used for the high-voltage systems and the balance of the collection plates.

Construction of the integrated wet FGD/WESP systems is complete. At the time of this writing, the Coleson Cove WESP was in the start-up/optimization phase of operation.

It is expected that this integrated, multipollutant approach to wet FGD installations will become more common in future fossil-fired power plants and as a retrofit where multiple control of NO_x, SO_x, mercury and fine particulates of flyash and sulfuric acid may be required.

WESP Future

The growing need for ultralow total particulate emission control and associated control of fine particulate hazardous air pollutants (HAPs) and acid mist will provide additional application needs for WESP technology in the future. Future regulation of air toxics and heavy metals and acid mist will result in the WESP playing a major role in the industrial and utility markets. The WESP is the ultimate device capable of achieving both high collection efficiency for re-

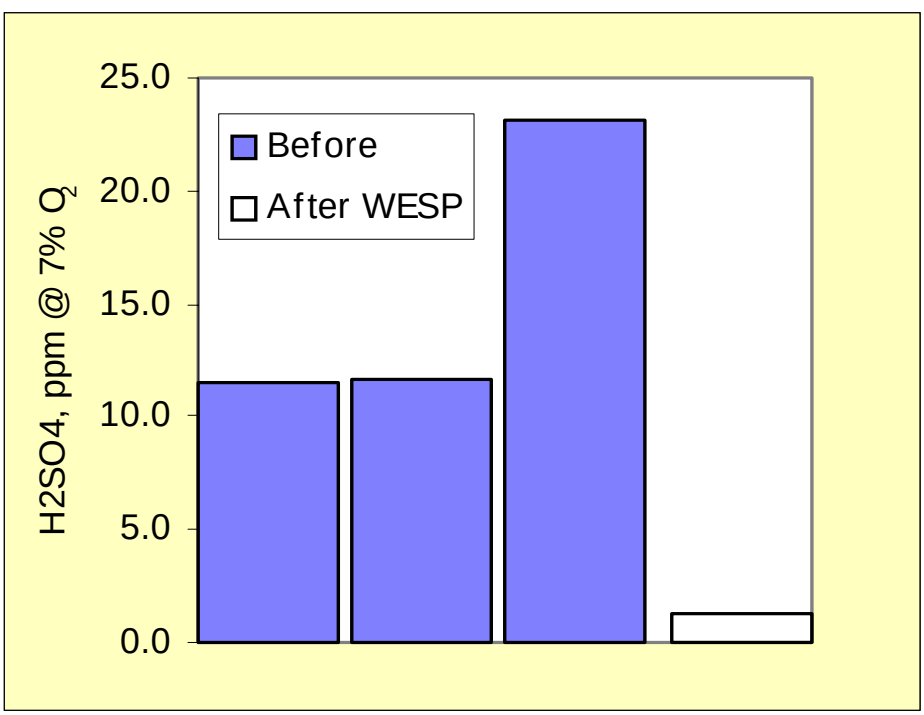

Fig. 3 WESP data on sulfuric acid from refinery in Northwest U.S.

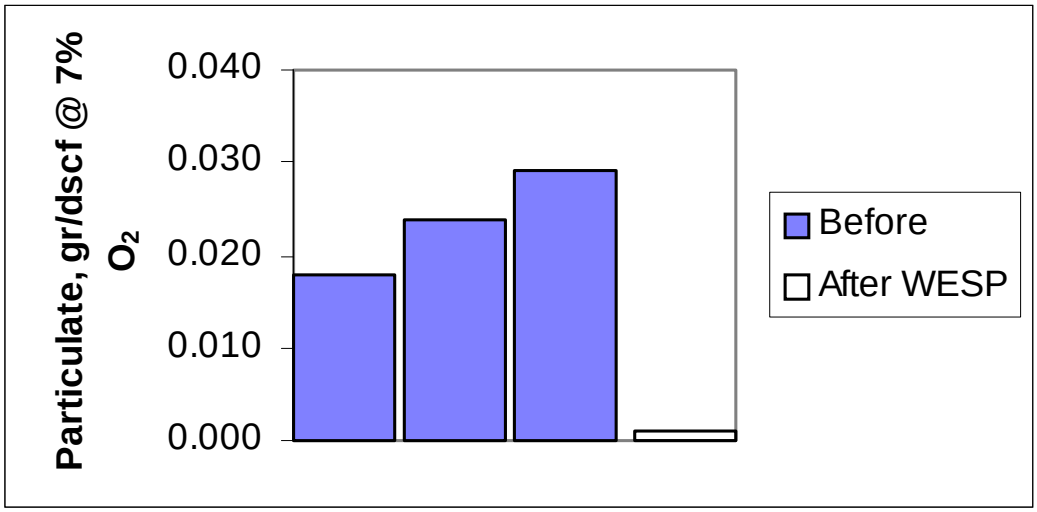

Fig. 4 WESP data on particulate from refinery in Northwest U.S.

moving the unsightly blue plume and removing ultrafine particles. Many industries are considering the WESP as the maximum achievable control technology (MACT).

Future WESP Development Needs

The prospect of future regulation of mercury and other metallic-type stack emissions from power plants will lead to comprehensive evaluations and characterizations of the effects of WESPs and other pollution control devices in collecting those pollutants from power plants. The capability of WESPs for such collection has already been shown in industrial applications.

Correlations between opacity, mass loading, and stack diameter need to be investigated so that an accurate estimate of plume opacity following a WESP in a wet stack can be accurately predicted. This will give WESP vendors more accurate data for making performance guarantees. On power plants having wet FGD and a wet stack, it has been common to measure opacity prior to the wet FGD to monitor dry particulate emissions and upstream collector (dry ESP or baghouse) performance. This practice was due to the inherent problems and limitations of optical instruments (opacity transmissometers) to reliably and accurately perform their function in the saturated gas stream of a wet stack. With the problem of visible emissions due to the formation of acid mist and the requirements for opacity guarantees based on EPA Method 9 visual methods (by human eye at a distance), previously used opacity vs. (dry) mass loading correlations can no longer be relied upon.

With the anticipated ultralow emission levels of total particulate (dry filterable plus condensable) following WESPs, classic test methodology for determining stack emissions is beginning to show an inherent lack of both precision and accuracy needed to demonstrate compliance and/or guarantee. New and improved testing methods for determining stack emissions are under development and show promise in solving this problem. As WESP technology continues to improve, such new testing methodology will also be needed to quantify the effects of these developed improvements on outlet emissions.

In general, there will undoubtedly be market pressures to lower the installed costs of WESPs for power plants and maintain or improve collection performance. Innovations and developments regarding internals, operational methods, materials and other design aspects will require the expenditure of research and development dollars by the suppliers and others to optimize the WESP in these regards for power plant application.

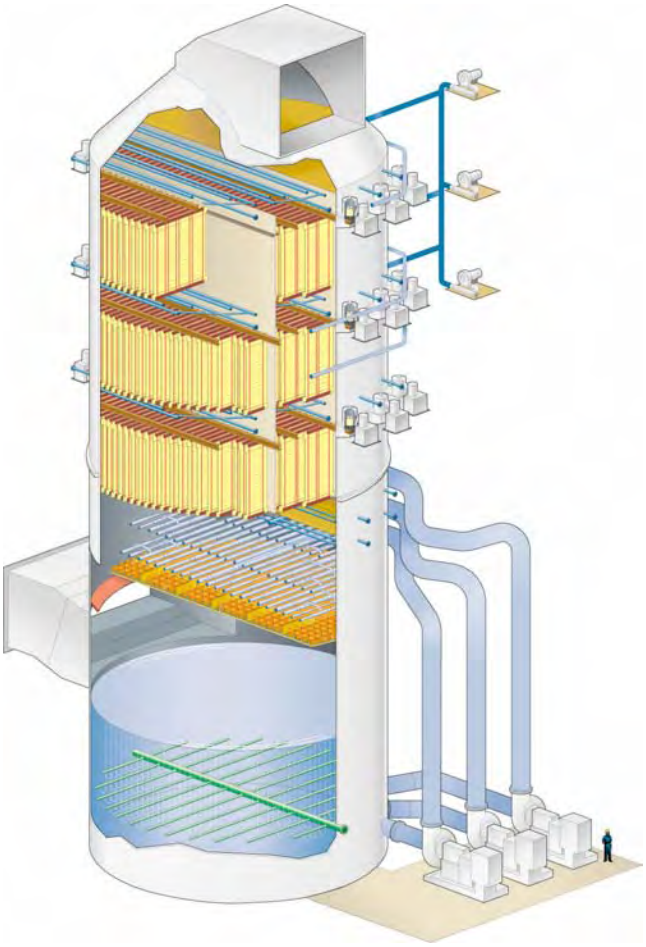

Fig. 5 Upflow WESP integrated with WFGD.

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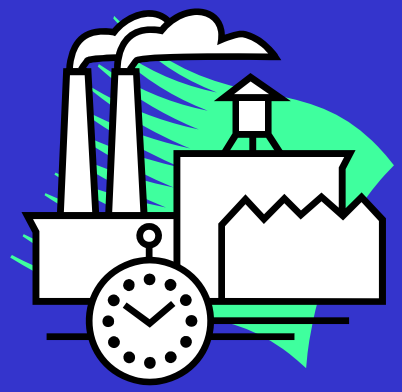
Indigo Agglomerator

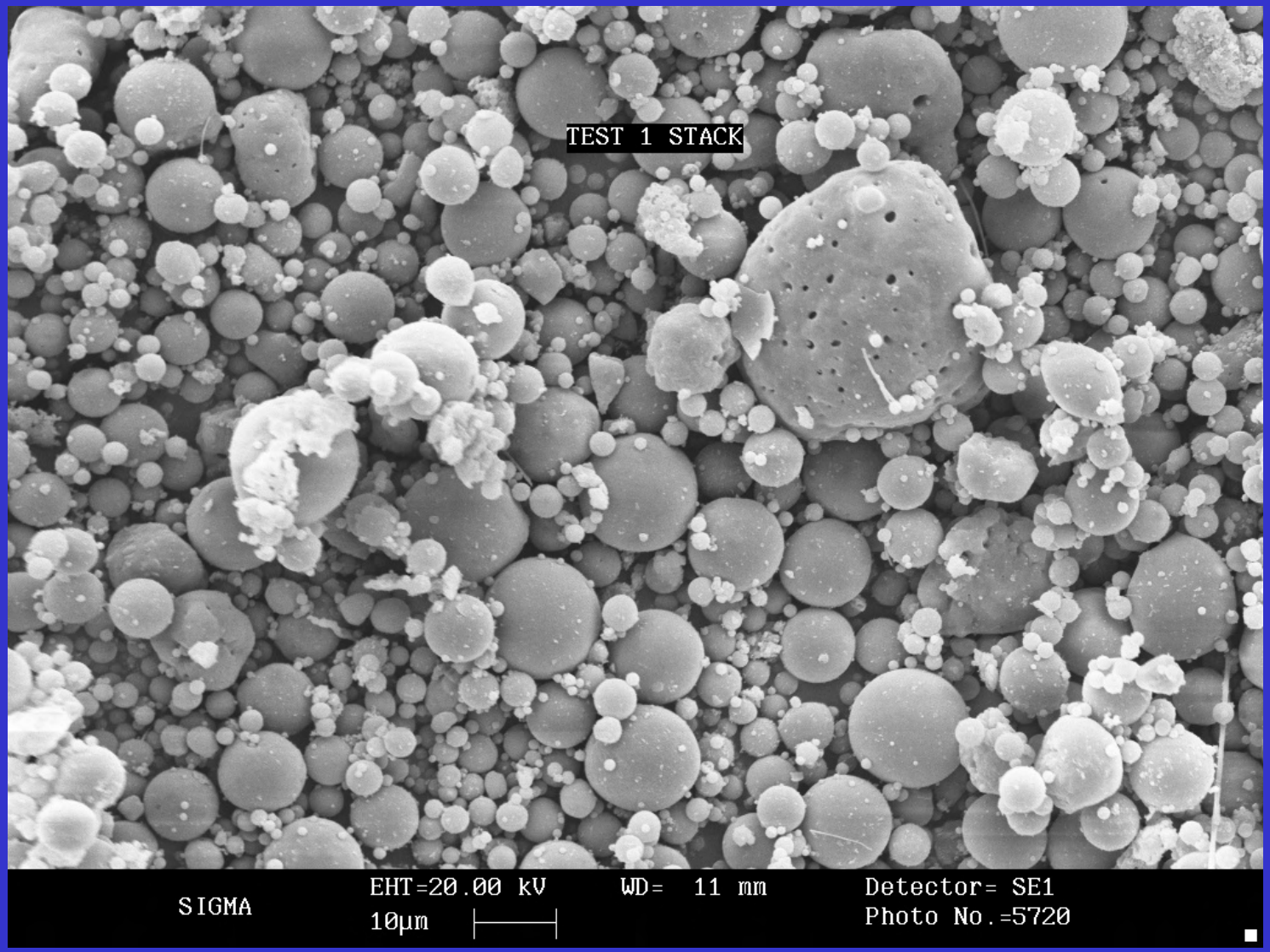


Reducing Particulate Emissions

&

Reducing Opacity

Agglomerated Particles



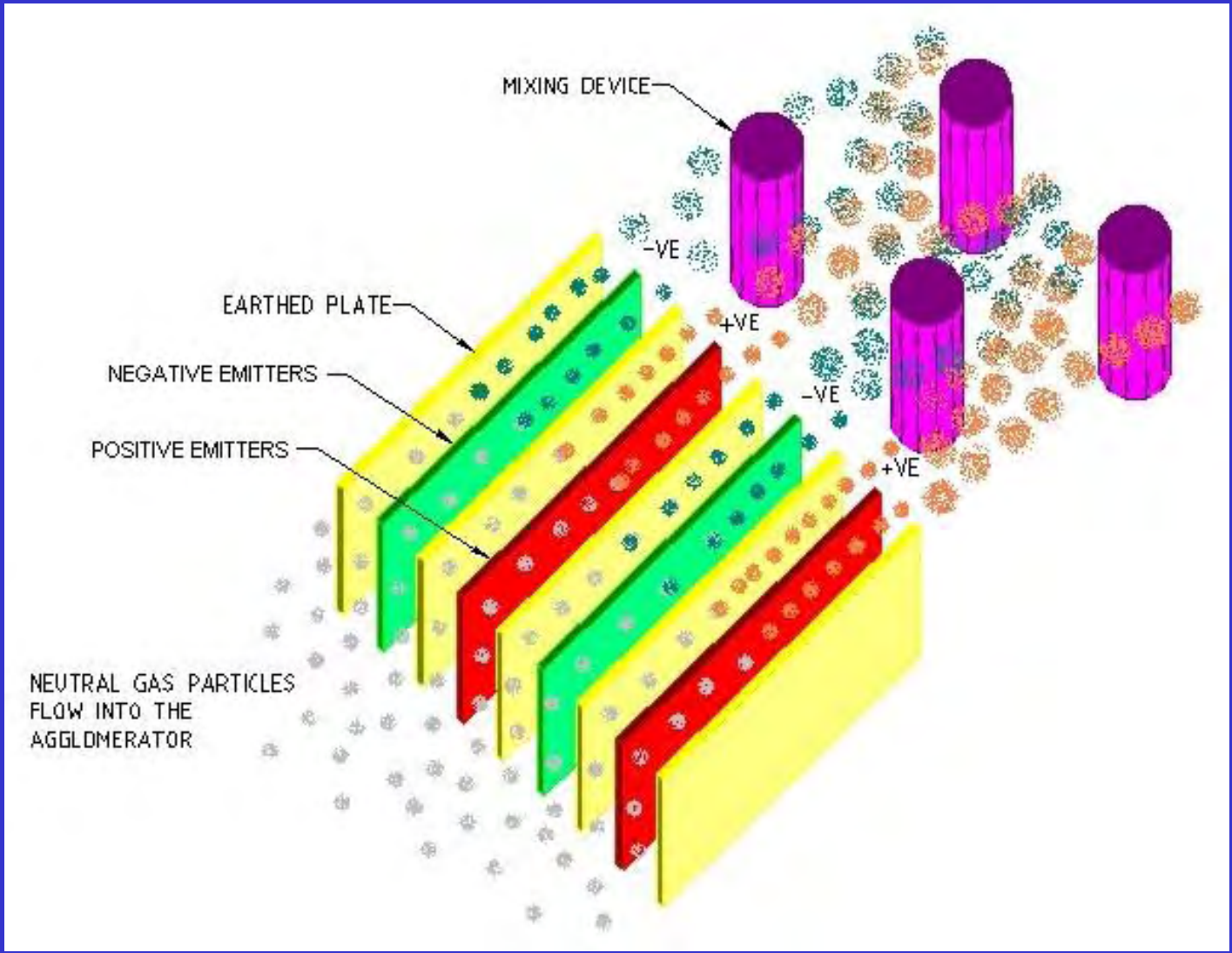
Agglomerator Is Like An ESP

- Grounded plates
- Discharge electrodes
- Alternating arrangement
- High voltage energization
- Low pressure drop

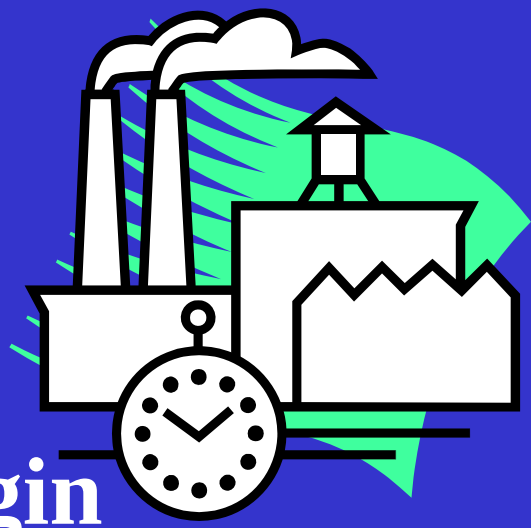
Agglomerator Is Not Like An ESP

- No collection
- No hoppers
- No rappers
- High velocity / small size
- +/- high voltage
- Low power consumption

THE INDIGO AGGLOMERATOR



THE BENEFITS

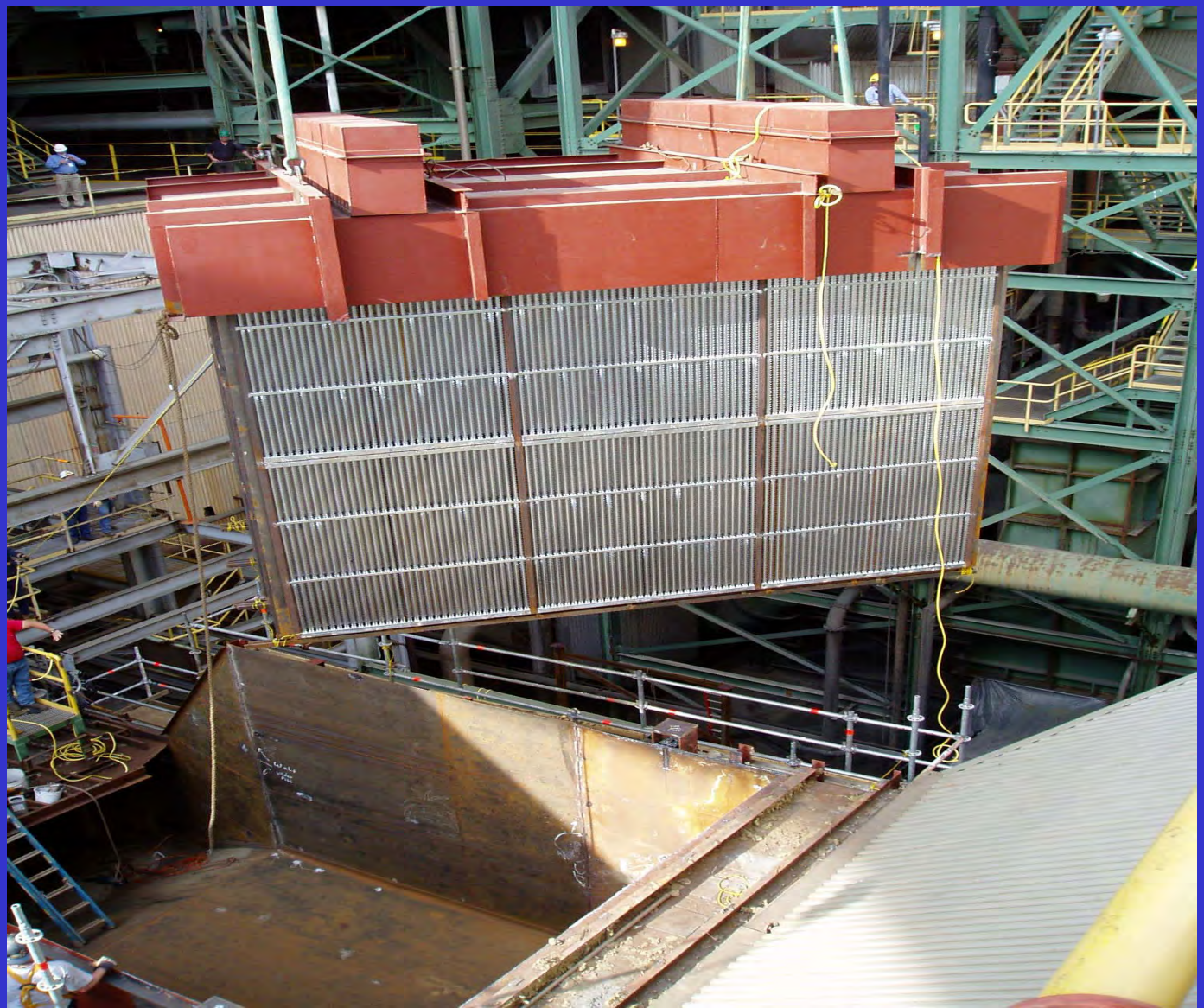


- Reduced mass emissions
- Reduced visible emissions
- Greater compliance safety margin
- Increased choice of fuel supply
- Higher tolerance for
  - Boiler upsets
  - Lost electrical sections of ESP

Tarong Power Plant -Australia

Mississippi Power
Plant Watson
Unit 4

Mississippi Power - Plant Watson Agglomerator Lift In Place



Watson ESP Outlet Tests

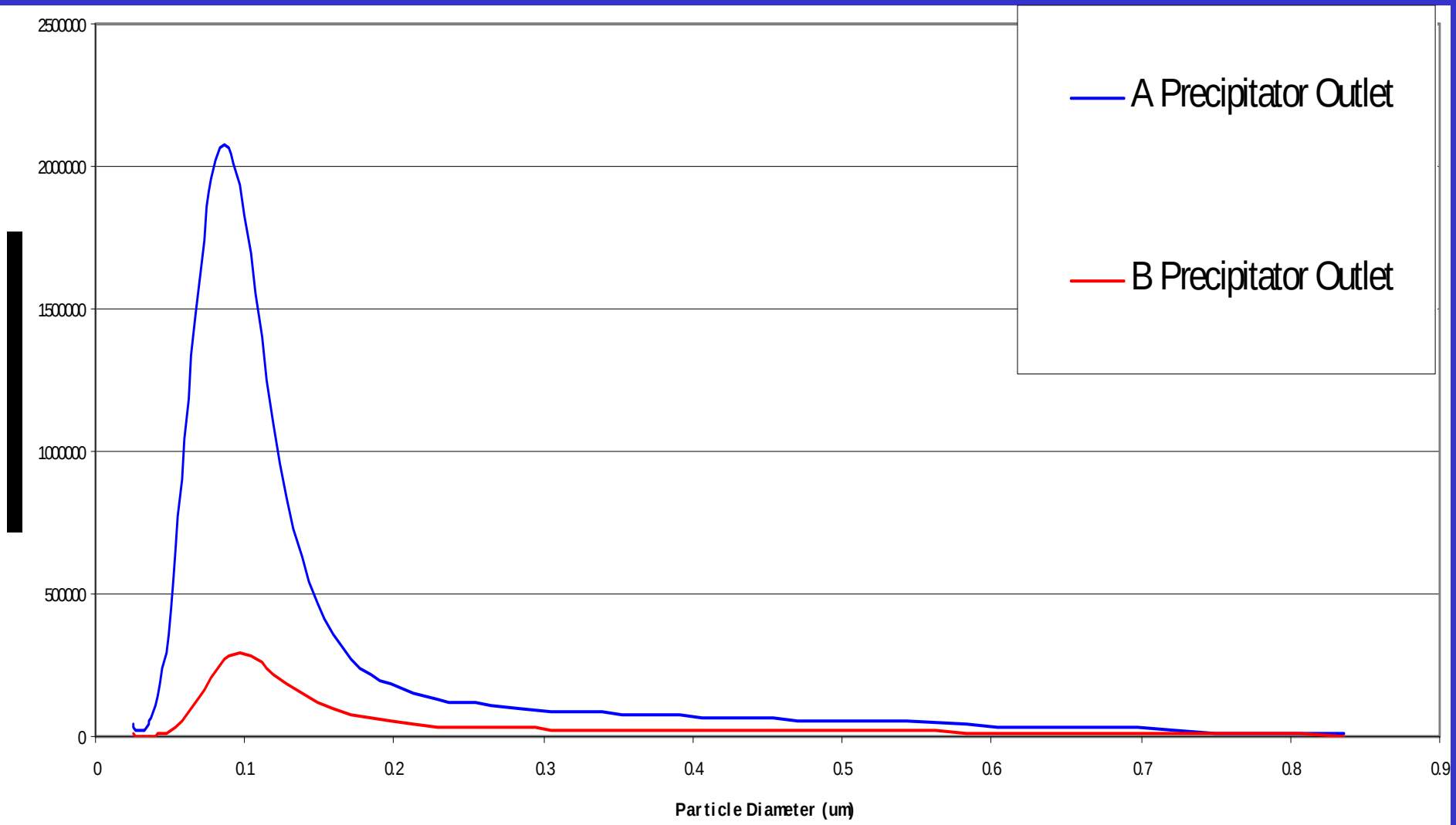
Emerald Coal April 2004

MEASUREMENT	A PASS	B PASS	REDUCTION
OPACITY %	13.2	2.3	83%
PARTICULATE			
Grains/Act. Cubic Ft.	0.0136	0.0082	40%
FLOW			
Actual Cubic Ft/Min	443 609	406 455	

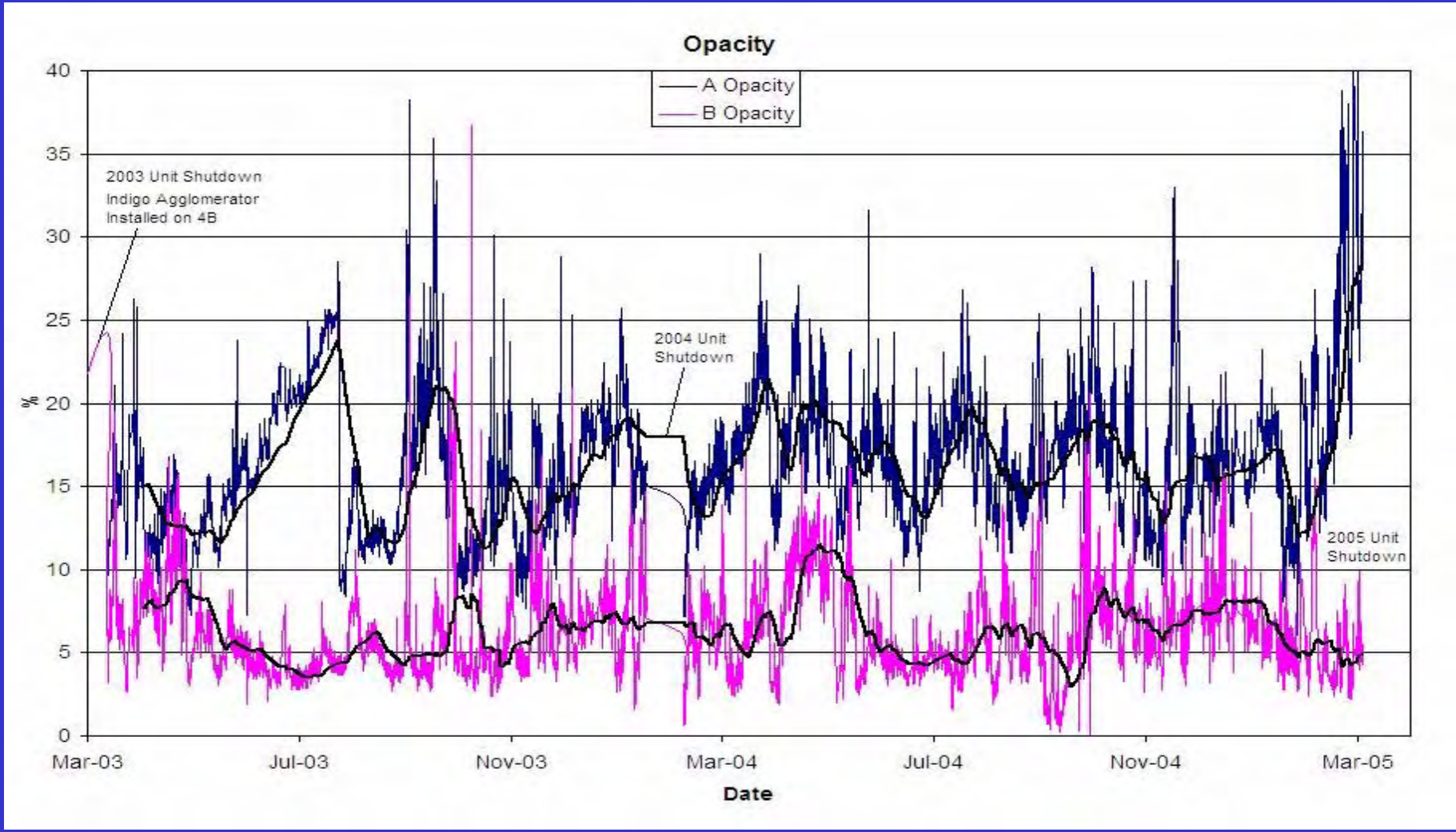
Watson ESP Outlet Tests Method 17
West Elk Coal – April 2003

MEASUREMENT	A PASS	B PASS	REDUCTION
OPACITY %	15	4	73%
PARTICULATE			
Grains/Act. Cubic Ft.	0.012	0.0066	45%
Milligrams/Cubic Meter	27.5	15.1	
FLOW			
Actual Cubic Ft/Min	408 718	450 700	
Actual Cubic Meters/Min	11 573	12 762	
GAS TEMPERATURE			
Degrees F.	276	273	
Degrees C.	136	134	

Drummond Sub Micron Particles



OPACITY TREND AT PLANT WATSON



INLET FIELD ELECTRICAL IMPROVEMENT

	A Precipitator		B Precipitator		
	Voltage (kV)	**Current (mA)**	**Voltage (kV)**	**Current (mA)**	**Percentage Increase in Current**
Before Agglomerator	52.4	217	52.6	230	**5.8%**
After Agglomerator	55.0	230	55.0	330	**43.5%**
Percentage Increase	**5.0%**	**6.0%**	**4.6%**	**43.8%**	

OUTLET FIELD ELECTRICAL IMPROVEMENT

	A Precipitator		B Precipitator		
	Voltage (kV)	**Current (mA)**	**Voltage (kV)**	**Current (mA)**	**Percentage Increase in Current**
Following Installation Agglomerator	51.6	1197	52.8	1106	**0.8%**
Before Shutdown Agglomerator	48.8	460	54.8	888	**93.0%**
Percentage Increase	**-5.4%**	**-58.1%**	**3.8%**	**-19%**	

Reducing PM 2.5 Emissions Using the Indigo Agglomerator

Paper # 49

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ABSTRACT

Fine particles, referred to as PM2.5 or particles less than 2.5 micron in diameter, are a known health hazard. The EPA estimates that the number of premature deaths could be reduced by 15,000 by reducing the amount of PM2.5 particulate in the atmosphere.[1] The Indigo Agglomerator has been installed at six power stations worldwide, providing a significant improvement in electrostatic precipitator performance that has proven consistent over time and a wide range of coals. The six power stations utilize a range of plant designs including European and American design electrostatic precipitators and various boiler combustion arrangements. The coals burned include a range of Australian, Columbian, and United States coals. This paper reports the results of tests carried out at two Southern Company and two other US utility coal fired power stations assessing the reduction of PM2.5 emissions with the Indigo Agglomerator installed ahead of existing electrostatic precipitators (ESPs). The Indigo Agglomerator uses a combination of electrostatic forces and fluidic mixing to attach the PM2.5 particulate to the coarser particulate, which is more easily collected by ESPs. Reductions of 50-70% of the 1.0 to 2.5 micron particles and reductions of greater than 90% of the 0.1 micron particles are reported in this paper. Mass emissions reductions of 30-60% and Opacity reductions of 30-60% are also reported.

HISTORY OF THE INDIGO AGGLOMERATION TECHNOLOGY

The construction and testing of a full-scale prototype of the Indigo Agglomerator started in 1999 and testing of various configurations continued through to late 2002. In mid 2002 a commercial design for the Indigo Agglomerator was developed, based on the extensive test data obtained over the previous three years. The first installation was in November 2002 at Vales Point Power Station in Australia, the site of the prototype tests.

At the invitation of the Southern Company, a second unit was installed at Plant Jack Watson in Mississippi in March, 2003. The Southern Company has carried out extensive testing over a three year period at Plant Watson while burning a wide range of coals with the Indigo Agglomerator showing a consistent improvement in electrostatic precipitator emissions.

The Southern Company placed a second order for an Indigo Agglomerator at Plant Hammond and this unit was commissioned in October 2004. Hammond was the first Indigo Agglomerator installed in a vertical duct. Both Vales Point and Watson Agglomerators were installed in horizontal gas ducts leading to the electrostatic precipitators.

The Tarong Power Station in Australia also installed an Indigo Agglomerator in 2004 with final commissioning taking place in December. The fifth Indigo Agglomerator installation was commissioned in May 2005 at the Empire District Electric Company's Asbury Station in Missouri. The sixth Agglomerator was commissioned in May 2006 on a 480 MW boiler burning 100% PRB coal. The Agglomerator is ahead of a hot side ESP.

A range of tests have been performed at each of the Southern Company installations with results that show a consistent reduction in fine particle emissions, the main contributor to visible emissions and Opacity. The independent test data shows:

- Over 90% reduction in the emissions of sub-micron particles.
- Over 80% reduction in the emissions of $PM_{2.5}$, particles less than 2.5 microns in diameter.
- A 50-85% reduction in Opacity readings, depending upon the coal and plant conditions.
- A reduction in total particulate mass (PM) emissions of between one third and two thirds, using USEPA Method 17 compliance testing.
- Extended testing at Plant Watson by the Southern Company shows that the improvements are consistent over a period in excess of three years.

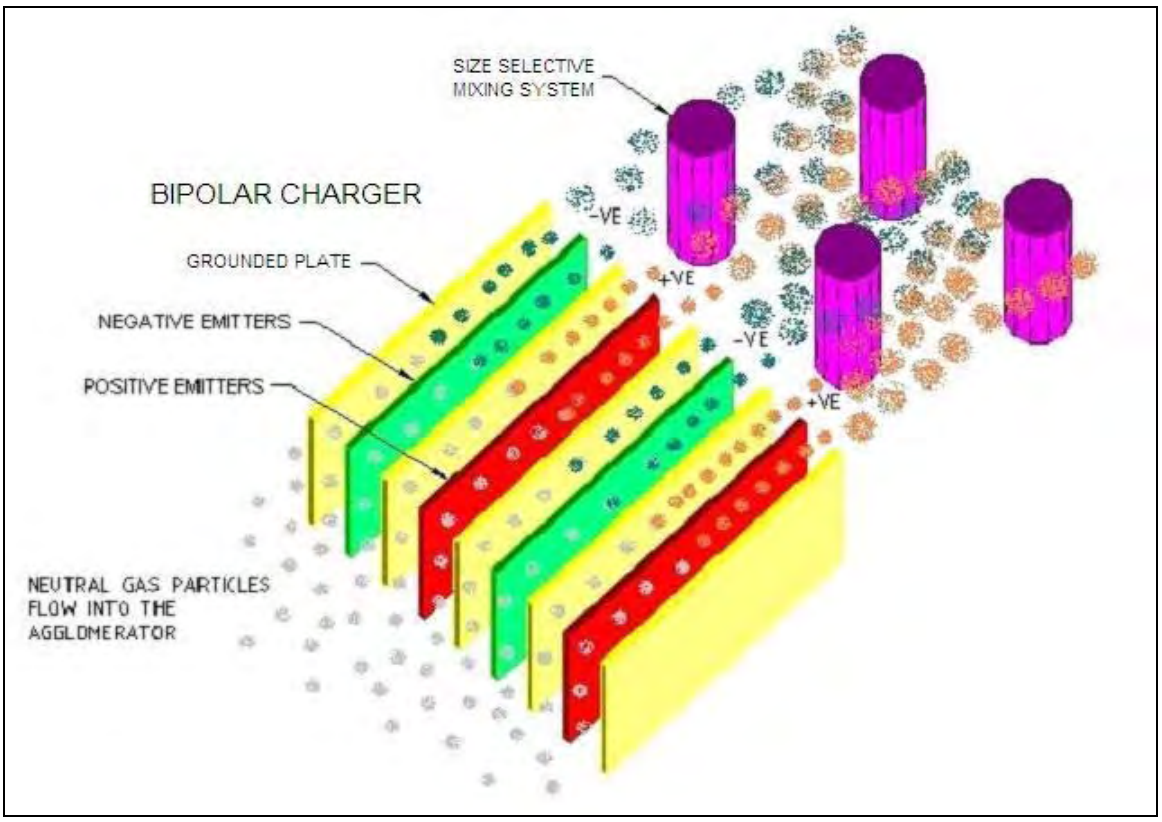
The impressive independent test results, coupled with an improvement that is consistent over both time and a range of plants burning a wide variety of coals, confirms the Indigo Agglomerator is a proven commercial option for reducing PM emissions, $PM_{2.5}$ emissions, and visible emissions (Opacity) from electrostatic precipitators.

THE INDIGO AGGLOMERATOR TECHNOLOGY

The Indigo Agglomerator utilizes two patented processes that cause the fine particles to attach to the large particles, which are easily captured by the electrostatic precipitator. The first process is the Fluidic Agglomeration Process (FAP), a physical process that occurs without the need for electrical energization. The Bi-Polar Electrostatic Agglomeration Process (BEAP) requires electrical energization to charge the particles. It is the combination of these two processes that result in the massive reduction in fine particles shown in the test data. These processes have been explained in more detail in previous papers and are not discussed here.[2]

In the Indigo Agglomerator consists of two distinctly different stages – the bi-polar charging stage and the size selective mixing stage. This can be seen in **Figure 1**.

Figure 1: Indigo Two Stage Agglomerator Design



The bi-polar charging stage charges half of the dust with a positive charge and half with a negative charge. The bi-polar charger has a series of alternating positive and negative parallel passages that the gas and dust pass through to acquire a positive or negative charge.

The second stage is a specially designed size selective mixing system (SSMS) that causes the finer positive particles to be carried by the gas and mixed with the larger negative particles emitted from the adjacent negative passage. The SSMS also causes the finer negatively charged particles to mix with the larger positive particles. Because electrostatic forces decrease rapidly with distance, the SSMS is essential to bring the finer particles close to the oppositely charged larger particles so that the electrostatic force is sufficient to cause them to attach and form agglomerates.

The Indigo Agglomerator is installed in a vertical or horizontal section of the inlet duct leading to the electrostatic precipitator and operates at a high gas velocity, generally in excess of 50 feet per second (15 meters per second). Only 20 feet (six meters) of straight duct, in either a horizontal or vertical orientation, is required to install the Agglomerator. Because of the high gas velocity, the electrodes are kept clean without any rapping, as is used in an electrostatic precipitator. This minimizes operation and maintenance costs.

The Indigo Agglomerator only uses about five kilowatts of electrical power per 100 MW of unit capacity and adds less than 0.7 inches w.g. (200 Pa) to the fan head. As a result the operating cost of the Indigo Agglomerator is very low. As a result, Indigo Agglomerator capital and operating costs are low relative to other electrostatic precipitator enhancement options. The low capital, operating, and maintenance costs make the Indigo Agglomerator very financially attractive to potential users.

INDIGO AGGLOMERATOR INSTALLATIONS

There are currently six installations of the Indigo Agglomerator, two in Australia and four in the US as shown in **Figure 2** below. Photographs of each site are shown in **Figure 3**.

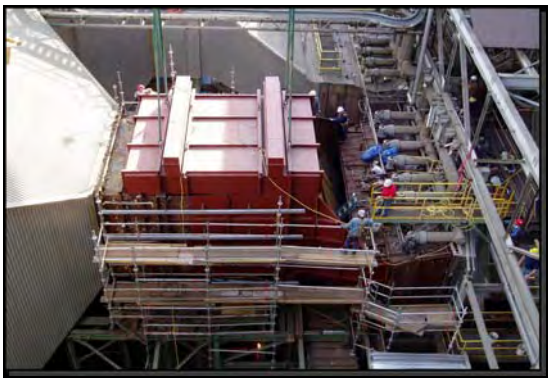
Figure 2: Indigo Agglomerator Installations

	Utility	Station & Unit	Agglom. Size (MW)	Start Up Date
AUS	Delta Electric	Vales Point Station U5	1/4 of 660	October 2002
US	Mississippi Power	Plant Watson U4	1/2 of 250	April 2003
US	Georgia Power	Plant Hammond U3	115	October 2004
AUS	Tarong Energy	Tarong Station U1	1/4 of 350	December 2004
US	Empire District	Asbury Station U1	225	May 2005
US	Dynegy Generation	Havana Station U6	480	May 2006

Figure 3: Installation Photographs

Vales Point Station

Plant Watson



Tarong Station

Asbury Station

Plant Hammond

Havana Station

In the above six installations, five are horizontal arrangements. They were preassembled on the ground and then lifted and dropped into place in the existing duct. Hammond is the only vertical arrangement. It had to be built in place. Here the internals are being installed through a slot cut in the side of the vertical duct. Although the internal support arrangement is quite different, the agglomeration technique and the agglomerator components are the same. It is expected that some future vertical designs will be preassembled, but the site limitations did not allow this type of installation at Plant Hammond.

THE US INSTALLATIONS

The Southern Company has carried out extensive long term tests at Plant Watson burning a wide range of coals including:

- Drummond is the main Columbian low sulfur bituminous coal burned at Plant Watson. It has a sulfur content of about 0.5% and an ash content of about 5% but other Columbian coals burned at Plant Watson have up to 12% ash content. SO_3 is used to condition some of these coals as the resistivity can get over 10^{12} ohm-cm. Since the installation of the Agglomerator the operation of the SO_3 Conditioning system has ceased.
- West Elk coal, from Colorado, is the main western US low Sulfur bituminous coal burned at Watson. It has an ash content of about 8% and a sulfur content of 0.6%.
- A number of eastern US medium sulfur coals have been burned at Plant Watson. These include American from the Appalachian Coal Basin, with about 1.3% sulfur and 6% ash, and Emerald from the Illinois Coal Basin, with about 2.5% sulfur and 12% ash.

Plant Hammond, another Southern Company power station, burns West Virginia bituminous coal with an ash content of about 9% and a sulfur content of 1.5%.

The site of the last Indigo Agglomerator installation, the Asbury Station, burns 85% low sulfur, sub-bituminous western US coal from the Powder River Coal Basin mixed with 15% higher sulfur eastern US coal to reduce ash resistivity. Asbury also burns 1-2% tire derived fuel.

The Indigo Agglomerator enhancement of electrostatic precipitator performance is largely independent of coal composition and properties. In particular, ash resistivity does not appear to affect the emission reduction resulting from the installation of an Indigo Agglomerator. The main impact on the improvement achieved is the amount of fine particulate produced in the boiler, which is dependent on both the coal properties and the combustion process. The higher the fine particle content in the fly ash, the better the improvement obtained from the Indigo Agglomerator. The reduction in Opacity can vary from 50% to over 90% as the fine particle component increases.

THE INDIGO AGGLOMERATOR TEST DATA

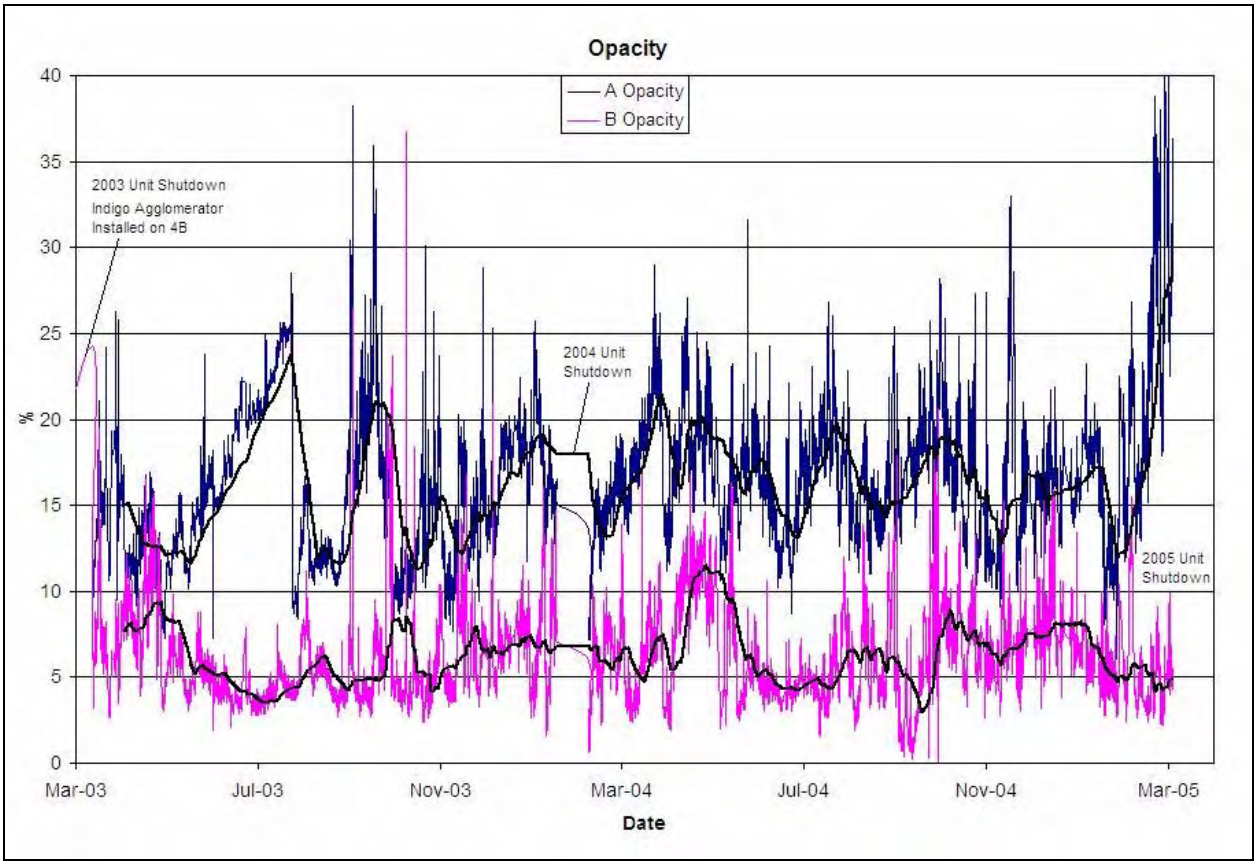
The Plant Watson Agglomerator installation, on electrostatic precipitator 4B, has had the Opacity monitored for over three years, during which time a range of coals were burned. **Figure 4** details the Opacity improvement, averaged over weeks of operation, for 4B electrostatic precipitator, with an Indigo Agglomerator, compared to the identical 4A electrostatic precipitator without an Agglomerator. A 50% improvement indicates that 4B Opacity is half that of 4A. Plant Watson monitors the coal being burned, so it was possible to determine the improvement for a number of different coals at both high and low loads. A time averaged analysis over three months prior to the Indigo Agglomerator installation showed a small bias in favor of 4B, an equivalent of 19% Opacity on 4B compared to 20% on 4A.

Figure 4: Opacity improvement with Indigo Agglomerator

Coal	Average Load (MW)	Average Opacity Improvement (%)
West Elk Coal		
High Load (>230 MW)	**245.2**	**51.2**
Low Load (<200 MW)	**169.6**	**51.2**
American Coal		
High Load (>230 MW)	**245.3**	**50.7**
Low Load (<200 MW)	**137.6**	**64.9**
Emerald Coal		
High Load (>230 MW)	**245.7**	**78.3**
Low Load (<200 MW)	**139.9**	**88.4**
Drummond Coal		
High Load (>230 MW)	**245.6**	**60.2**
Low Load (<200 MW)	**142.5**	**68.7**

Plant Watson Unit #4 is base loaded, so it operates at close to full load for all but a few hours each day. By removing data at loads below 245 MW the Opacity trend at full load for the full two years of operation can be trended. This trend is given in **Figure 5**, which shows clearly that 4B electrostatic precipitator emissions consistently less than half that of 4A.

Figure 5: Plant Watson Two Year Opacity Trend at Full Load



A number of mass emission tests using the USEPA Method 17 have been performed at Plant Watson and Plant Hammond. **Figure 6** contains the data for the three tests carried out at Plant Watson including two sets of tests burning West Elk Coal performed one year apart. This shows a consistent improvement in mass emissions on electrostatic precipitator 4B, with the Indigo Agglomerator, compared to the unmodified 4A.

Figure 6: Plant Watson Method 17 Mass Emission Test Data

	West Elk Coal Test Date 4/17/03			West Elk Coal Test date 4/1/04			Emerald Coal Test date 4/13/04		
Measurement	**A Pass**	**B Pass**	**B Pass Reduction Compared to A Pass**	**A Pass**	**B Pass**	**B Pass Reduction Compared to A Pass**	**A Pass**	**B Pass**	**B Pass Reduction Compared to A Pass**
Opacity %	15	4	**73.3%**	20.2	7.25	**64.1%**	13.25	2.3	**82.6%**
Mass Emission									
Grains/Act Cubic Ft.	0.012	0.0066	**45.0%**	0.02369	0.0159	**32.9%**	0.0137	0.0082	**40.1%**
Milligrams/Cubic Meter	27.5	15.1	**45.1%**	54.3	36.3	**33.1%**	31.3	18.8	**39.9%**
Pounds/Million BTU	0.0382	0.0231	**39.5%**	0.0735	0.0475	**35.4%**	0.045	0.026	**42.2%**
Gas Flow									
Actual Cubic Ft/Min	408,718	450,700	-10.3%	433,093	395,412	8.7%	443,609	406,455	8.4%
Actual Cubic M/Min	11,575	12,764	-10.3%	12,265	11,198	8.7%	12,563	11,511	8.4%
Gas Temperature									
Degrees F.	276	273	1.1%	280	264	5.7%	269	260.5	3.2%
Degrees C.	135	134	0.7%	138	129	6.5%	132	127	3.8%

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Figure 7 contains similar data for Plant Hammond. Because the Indigo Agglomerator was installed on both electrostatic precipitator inlets, it was necessary to compare the performance of Unit 3, with the Indigo Agglomerator installed, to an identical unit, Unit 2. Both of these units share a common Stack where the Method 17 tests were performed on consecutive days. On the first day Unit 2 was operated at full load for the test, with Unit 3 shut down, and on the second day Unit 3 was operated at full load with Unit 2 shut down. The willingness to accept the significant cost of taking generating units off-line to allow testing of the Indigo Agglomerator is an indication of the great interest that the Southern Company has in using the Indigo Agglomerator technology at other plants.

Figure 7: Plant Hammond Method 17 Mass Emission Tests.

Measurement	Unit 2 11/20/04	Unit 3 11/21/04	Unit 3 Reduction Compared to Unit 2
Mass Emission			
Grains/Act Cubic Ft.	0.0038	0.0015	**60.5%**
Milligrams/Cubic Meter	8.7	3.4	**60.5%**
Pounds/Million BTU	0.0124	0.0049	**60.5%**
Gas Flow			
Actual Cubic Ft/Min	540,064	489,363	9.4%
Actual Cubic M/Min	15,295	13,859	9.4%
Gas Temperature			
Degrees F.	264.8	253.8	4.1%
Degrees C.	129.3	123.2	4.7%

Particle size tests were also performed at both Watson and Hammond using a unique laser particle size analyzer by Process Metrix, Model PCSV-P. This device measures particle count concentration, rather than particle mass, and operates most effectively in the range of 0.3 to 50 um. The PCSV-P instrument uses a laser based single particle count process for in-situ particle size measurement across an aperture in a water cooled probe, which is inserted into the gas stream to eliminate extraction problems encountered with other particle size analyzers. Sub-micron particle tests were also carried out by the Southern Research Institute using a TSI Model 371A SMPS Analyzer, which uses electrostatic mobility to measure particle distribution from 0.02um to 0.9um. This unit uses an extraction system that removes the larger particles. Although there is only a small overlap in the size of particles analyzed by the two very different processes, there was a good correlation in this region.

Figure 8 shows a typical West Elk Coal size distribution using the Process Metrix Analyzer and **Figure 9** shows this data in terms of Slip, the percentage of particles that are not collected, and outlet emission reduction compared to 4A electrostatic precipitator, which does not have an Indigo Agglomerator. **Figures 10 and 11** show similar data for the Emerald Coal and **Figures 12 and 13** show the same information for the sub-micron data obtained using the TSI Analyzer while burning Drummond Coal. **Figure 14** shows combined particle slip and improvement over a broader range of particle sizes.

Points of note include:

- The particle size distribution at 4A and 4B air heater outlet is almost identical, validating the electrostatic precipitator Opacity and Mass Emission comparisons.

- Emissions reductions, due to the Indigo Agglomerator installation, increase with reducing particle size from about 60% at 10um to over 90% below 0.1um.

- The emission reduction in the particle size range that is most visible and has the most impact on Opacity is about 80%.

Figure 8: West Elk Coal Particle Size Distribution Using Process Metrix Analyzer

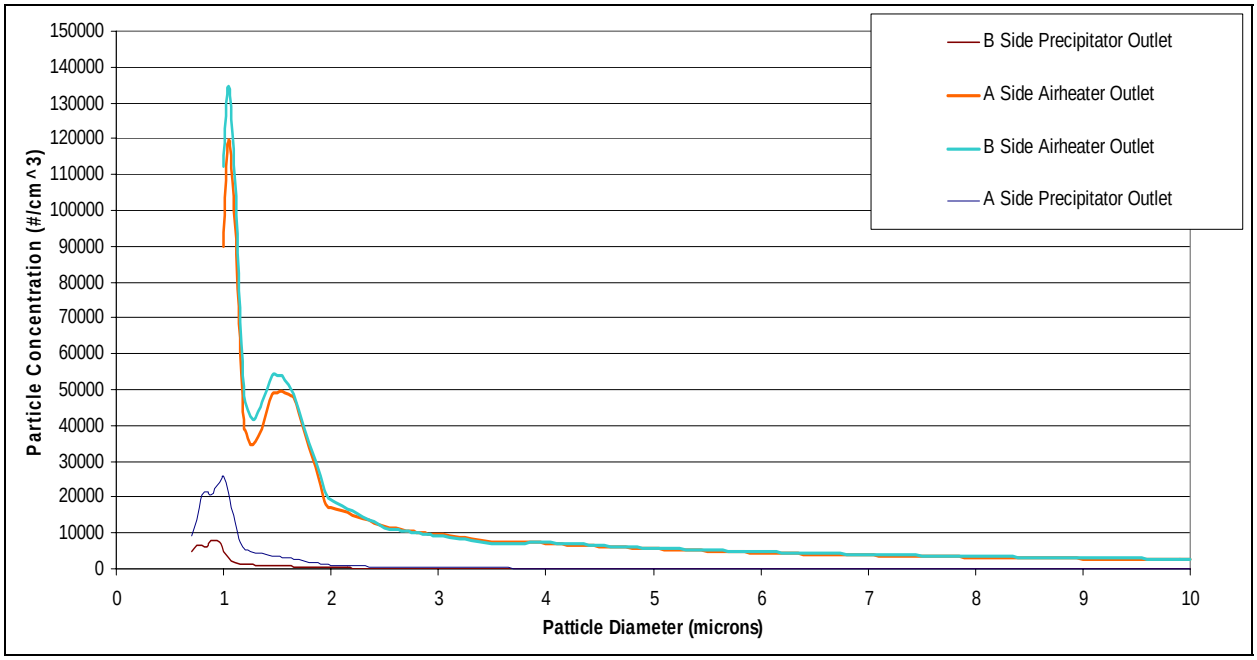


Figure 9: West Elk Coal Slip and Emission Reduction vs. Particle Size

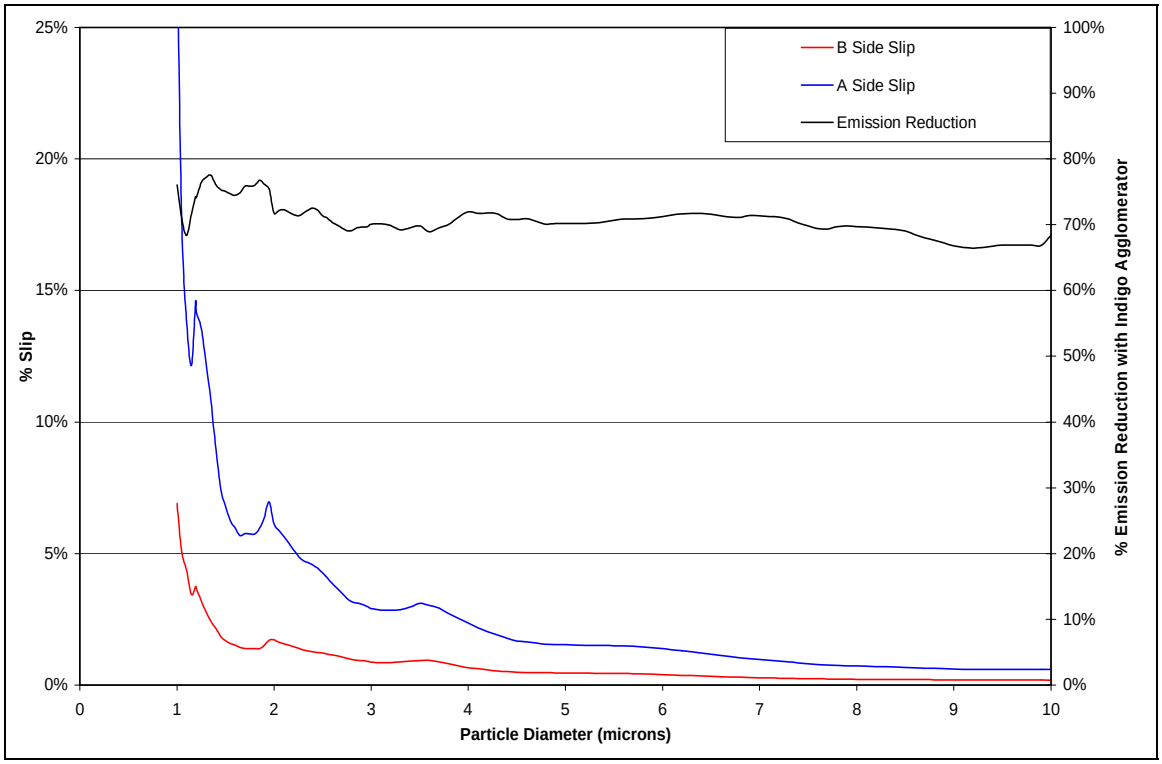


Figure 10: Emerald Coal Particle Size Distribution

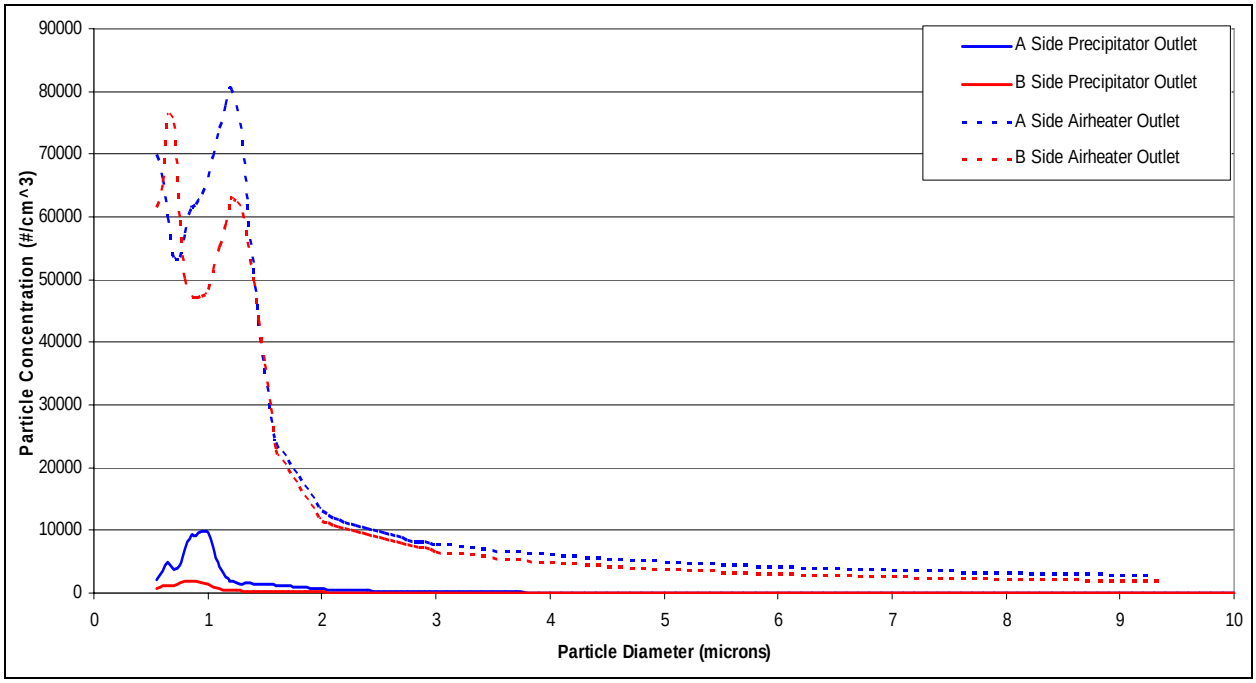


Figure 11: Emerald Coal Ash Slip and Emission Reduction vs. Particle Size

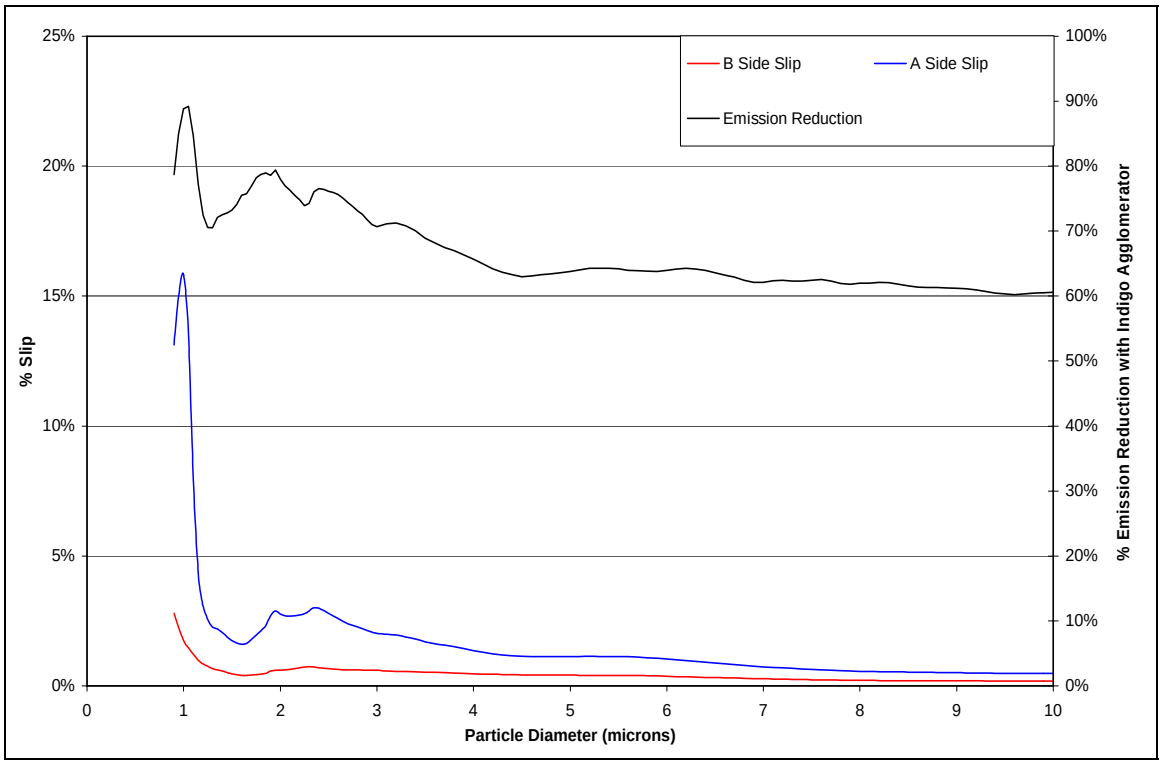


Figure 12: Drummond Coal Sub-micron Particle Size Distribution

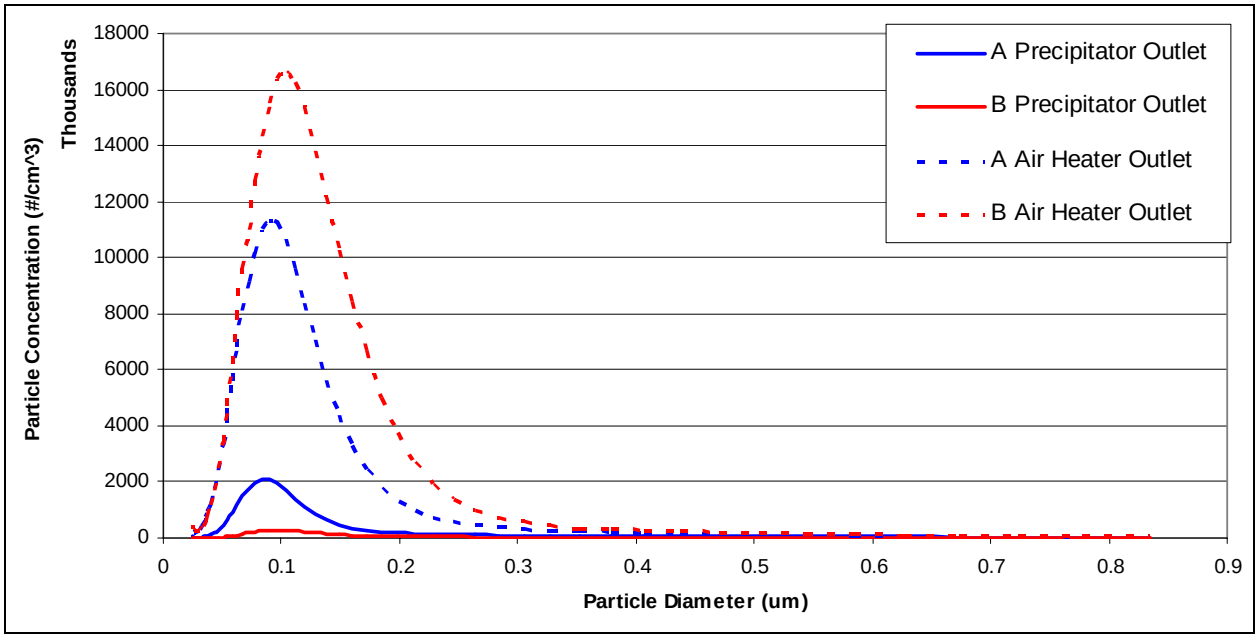


Figure 13: Drummond Coal Sub-micron Slip and Emission Reduction vs. Particle Size

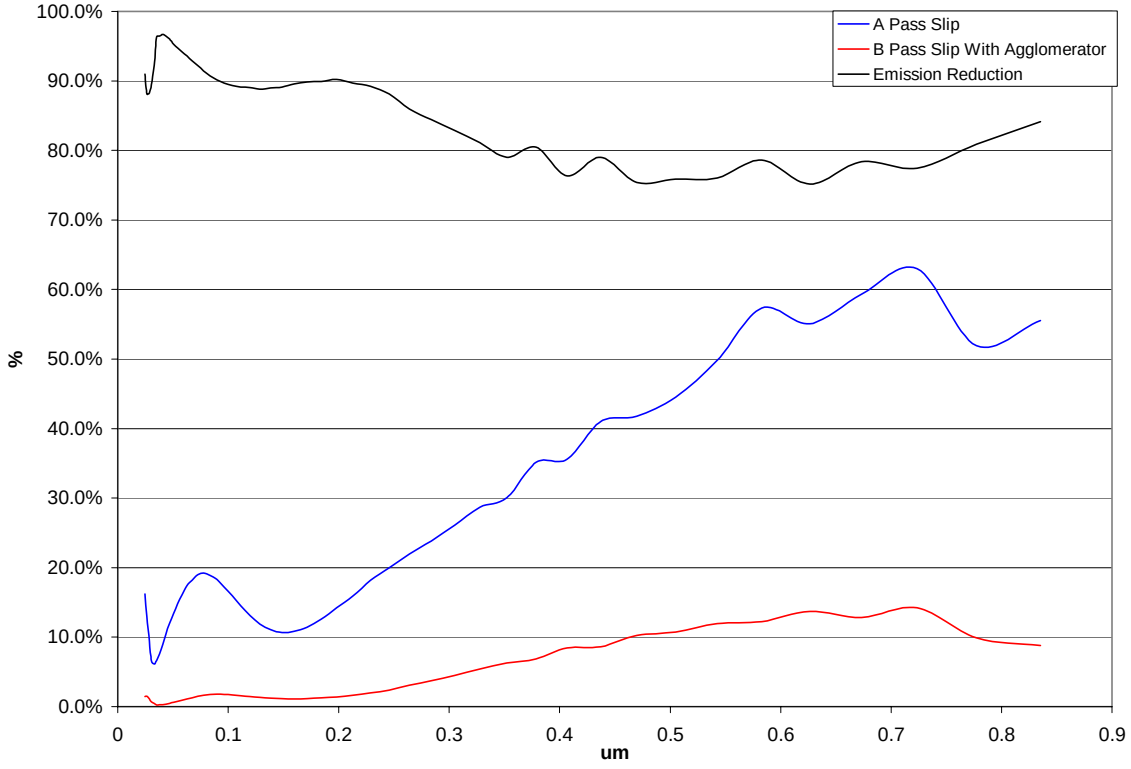
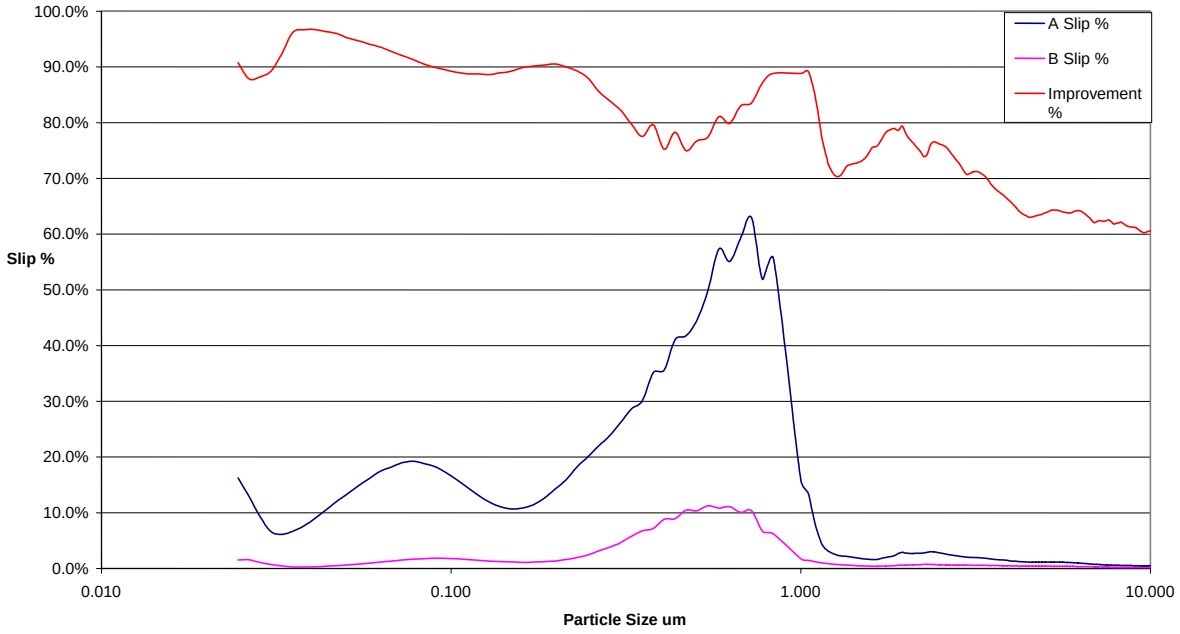


Figure 14: Combined Particle Slip and Improvement



AGGLOMERATOR PERFORMANCE AT ASBURY

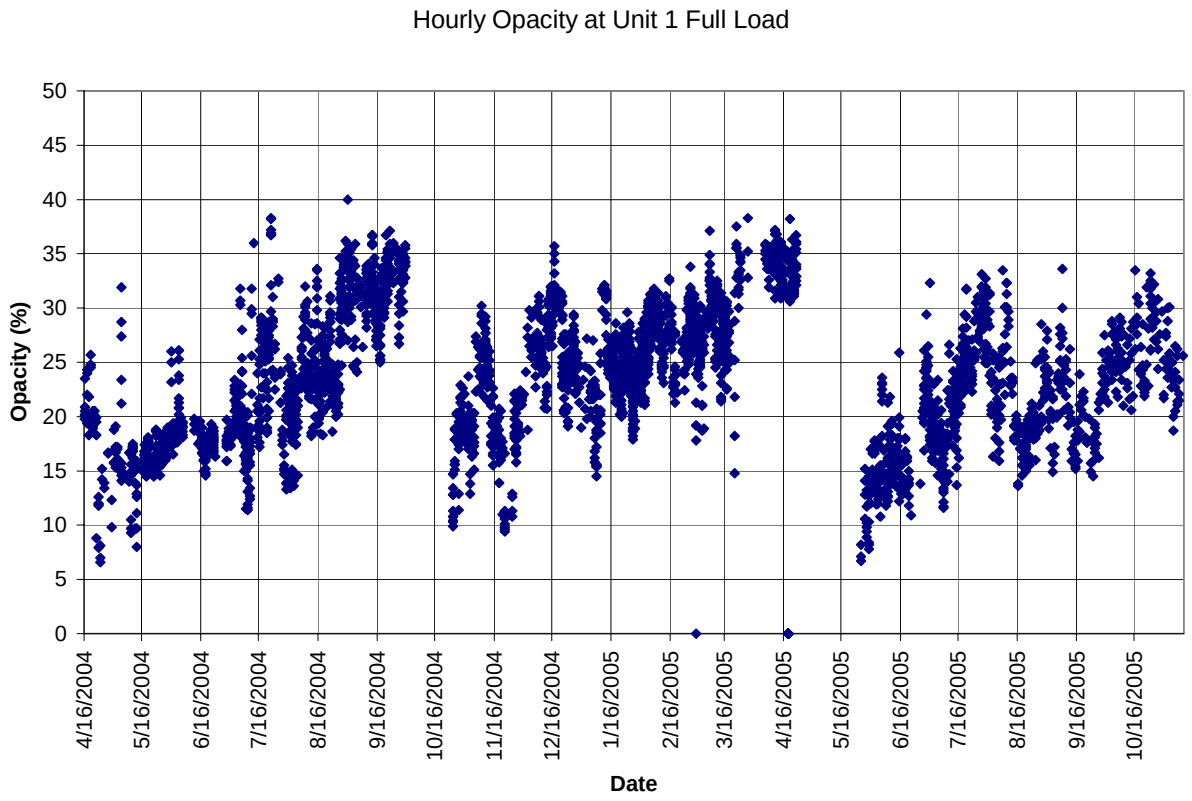
At the time of the writing of this paper, neither mass emissions nor particle size testing had been done at Asbury. Since this was a full installation on both ESP inlet ducts, no side by side comparison could be made. Additional ESP sectionalization and power supplies were also completed at the time of the Agglomerator installation, so it is impossible to separate the contributions of the Agglomerator and the sectionalization, when comparing the performance before and after the installation.

During the hot summer of 2005, Asbury operated at loads of 205 to 225 MW most of the time. Opacity varied from the high teens to the low 30s depending on coal burned and operating conditions. This fluctuation in opacity could not give definitive proof of enhancement by the Agglomerators and the new power supplies. However, only a small derate was required for a period of about 2 hours for an unknown reason. This derate did not occur until November after six months of continuous run. Asbury set a new plant record of 193 days of continuous operation during the 2005 campaign. This compares quite favorably with operation the previous summer, when derates of 5 to 15 MW occurred on Unit 1 for over 130 hours during a much cooler summer.

The hourly opacity at full load is given below in **Figure 15** for the period of April 2004 through November 2005. The boiler and ESP cleaning outage in September 2004 and unit outage in May 2005 when the Agglomerators were installed are evident in the gaps of data in the figure. As discussed above, variations in coal, boiler operation, flue gas temperatures, and ESP operation/performance all make it difficult to assess the performance of the Agglomerators. The Agglomerators cannot compensate for the deterioration in performance in the downstream ESPs due to these variations.

However, the opacity reductions following the Agglomerator installation in May 2005 are evident in the graph. In the two previous cycles after boiler and ESP cleaning, full load opacity was below 10%, but as the boiler and ESPs got dirty, the opacity peaked at nearly 40%. Following the installation of the Agglomerators, the opacity increased as in the previous 2 cycles, but seems to be consistently lower over the following 6 months of operation.

Figure 15: Asbury Opacity Before and After Agglomerator Installation (Agglomerator Commissioned May 2005)



Agglomerator Installation at Havana Station

Dynegy Midwest Generation's Havana Unit #6 Agglomerators were commission in May 2006. Unit #6 is a 480MW boiler burning 100% PRB coal. There are two large parallel hot side ESPs ahead of SCR (selective catalytic reduction) systems for NOx control. Hot side ESPs are well known to be problematic. With PRB coal ash, ESPs suffer from "sodium depletion", which results in deterioration in ESP efficiency with time. Poorly performing hot side ESPs may require boiler derates to maintain compliance and may require frequent shut downs for cleaning to regain higher efficiency.

The design of the Agglomerators at Havana is quite different from other installations. Due to rather high flue gas velocities, the Agglomerators had to be longer to achieve required treatment times. Due to the high flue gas temperatures and the need to design for reduced steel strength at these elevated temperatures, the Agglomerators had to be design in 2 series sections. The Havana Station photograph in **Figure 3** shows the outlet sections of each duct already installed and an inlet section being lifted into place.

At the writing of this paper, mass emissions and particle size test data were not available. The test results for Havana Station will be the subject of a future paper.

CONCLUSION

The Indigo Agglomerator was designed to reduce fine particle emissions from coal combustion sources that use ESPs for particulate control. The Agglomerator uses electrostatic forces and fluidic mixing to agglomerate the finer particles to the larger particles. There are six Indigo Bi-Polar Agglomerator installations in operation at this time, with a sixth just completing commissioning at the writing of this paper. The older two have been in operation for over three years.

This paper has discussed the Indigo Agglomeration technology, described the six installations, and presented various test results from the US installations. The Indigo Agglomerator technology is simple in its design and implementation, and yet has produced dramatic reductions in mass emissions and opacity. Test results show mass emissions reductions of 30% to 60%. Opacity reductions were 50% to 85%. Fine particle measurements confirm the agglomeration of the fines by the Indigo Agglomerator with PM2.5 emissions reductions of 50-90%.

The large reduction in fine particle emissions cannot account for the large corresponding decreases in mass emissions. In previous papers on the Indigo Agglomerator it was shown that the reduction in fine particles results in higher ESP corona power, which ultimately improves overall ESP efficiency for all particle sizes. Fine particles in the flue gas tend to quench the corona current and reduce ESP overall efficiency. Fine particle removal by agglomeration increases overall ESP efficiency.

Although the Agglomerator was initially designed for use ahead of existing ESPs, it has the potential to enhance fabric filter operation as well. It is the fine particles that penetrate into the fabric, causing high pressure loss. This high pressure loss generally means higher intensity and more frequent bag cleaning. This ultimately leads to shorter bag life. The Indigo Agglomerator should be able to reduce operating and maintenance costs of a fabric filter.

At the writing of this paper Southern Company had just conducted mercury removal testing at Plant Watson. It is postulated that the fluidic mixing of the Agglomerator will enhance mercury removal by the inherent carbon of the LOI and by injected activated carbon. This subject is left for future papers.

REFERENCES

1. Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper, US Environmental Protection Agency, June 2005.

2. Truce, Rodney J., et.al., “Enhanced Fine Particle Collection Using the Indigo Agglomerator”, ICESPX (10th International Conference on Electrostatic Precipitation) Proceedings, Cairns, Australia, June 25-29, 2006.

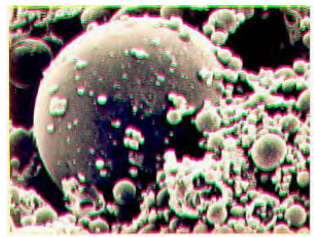
Wheelabrator
Air Pollution Control Inc.
A Siemens Company

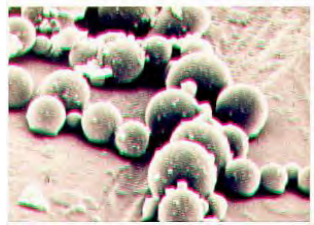
PM2.5 Control with Wet Electrostatic Precipitators (WESP)

November 2, 2006

EPA PM2.5 Standards

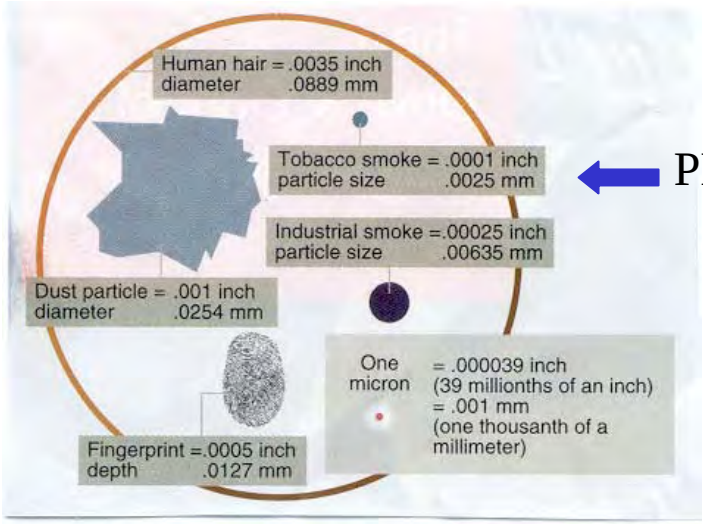
- Filterable Particulate
  - <2.5 microns in size
  - Exists as solid particulate at temperatures of 250ºF or higher
  - Collected in "front-half" filter of PM test apparatus
  - Represents ~ 25% of PM2.5 emitted by sources





- Condensable Particulate
  - <2.5 microns in size
  - Vapors that condense at ambient temperatures
    - SO_3 – H_2SO_4 sulfuric acid mist
    - Toxic metals – cadmium, chromium, lead, magnesium
  - Collected in "back-half" impingers of PM test apparatus
  - Represents ~ 75% of PM2.5 emitted by sources
  - Has not been required to date to meet PM10 standards

Relative Particle Size



PM2.5

LOWER LIMIT OF VISIBILITY (NAKED EYE) ……. 40 MICRONS

WHITE BLOOD CELLS …….….. 25 MICRONS

RED BLOOD CELLS ……. 8 MICRONS

BACTERIA (COCCI) ……. 2 MICRONS

SULFURIC ACID MIST …… 0.3 MICRONS

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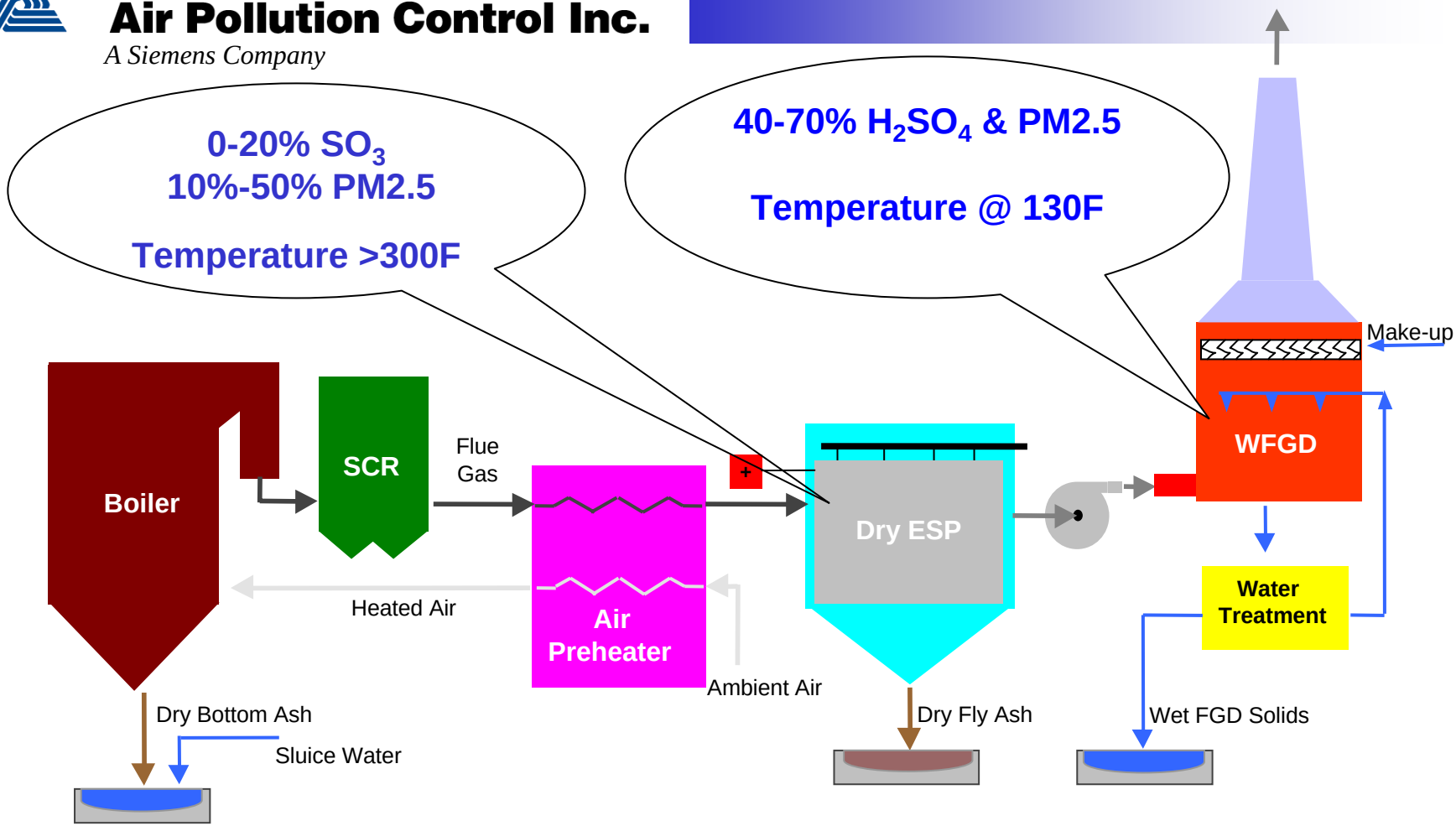
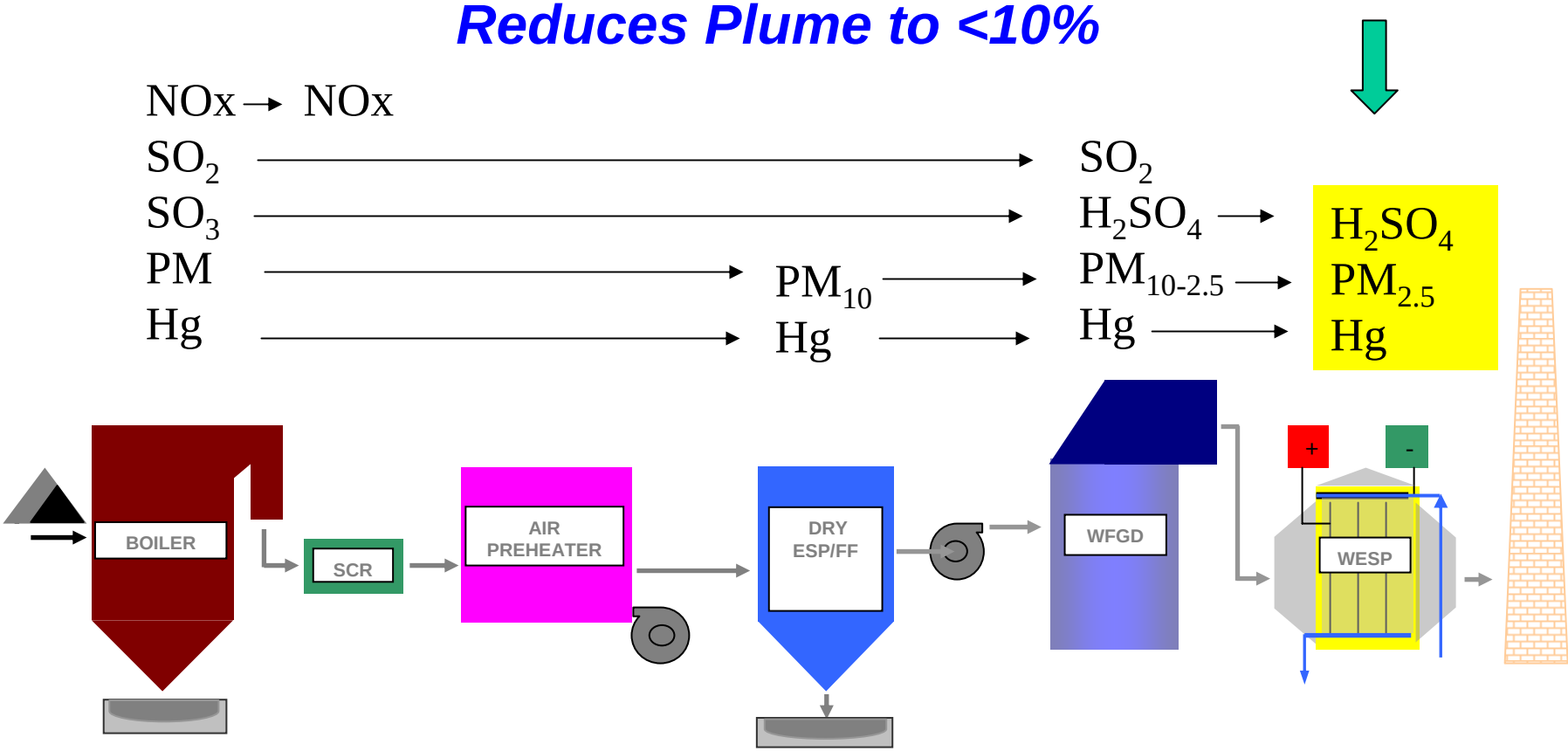


Blue Plume After Dry ESP & Wet FGD

The WESP Controls SO3 + PM2.5 + Hg

Reduces Plume to <10%



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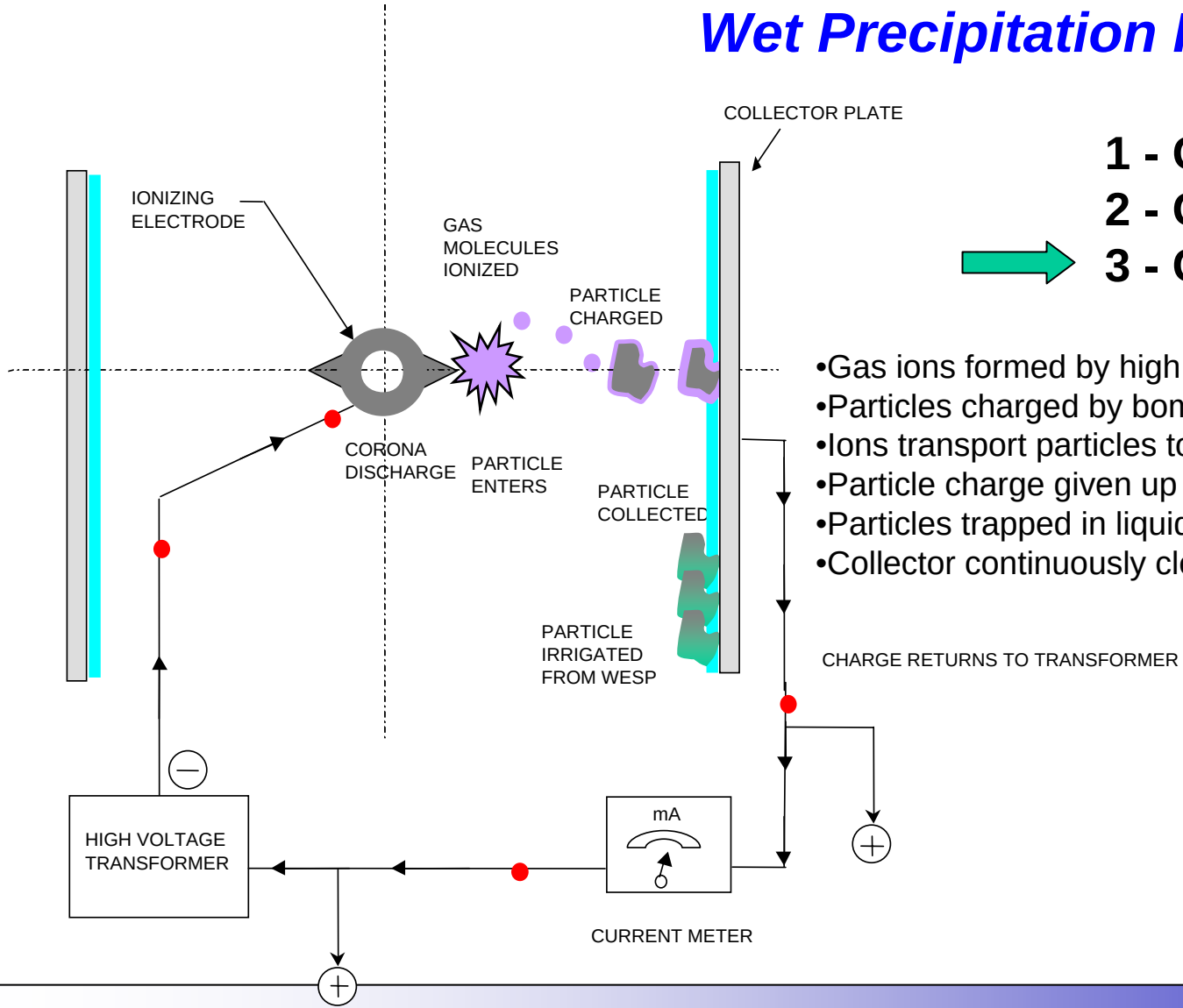
Wet Precipitation Process



1 - Charging
2 - Collection
3 - Cleaning

- Gas ions formed by high voltage corona discharge
- Particles charged by bombardment of gaseous ions
- Ions transport particles to collector
- Particle charge given up to collector
- Particles trapped in liquid film
- Collector continuously cleaned

New Coal-Fired Power Plant APC Configurations

– Active Projects – Proposed Projects

Facility	Unit Size (MW)	Coal Proposed to be Fired	APC Control Technology
Elm Road	2 x 615	Pittsburgh #8	FF / WFGD / WESP
CWLP - Dallman Unit 4	200	Blend of Bituminous and Sub-bituminous	FF / WFGD / WESP
Trimble County Unit 2	750	Blend of Bituminous and Sub-bituminous	ESP / FF / WFGD / WESP
Thoroughbred	2 x 750	Western Kentucky Bituminous	ESP / WFGD / WESP
Prairie States	2 x 750	Southern Illinois Bituminous	ESP / WFGD / WESP
Longview Power	600	2.5% Sulfur West Virginia Bituminous	DSI / FF / WFGD

Why Wet ESP?

- Multi-Pollutant Control
  - PM2.5
  - SO3
  - Metals
  - Mercury
- Opacity Reduction
  - <10% visible plume
- Operationally
  - Low Pressure Drop
  - No Moving Parts
  - Self-Cleaning
  - Small Footprint
  - Flexible to Upset Conditions
  - No Impact on Upstream Equipment
- Fuel Flexibility
  - Switch to Lower Cost, Higher Sulfur Coal

A Final Polishing Device

FRSID	Utility Name	Plant Name	Plant Location State	Plant Location County	Boiler ID	Pollutant Tested	Test Date	Original Test Result	Original Test Result Units
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	Pb	3/1/2004	0.00268	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM10	3/1/2006	0.003	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	FL	3/6/2003	0.00005	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	CO	2/28/2006	0.022	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	CO	2/22/2005	0.023	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	2/20/2007	0.013	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM10	2/21/2007	0.005	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	VOC	2/28/2006	0.0024	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	3/4/2003	0.003	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	3/4/2003	0.002	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	3/4/2003	0.003	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	2/22/2005	0.01	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	3/1/2004	0.005	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM	2/28/2006	0.005	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	FL	2/21/2007	0.000059	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	FL	2/20/2007	0.00006	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM10	3/5/2003	0.011	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM10	3/5/2003	0.011	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM10	2/23/2005	0.007	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM10	3/3/2004	0.014	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	CO	3/4/2003	0.063	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	CO	2/20/2007	0.013	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	CO	12/7/2007	0.0158	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	FL	2/22/2007	0.00007	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	Mercury Com	3/4/2004	0.00116	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM	3/5/2003	0.011	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM	2/23/2005	0.016	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM	3/3/2004	0.015	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM	3/1/2006	0.003	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	PM	2/21/2007	0.008	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	CO	3/5/2003	0.03	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	CO	2/23/2005	0.032	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	CO	3/3/2004	0.032	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	CO	2/21/2007	0.013	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	CO	12/6/2007	0.0215	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	Pb	3/3/2004	0.00847	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	Beryllium Cor	3/1/2004	0.000043	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	FL	3/6/2003	0.00008	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM10	3/4/2003	0.002	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM10	2/22/2005	0.01	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM10	3/1/2004	0.007	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM10	2/28/2006	0.005	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	PM10	2/20/2007	0.013	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	VOC	2/28/2006	0.0023	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	Mercury Com	3/1/2004	0.00148	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	3/6/2003	0.004	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	3/6/2003	0.004	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	2/25/2005	0.004	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	2/28/2005	0.003	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	3/4/2004	0.005	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	3/2/2006	0.007	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM10	2/22/2007	0.01	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	CO	3/6/2003	0.051	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	CO	2/24/2005	0.027	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	CO	2/25/2005	0.027	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	CO	3/4/2004	0.024	lbs/mmbtu

FRSID	Utility Name	Plant Name	Plant Location State	Plant Location County	Boiler ID	Pollutant Tested	Test Date	Original Test Result	Original Test Result Units
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	PM	2/22/2007	0.011	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	SAM	3/7/2003	0.000036	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBC	Pb	3/4/2004	0.00179	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	FL	3/4/2003	0.000138	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBA	FL	3/4/2003	0.000138	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	FL	3/5/2003	0.000145	lbs/mmbtu
110000362018	Operating Servi	Cedar Bay Gene	FL	Duval	CBB	FL	3/5/2003	0.00016	lbs/mmbtu

Commonwealth of Kentucky

Natural Resources and Environmental Protection Cabinet
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601
(502) 573-3382

Title V
AIR QUALITY PERMIT
Issued under 401 KAR 52:020

Permittee Name:	Thoroughbred Generating Company, LLC
Mailing Address:	701 Market Street, 6th Floor, St. Louis, MO 63101
Source Name:	Thoroughbred Generating Station
Mailing Address:	P.O. Box 151, Central City, KY 42330
Source Location:	Thoroughbred Generating Station 1380 Thoroughbred Drive, Central City, KY 42330
Permit Number:	V-02-001 Revision 2
Log Number:	53619
SIC Code:	4911
Review Type:	Title V/PSD
Source ID #:	21-177-00077
Oris Code:	55462
Region:	Owensboro
County:	Muhlenberg
Application Complete Date:	April 23, 2001
Issuance Date:	October 11, 2002
Revision 1:	December 6, 2002
Revision 2:	February 17, 2005
Expiration Date:	October 11, 2007

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John S. Lyons, Director
Division for Air Quality

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SECTION A – PERMIT AUTHORIZATION

Pursuant to a duly submitted application, the Kentucky Division for Air Quality hereby authorizes the construction and operation of the processing and air pollution control equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any emissions units without having first submitted a complete application to the permitting authority and received a permit for the planned activity, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet or any other federal, state, or local agency.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 01 and 02 Pulverized Coal Fired Steam Electric Generating Units (SGU001 & SGU002)

Description:

Pulverized Coal Fired Boilers, equipped with Selective Catalytic Reduction (SCR); Electrostatic Precipitator (ESP); Wet Flue Gas Desulfurization (FGD); and Wet Electrostatic Precipitator (WESP)
Number two low sulfur (0.05% sulfur) fuel oil or natural gas used for startup and stabilization
Nominal rating 7,443 mmBtu/hour each
Construction Commence Date: Estimated 2002

Applicable Regulations:
401 KAR 59:016, New electric utility steam generating units.
401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of performance for electric utility steam generating units applicable to an emission unit with a capacity of more than 250 mmBTU per hour and commenced on or after September 19, 1978.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances
40 CFR 63, Subpart B, National Emission Standards for Hazardous Air Pollutants
40 CFR 60, Appendix F, Quality Assurance Procedures
40 CFR 64, Compliance Assurance Monitoring
40 CFR Part 75, Continuous Emission Monitoring

Compliance with 40 CFR 75, Continuous Emissions Monitoring, shall constitute compliance with the monitoring and quality assurance requirements of 401 KAR 59:016 and 40 CFR 60, Appendix F.

1. Operating Limitations:
   a) Pursuant to 40 CFR 63.43(g)(2)(iv), the permittee shall comply with all applicable requirements contained in 40 C.F.R. part 63, subpart A.
   b) The permittee shall install control devices selected as BACT.

2. Emission Limitations:

   a) Pursuant to Regulations 401 KAR 59:016, Section 3(1)(b), and 401 KAR 51:017, particulate emissions shall not exceed 0.018 lb/mmBtu heat input from each unit based on a three-hour average. Pursuant to 401 KAR 59:016, Section 6(1), compliance with the 0.018 lb/mmBtu emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, Section 3(1)(b).

   b) Pursuant to 401 KAR 59:016, Section 3(2), emissions from each unit shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute period per hour.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to Regulations 401 KAR 59:016, Section 4(1) and 401 KAR 51:017, sulfur dioxide emissions shall not exceed 0.167 lbs/mmBtu from each unit based on a thirty (30) day rolling average.

d) Pursuant to 401 KAR 59:016, Section 4(1) and 401 KAR 51:017, sulfur dioxide emission shall not exceed 0.41 lbs/mmBtu, based on 24 hr block average. See Section D for procedures to be used to revised this limitation after optimization study.

e) Pursuant to Regulations 401 KAR 51:017, carbon monoxide emissions shall not exceed 0.10 lbs/mmBtu from each unit based on a thirty (30) day rolling average.

f) Pursuant to Regulations 401 KAR 59:016, Section 5(1)(c) and 401 KAR 51:017, nitrogen oxides emissions shall not exceed 0.08 lbs/mmBtu from each unit based on a thirty (30) day rolling average. Pursuant to 401 KAR 59:016, Section 6(2), compliance with the 0.08 lb/mmBtu emission limitation shall constitute compliance with the 65% reduction requirement contained in 401 KAR 59:016, Section 5(2).

g) Pursuant to Regulations 401 KAR 51:017, VOC emissions shall not exceed 0.0072 lbs/mmBtu from each unit based on a thirty (30) day rolling average. Compliance with this limit shall be demonstrated by compliance with Subsection 2(e) above

h) Pursuant to Regulations 401 KAR 51:017, beryllium emissions shall not exceed 0.000000944 lbs/mmBtu from each unit based on a quarterly average.

i) Pursuant to Regulations 401 KAR 51:017, sulfuric acid mist emissions shall not exceed 0.00497 lbs/mmBtu from each unit based on a thirty (30) day rolling average.

j) Pursuant to Regulations 401 KAR 51:017, hydrogen fluoride emissions shall not exceed 0.000159 lbs/mmBtu from each unit based on a thirty (30) day rolling average.

k) Pursuant to Regulations 401 KAR 51:017, mercury emissions shall not exceed 0.00000321 lbs/mmBtu from each unit based on a quarterly average.

l) Pursuant to Regulations 401 KAR 51:017, lead emissions shall not exceed 0.00000386 lbs/mmBtu from each unit based on a quarterly average.

m) Pursuant to 40 CFR. 63.43(d), case-by-case MACT determination, each pulverized coal fired steam electric generating unit, shall not exceed the following hazardous air pollutants (HAP) emission limitations listed below:

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

HAP	Emissions Limitation (tons/yr.-per unit)
VOC (HAPs)	5.154
Mercury	0.1047
Hydrogen Chloride	26.90
Hydrogen Fluoride	5.1684
Arsenic	0.0288
Beryllium	0.0308
Chromium	0.3419
Manganese	0.6825
Lead	0.126
Cadmium	0.0119

3. Testing Requirements:

a) Pursuant to 401 KAR 50:055, Section 2(1)(a) the permittee shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of each emission unit. Opacity data from the Continuous Opacity Monitor (COM) during the performance test for particulate shall be correlated with the particulate emissions rate to establish an average opacity level pursuant to Condition 4.b below.

b) If no additional stack tests are performed pursuant to Condition 4.b, the permittee shall conduct a performance test for particulate emissions annually after demonstrating compliance with the allowable standard.

c) Pursuant to 401 KAR 50:045, Section 2 and 50:015, Section 1, the permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 annually, or more frequently if requested by the Division.

d) See Section D.

e) Case-by-Case MACT Requirements
Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination, the permittee shall demonstrate compliance with the applicable emissions limitations for the following HAPs in the table below

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

HAP	Compliance Method
VOC (HAPs)	Method 18 or 25
Mercury	Method 29
Hydrogen Chloride	Method 26A
Hydrogen Fluoride	Method 26A
Arsenic	Method 29
Beryllium	Method 29
Chromium	Method 29
Manganese	Method 29
Lead	Method 29
Cadmium	Method 29

f) Pursuant to 40 CFR 63.43(g)(2)(ii) case-by case MACT determination, the permittee shall demonstrate compliance with these emissions limitations within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after initial startup of these emissions units. See Section G(d)5

g) Pursuant to 401 KAR 52:020, Section 10, during the initial compliance test, the permittee shall take a representative sample of the fuel "as fired" and analyze it to determine the HAP content in the fuel. This information shall be used to establish a correlation between the sample's HAP content and HAP emissions for monitoring purposes, except for VOC(HAPs). The permittee shall demonstrate compliance with these emissions limits annually. This testing shall be used to validate the correlation between composite sample HAP content and HAP emissions, except for VOC(HAPs).

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7; and 401 KAR 59:005, Section 4, the permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, carbon monoxide emissions, nitrogen oxides emissions and either oxygen or carbon dioxide emissions. Oxygen or carbon dioxide shall be monitored at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4. The continuous opacity monitor (COM) may be located after the ESP and before the WFGD to avoid complications with installation in the wet stack.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(1), to meet the periodic monitoring requirement for particulate, the permittee shall use a continuous opacity monitor (COM). The average opacity level determined pursuant to condition 3.a above, plus 5% opacity will become the opacity trigger level. Excluding the startup, shut down, and once per hour exemption periods, if any six-minute average opacity (averaged over a period of 3 hours) value exceeds the opacity trigger level, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs. If five (5) percent or greater of COM data (excluding startup, shut down, and malfunction periods, data averaged over a three hour period) recorded in a calendar quarter show excursions above the opacity trigger level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by condition Section G(a)(17) of this permit before conducting the test. The Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

c) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(1), to meet the periodic monitoring requirement for opacity, the permittee shall use a continuous opacity monitor (COM). The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a monthly basis and maintain a log of the observations. If any visible emissions are seen, then opacity must be determined using Reference Method 9, or by accepting the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs. Observations shall revert to weekly if visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any monthly observation. Weekly observations shall continue until such time that no visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any three consecutive week period.

d) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(2), to meet the periodic monitoring requirement for sulfur dioxide, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 30 day rolling average or 24 block average sulfur dioxide value exceeds that standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

e) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(3), to meet the periodic monitoring requirement for nitrogen oxide, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 30 day rolling average nitrogen oxide value exceeds the standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or CEM system and make any necessary repairs or take any corrective actions as soon as practicable.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

f) Pursuant to Regulations 401 KAR 52:020, Section 10, and 401 KAR 51:017, to meet the periodic monitoring requirement for CO, the permittee shall use a continuous emission monitor (CEM).

g) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(5), all the continuous emission monitoring systems shall be operated and data shall be recorded during all periods of operation of the emissions units including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

h) Pursuant to 401 KAR 52:020 and 401 KAR 59:016, Section 7(6), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, the permittee shall obtain emission data by using other monitoring systems as approved by the Division or the reference methods as described in 401 KAR 59:016, Section 7(8) to provide emission data for a minimum of eighteen hours in at least twenty-two out of thirty successive boiler operating days.

i) Pursuant to 401 KAR 59:016, Section 7(9), the following procedures shall be used to conduct monitoring system performance evaluations and calibration checks as required under 401 KAR 59:005, Section 4(3).

1. Reference Method 6 or 7, as applicable shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous emission monitoring systems.

2. Sulfur dioxide or nitrogen oxides, as applicable, shall be used for preparing calibration mixtures under Performance Specification 2 of Appendix B to 40 CFR 60 incorporated by reference in 401 KAR 50:015.

3. The span value for the continuous monitoring system for measuring opacity shall be between sixty (60) and eight (80) percent and the continuous monitoring system for measuring nitrogen oxides shall be 1,000 ppm.

4. The span value for the continuous monitoring system for measuring sulfur dioxide at the outlet of the control device shall be 50 percent of the maximum estimated hourly potential emissions of the fuel fired, or span values as specified in 40 CFR 75, Appendix A.

j) Pursuant to 401 KAR 52:020, Section 10, the permittee shall take a sample of the fuel "as fired" to the PCs on a daily basis. The samples taken on a daily basis shall be uniformly mixed to form a composite sample analyzed once per calender quarter to determine mercury, arsenic, beryllium, chromium, magnesium, lead, cadmium, fluorine and chlorine content. This data, along with the baseline data established during the initial compliance test, shall be used to demonstrate compliance with the emission limits for these pollutants.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

k) CAM Requirements
The permittee shall use Sulfur Dioxide (SO_2) and Nitrogen Oxides (NOx) Continuous Emissions Monitors (CEMs) as continuous compliance determination methods to preclude applicability of 40 CFR 64 for those specific parameters, and to demonstrate compliance with Best Available Control Technology (BACT) limits contained in this permit

l) Pursuant to 40 CFR 64.6, monitoring for Particulate Matter (PM), Hydrogen Fluoride (HF) and H_2SO_4 is shown in the table below

TABLE: MONITORING APPROACH

Applicable CAM Requirement	PM/PM_{10}	HF	H_2SO_4
General Requirements	0.018 lb/mmBtu 20% Opacity	0.000159 lb/mmBtu 30-day rolling average	0.00497 lb/mmBtu 30-day rolling average
Monitoring Methods and Location	Initial Source Test & (1) installation of a COM at outlet of the dry ESP and monitoring of the ESP/WESP electrical field and other relevant parameters identified during initial testing* or (2) visual observation of plume from stack	SO_2 CEMs plus initial source test, coal sampling	SO_2 CEMs plus initial source test, coal sampling
Indicator Range	(1) Initial source testing to establish COM and equipment parameter indicator ranges, including the ESP/WESP electrical fields, as appropriate or (2) Initial source testing to establish compliance with the PM limit at 20% opacity. The permittee must conduct weekly stack observations. If visible emissions are seen, the permittee must conduct a Method 9 observation to determine the opacity of the emissions.	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate
Data Collection Frequency	(1) Continuous COM and control device operating parameters or (2) weekly observations	Continuous CEM, quarterly coal composites	Continuous CEM, quarterly coal composites
Averaging Period	(1)Opacity – 6 minute averages COM control device parameters – 3 hours or (2) Visible Emission Surveys – 1 minute; Method 9	30-day	30-day
Recordkeeping	COM data system records and control device parameters will be maintained for a period of 5 years or visible observation records and method 9 observations will be kept in a designated logbook and maintained for a period of 5 years.	Coal quality information will be kept in a designated log book, plus CEM data system records	Coal quality information will be kept in a designated log book, plus CEM data system records

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

QA/QC	COM will be maintained and operated in accordance with 401KAR 59:005 / 40CFR 60 Appendix B and/or other requirements as applicable, ESP/WESP monitored parameters will be maintained and operated in accordance with manufacturer recommendations; or records of method 9 certifications will be maintained	FGD/WESP will be maintained and operated in accordance with manufacturer recommendations	FGD/WESP will be maintained and operated in accordance with manufacturer recommendations

* 40 CFR 60, Subpart Da, allows the alternative location of COMS, in cases where the stack is considered to be wet (as the TGS stack will be upstream of the wet scrubber after the particulate control device). In the case of TGS, the particulate control consists of the dry ESP prior to the wet scrubber and a WESP after the wet scrubber. Therefore, COMS cannot be installed in TGS's wet stacks due to the inaccurate opacity readings. Hence, TGC proposes to install COMS at the outlets of the ESPs, and to identify appropriate PM operating parameters for the ESPs and WESPs (such as electrical field monitoring or operation or other parameters) within 180 days after initial source testing, with appropriate collection frequencies, recordkeeping, indicator ranges and QA/QC. In the alternative, TGC proposes to use periodic visible observations with requirements to use method 9 surveys as needed.

m) Case-by-Case MACT and CAM Requirements

Pursuant to 40 CFR 63.43 (g)(2)(ii), case-by-case MACT determination, and 40 CFR 64.6(c)(1), the permittee shall conduct the following monitoring to assure compliance with the applicable requirements:

HAP	Monitoring Method
VOC (HAPs)	The continuous compliance monitoring method used to assess compliance with the carbon monoxide emission limitation shall be used as an indicator of good combustion practices. Compliance with the carbon monoxide emission limitation assures compliance with the VOC (HAPs) emission limit.
Mercury	The permittee shall take a sample of fuel "as fired" to the PCs on a daily basis. The samples taken on a daily basis shall be uniformly mixed to form a composite sample analyzed to determine mercury content on a quarterly basis. This data, along with the baseline data established during the initial compliance and subsequent tests, shall be used to demonstrate compliance with the emission limits for these pollutants. [The pH level and liquid flow rate shall be monitored in the wet -flue gas desulfurization unit as an indicator of proper removal of mercury from the exhaust stream. The wet electrostatic precipitator voltage shall be monitored as an indicator of proper operation and removal of mercury from the exhaust stream.]
Hydrogen Chloride	The continuous compliance monitoring method used to assess compliance with the sulfur dioxide emission limitations shall be used to assure compliance with the hydrogen chloride emission limit. Compliance with the sulfur dioxide emission limitations assures compliance with the hydrogen chloride emissions limit.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Hydrogen Fluoride	The continuous compliance monitoring method used to assess compliance with the sulfur dioxide emission limitations shall be used to assure compliance with the hydrogen fluoride emission limit. Compliance with the sulfur dioxide emission limitations assures compliance with the hydrogen fluoride emissions limit.
Arsenic, Beryllium, Chromium, Manganese, Lead, and Cadmium	The permittee shall take a sample of fuel "as fired" to the PCs on a daily basis. The samples taken on a daily basis shall be uniformly mixed to form a composite sample analyzed to determine arsenic, beryllium, chromium, manganese, lead and cadmium content on a quarterly basis. This data, along with the baseline data established during the initial compliance and subsequent tests, shall be used to demonstrate compliance with the emission limits for these pollutants. [The wet and dry electrostatic precipitator voltage shall be monitored as an indicator of proper operation and removal of arsenic, beryllium, chromium, manganese, lead and cadmium from the exhaust stream.]

n) Pursuant to 40 CFR 63.43 (g)(2)(ii), case-by-case MACT determination and 40 CFR 64.6(c)(1), the permittee shall conduct a compliance demonstration annually to validate the correlation between the coal samples HAP content and HAP emissions. The test procedure shall consist of taking samples of coal "as-fired" concurrent with the compliance demonstration to correlate the HAP content of coal with the HAP emissions. The coal samples shall be analyzed for HAP content and the correlation with the HAP emissions shall be established based on the analyzed HAP content and stack emissions.

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including continuous emission monitoring system, monitoring device, and performance testing measurements; all continuous emission monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a continuous emission monitoring system or emission monitoring device is inoperative.

c) Pursuant to 401 KAR 50:055, Section 4, the permittee shall compute and record percentage of the COM data (excluding startup, shut down, and malfunction data) showing excursions above the opacity trigger level in each calendar quarter.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

d) Pursuant to regulation 401 KAR 52:020, Section 10 and 401 KAR 50:045, Section 6, the permittee shall maintain the results of all compliance tests.

e) Case-by-Case MACT and CAM Requirements

1. Pursuant to 40 CFR 63.43(g)(2)(ii), the permittee shall keep quarterly records of the sample's HAP analyses. The permittee shall keep these records according to the general recordkeeping requirements specified in Section F.1. and F.2. of this permit.

2. Pursuant to 40 CFR 63.43(g)(2)(ii), and 40 CFR 64.9(b), the permittee shall record continuously for the wet limestone scrubber the following:

   a. The scrubber liquid pH at the liquor inlet;
   b. The liquid flow rate in gallons per minute at the pump discharge or scrubber liquor inlet.

3. Pursuant to 40 CFR 63.43(g)(2)(ii), and 40 CFR 64.9(b), the permittee shall continuously record voltages for the wet electrostatic precipitator and dry electrostatic precipitator.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) All hourly averages shall be reported for sulfur dioxide, carbon monoxide and nitrogen oxides monitor. The hourly averages shall be made available in the format specified by the Division.

3) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

6) For sulfur dioxide, carbon monoxide and nitrogen oxides, all information listed in 401 KAR 59:016, Section 9(2)(a) through (i), shall be reported to the Division for each twenty-four (24) hour period.

7) If the minimum quantity of emission data as required by 401 KAR 59:016, Section 7 is not obtained for any thirty successive boiler operating days, the permittee shall report all the information listed in 401 KAR 59:016, Section 9(3) for that thirty (30)day period.

8) If any sulfur dioxide standards as specified in 401 KAR 59:016, Section 4(a and b) are exceeded during emergency conditions because of control system malfunction, the permittee shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(4).

9) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the permittee shall submit a signed statement pursuant to 401 KAR 59:016, Section 9(6) indicating if any changes were made in the operation of the emission control system during the period of data unavailability. Operations of control system and emissions units during periods of data unavailability are to be compared with operation of the control system and emissions units before and following the period of data unavailability.

10) The permittee shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(7).

11) Pursuant to 401 KAR 59:016, Section 9(8), for the purposes of the reports required under 401 KAR 59:005, Section 4, periods of excess emissions are defined as all six (6) minute periods during which the average opacity exceeds the applicable opacity standards as specified in 401 KAR 59:016, Section 3(2). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter. Continuous emissions monitoring for sulfur dioxide and nitrogen oxide shall be certified, operated and maintained in accordance with the applicable provisions of 40 CFR Part 75, compliance with which shall be deemed compliance with monitoring provisions of 40 CFR 60.47a

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 59:005, Section 3(3), the permittee shall report the number of excursions (excluding startup, shut down, malfunction data) above the opacity trigger level, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity trigger level in each calendar quarter to the Division's Regional Office.

c) CAM Requirements
Pursuant to 40 C.F.R. §64.9(a) the permittee shall report the following information according to the general reporting requirements specified in Section F.5. of this permit:

a. Number of exceedances or excursions;
b. Duration of each exceedance or excursion;
c. Cause of each exceedance or excursion;
d. Corrective actions taken on each exceedance or excursion;
e. Number of monitoring equipment downtime incidents;
f. Duration of each monitoring equipment downtime incident;
g. Cause of each monitoring equipment downtime incident;
h. Description of actions taken to implement a quality improvement plan and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 2 (5), the SCR ESP, WFGD, and WESP, shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and / or standard operating practices.

b) Pursuant to 401 KAR 50:055, Section 2 (1)(a), a compliance demonstration for the FGD, flue gas desulfurization system, must be completed within 180 days of start-up. If compliance with the 0.167 lb/mmBtu sulfur dioxide emissions limit is not met within this initial compliance period, operations at the facility must be suspended until all necessary modifications to control equipment are completed. During this period, the facility can be in operation only for the purpose of demonstrating compliance.

c) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

d) See Section E for further requirements.

e) Case-by-Case MACT Requirements
Pursuant to 40 CFR 63.43(d), the permittee shall install and operate the following control technology to meet the case-by-case MACT emission limitations while emission units are in operation

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

HAP	Control Technology
VOC (HAPs)	Good combustion practices
Mercury	Low NOx burners, selective catalytic reduction (SCR), electrostatic precipitator, wet flue gas desulfurization and wet electrostatic precipitator with 80% (aprox) combined control efficiency
Acid Gases (Hydrogen Chloride and Hydrogen Fluoride)	Wet limestone scrubber and wet electrostatic precipitator with 98% (aprox) combined control efficiency
Metals (Arsenic, Beryllium, Cadmium Chromium, Lead and Manganese)	Wet and Dry Electrostatic Precipitator with 99.5 to 99.9% control efficiency for PM (aprox.)

Control Equipment Operating Conditions for the wet limestone scrubber:

Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination and 40 CFR 64.6(c)(2), the permittee shall maintain the liquor pH level within the range that demonstrated compliance in the most recent compliance demonstration. The permittee must maintain the liquid flow rate within the range that demonstrated compliance in the most recent compliance demonstration.

Control Equipment Operating Conditions for the wet electrostatic precipitator and dry electrostatic precipitator:

Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination and 40 CFR 64.6(c)(2), the permittee shall maintain the wet electrostatic precipitator and dry electrostatic precipitator voltage equal to or above the level that demonstrated compliance in the most recent compliance demonstration.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 03 Auxiliary Boiler AB001

Description:
300 mmBtu/hr low sulfur (0.05% sulfur) diesel fired auxiliary boiler
Construction Commenced Date: estimated 2002

Applicable Regulations:

40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, incorporated by reference in regulation 401 KAR 60:005, Section 3(1)(b).
401 KAR 59:015, New indirect heat exchangers.
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances.
40 CFR 60, Appendix F, Quality Assurance Procedures.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   The auxiliary boiler shall only operate during start-up periods of one utility boiler or when no utility boilers are in operation. The auxiliary boiler shall nor operate more than 500 hours per twelve (12) consecutive months [401 KAR 51:001, Section 1 (142)].

2. Emission Limitations:

   a) Pursuant to Regulations 401 KAR 60:005, Section 3(1)(b), 401 KAR 59:015, Section 4(1)(b), and 401 KAR 51:017, particulate emissions shall not exceed 0.06 lb/mmBtu heat input based on a three-hour average.

   b) Pursuant to 401 KAR 59:015, Section 4(2)(a), emissions from the utility boiler shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute period per hour.

   c) Pursuant to Regulations 401 KAR 60:005, Section 3(1)(b); 401 KAR 59:015, Section 5(1)(b); and 401 KAR 51:017, sulfur dioxide emissions shall not exceed 0.05 lbs/mmBtu based on a three-hour average.

   d) Pursuant to Regulations 401 KAR 51:017, carbon monoxide emissions shall not exceed 0.06 lbs/mmBtu based on a thirty (30) day rolling average.

   e) Pursuant to Regulations 401 KAR 60:005, Section 3(1)(b); 401 KAR 59:015, Section 6(1)(b); and 401 KAR 51:017, nitrogen oxides emissions shall not exceed 0.12 lbs/mmBtu based on a three-hour average.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

f) Pursuant to Regulations 401 KAR 51:017, VOC emissions shall not exceed 0.03 lbs/mmBtu based on a thirty (30) day rolling average.

3. Testing Requirements:

a) Pursuant to Regulations 401 KAR 59:005, Section 2(1) and 401 KAR 59:015, Section 8, the permittee shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

b) Pursuant to 401 KAR 59:015, Section 8(1)(f), if the unit has operated during the previous 12 consecutive months, the permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 annually, or more frequently if requested by the Division.

c) The permittee shall conduct a performance test for particulate emissions annually after demonstrating compliance with the allowable standards.

d) See Section D.

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 52:020; 401 KAR 60:005; 401 KAR 59:015, Section 7; 401 KAR 51:017; and 401 KAR 59:005, Section 4, the permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems or use other monitoring methods as allowed by regulation, for measuring the opacity of emissions, sulfur dioxide emissions, carbon monoxide emissions, nitrogen oxides emissions and either oxygen or carbon dioxide emissions. Oxygen or carbon dioxide shall be monitored at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4.

b) Pursuant to 401 KAR 52:020; 401 KAR 51:017; and 401 KAR 59:015, to meet the periodic monitoring requirement for sulfur dioxide, the permittee shall use a continuous emission monitor (CEM).

c) Pursuant to 401 KAR 52:020; 401 KAR 51.:017; and 401 KAR 59:015, to meet the periodic monitoring requirement for nitrogen oxide, the permittee shall use a continuous emission monitor (CEM).

d) Pursuant to 401 KAR 52:020; and 401 KAR 51:017, to meet the periodic monitoring requirement for CO, the permittee shall use a continuous emission monitor (CEM).

e) Pursuant to 401 KAR 52:020; 401 KAR 59:015; and 401 KAR 51:017 all the continuous emission monitoring systems shall be operated and data shall be recorded during all periods of operation of the emissions units including periods of

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

f) Pursuant to 401 KAR 59:015, Section 7(3), the following procedures shall be used to conduct monitoring system performance evaluations and calibration checks as required under 401 KAR 59:005, Section 4(3).

g) Pursuant to 401 59:015, Section 7(3)(a), Reference Method 6 or 7, as applicable shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous emission monitoring systems.

h) Pursuant to 401 59:015, Section 7(3)(b), Sulfur dioxide or nitrogen oxides, as applicable, shall be used for preparing calibration mixtures under Performance Specification 2 of Appendix B to 40 CFR 60 filed by reference in 401 KAR 50:015.

i) Pursuant to 401 59:015, Section 7(3)(c), The span value for the continuous monitoring system for measuring opacity shall be 80, 90, or 100 percent and the continuous monitoring system shall be 500 ppm for measuring nitrogen oxides and 1,000 ppm for measuring sulfur oxides.

j) The permittee shall monitor the hours of operation during each twelve (12) consecutive months.

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of the indirect heat exchanger shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.

c) The permittee shall maintain the results of all compliance tests.

d) The permittee shall maintain records of hours of operation during each twelve (12) consecutive months.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1. The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2. All hourly averages shall be reported for sulfur dioxide, carbon monoxide, and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the Division.

3. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

4. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

b) The permittee shall report the number of excursions (excluding startup, shut down, malfunction data) above the opacity trigger level, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity trigger level in each calendar quarter to the Division Regional Office.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the boiler shall be operated in accordance with manufacturer's specifications and / or standard operating practices.

b) See Section E for further requirements.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 04 Coal Handling Systems

Description:

Machine Point 01 - CDC001	Convey and Transfer (Stockout)
Machine Point 02 - CDC002a	Convey and Transfer (Reclaim Primary)
Machine Point 03 - CDC002b	Convey and Transfer (Reclaim Secondary)
Machine Point 04 - CDC003	Crusher Tower and Convey
Machine Point 05 - CDC004	Convey and Plant Surge Bin
Machine Point 06 - CDC005	Silo 1 East
Machine Point 07 - CDC006	Silo 1 West
Machine Point 08 - CDC007	Silo 2 East
Machine Point 09 - CDC008	Silo 2 West
Machine Point 10 - CFD004	Stacker/Reclaim(while in reclaim operation)
Machine Point 11 - CFD005	Convey/Transfer(while in reclaim operation)
Machine Point 12 - CFD007	Secondary Reclaim Endloader

Control Equipment:

Enclosures and Baghouse	Machine Points 01 – 05
Bin Filters	Machine Points 06 – 09
Partial Enclosure/Low Drop/ Filter	Machine Point 11

Operating Rate:

2000 tons/hour (each transfer)	Machine Point 01 - 4 transfers
	Machine Point 10 -12
1000 tons/hour (each transfer)	Machine Point 02 - 2 transfers
	Machine Point 04 – 8 transfers
	Machine Point 05 – 6 transfers
	Machine Point 06 – 3 transfers
	Machine Point 07 – 3 transfers
	Machine Point 08 – 3 transfers
	Machine Point 09 – 3 transfers
500 tons/hour (each transfer)	Machine Point 03 – 2 transfers

Construction Commenced Date: Estimated Early 2002

Applicable Regulations:

401 KAR 60:005, incorporation by reference 40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation Plants
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

1. Operating Limitations:

   Pursuant to 401 KAR 51:017, the permitee shall install control methods selected as BACT

2. Emission Limitations:

   a) Pursuant to 40 CFR 60.252, the owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

   b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a particulate design control efficiency of at least 99%.

3. Testing Requirements:

   Pursuant to 401 KAR 60:005, incorporating by reference 40 CFR 60:254, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 annually, and procedures in 40 CFR 60.8 or more frequently if requested by the Division.

4. Specific Monitoring Requirements:

   The permittee shall perform a qualitative visual observation of the opacity of emissions from each emission point on a weekly basis and maintain a log of the observations. If visible emissions from any emission point are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

5. Specific Record Keeping Requirements:

   a) The permittee shall maintain the records of amount of coal received and processed.

   b) The permittee shall maintain the results of all compliance tests. The permittee shall record each week, the date and time of each observation and opacity of visible emissions monitoring. In case of exceedances, the permittee must record the reason (if known) and the measures taken to minimize or eliminate exceedances.

6. Specific Reporting Requirements:

   See Section F, Conditions 5, 6, 7 and 8.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

   a) Pursuant to 401 KAR 50:055, Section 5, the enclosures/partial enclosures, baghouse, bin filters, low-pressure drop and telescopic chutes shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 40 CFR 60, Subpart Y and in accordance with manufacturer's specifications and/or standard operating practices

   b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

   c) See Section E for further requirements.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 05 Coal Handling System

Description:

Machine Point 01 - CFD001	Stacker Operation
Machine Point 02 - CFD002	Stacker Operation
Machine Point 03 - CFD003	Stacker/Reclaim (while in stacker operation)
Machine Point 04 - CFD006	Secondary Stacker

Control Equipment:

Partial Enclosures/Low Drops	Machine Points 01 - 04
Telescopic Chute and Low Drop	Machine Point 03 and 04

Operating Rate:

2000 tons/year	Machine Points 01 - 04

Construction Commenced Date: Estimated 2002

Applicable Regulations:

401 KAR 63:010, Fugitive emissions
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not limited to the following:

      1. Application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dust;
      2. Installation and use of compaction or other measures to suppress the dust emissions during handling;

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

   c) Pursuant to 401 KAR 51:017, the permitee shall install control methods selected as BACT.

2. Emission Limitations:
   None

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. Testing Requirements:

   None

4. Specific Monitoring Requirements:

   The permittee shall monitor fugitive emissions from partial enclosures, low-pressure drop and telescopic chutes weekly as required by Best Available Control Technology (BACT)

5. Specific Record Keeping Requirements:

   a) The permittee shall maintain records of the amount of coal received and processed.

   b) The permitee shall maintain a log of the date, time and results of the monitoring required in subsection 4 above

6. Specific Reporting Requirements:

   See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

   a) Pursuant to 401 KAR 50:055, Section 5, the partial enclosures, low-pressure drop and telescopic chutes shall be maintained, operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010, and in accordance with manufacturer's specifications and/or standard operating practices

   b) See Section E for further requirements

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 06 Coal Piles

Description:

Machine Point 01 – 14a	North Coal Storage Pile
Machine Point 02 – 14a	South Coal Storage Pile
Machine Point 03 – 14b	Secondary Pile
Machine Point 04 – 14c	Emergency Pile
Machine Point 05 – 14d	Endloaders

Control Equipment: Compaction

Operating Rate:

7.72 acres	Machine Point 01
5.65 acres	Machine Point 02
1.84 acres	Machine Point 03
0.72 acres	Machine Point 04
2000 tons/hour	Machine Point 05

Construction Commenced Date: Estimated 2002

Applicable Regulations:

401 KAR 63:010, Fugitive Emissions
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not limited to the following:

      1. Application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dust;

      2. Installation and use of compaction or other measures to suppress the dust emissions during handling;

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

   c) Pursuant to 401 KAR 51:017, the permitee shall install control methods selected as BACT.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:

   None

3. Testing Requirements:

   None

4. Specific Monitoring Requirements:

   The permittee shall monitor fugitive emissions from the Coal Piles weekly as required by Best Available Control Technology (BACT). See above.

5. Specific Record Keeping Requirements:

   a) The permittee shall maintain the records of amount of coal received and processed.

   b) The permitee shall maintain a log of the date, time and results of the monitoring required in subsection 4 above.

6. Specific Reporting Requirements:

   See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

   a) Pursuant to 401 KAR 50:055, Section 5, the Coal Piles shall be maintained, to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010, and standard operating practices.

   b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

   c) See Section E for further requirements.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 07 FGD Reagent Prep Handling

Description:

Machine Point 01 - LDC001	Convey/Transfer Structure 1
Machine Point 02 - LDC002	Convey/Transfer Structure 2
Machine Point 03 - LDC003	Convey/Transfer Structure 3
Machine Point 04 - LDC005	Storage Bins (2)
Machine Point 05 - LFD003	Convey to Pile (Stockout)
Machine Point 06 - LFD004	Pile to Belt (Reclaim)

Control Equipment:

Enclosures / Filters	Machine Points 01 – 03 & 06

Operating Rate:

400 tons/hour (each)	Machine Points 01 – 06

Construction Commenced Date: Estimated Early 2002

Applicable Regulations:

401 KAR 60:670, incorporating by reference 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, as modified by Section 3 of 401 KAR 60:670

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   Pursuant to 401 KAR 51:017, the permitee shall install control equipment selected as BACT.

2. Emission Limitations:

   a) Pursuant to Regulations 401 KAR 51:017, and 401 KAR 60:670, emissions of particulate shall be controlled by filters.

   b) Pursuant to 401 KAR 60:670, specifically 40 CFR 60.672(a), emissions of particulate shall not exceed 0.05 gr/dscm and shall not exhibit greater than 7% opacity.

   c) Pursuant to 401 KAR 60:607, specifically 40 CFR 60.672(b), emissions of particulate shall not exhibit greater than 10% opacity (Mp 01-03, 06).

3. Testing Requirements:

   a) Pursuant to 401 KAR 60:670, specifically 40 CFR 60.675(b)(2), the owner and/or operator shall use EPA Reference Method 9 and the procedures in 40 CFR 60.11 to determine opacity, annually.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to Regulations 401 KAR 60:670 and 40 CFR 60.675(b)(1), EPA Reference Method 5 or Method 17 shall be performed as required by the Division to determine compliance with the particulate matter concentration emission limit.

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 51:017 and 401 KAR 60:670, the permittee shall perform a qualitative visual observation of the opacity of emissions from each emission point on a weekly basis and maintain a log of the observations. If visible emissions from any emission point are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

5. Specific Recordkeeping Requirements:

a) Reporting and Recordkeeping shall be done in compliance with the requirements contained within 401 KAR 60:670, specifically 40 CFR 60.676.

b) The permittee shall maintain a log of the date, time and results of the monitoring required in Subsection 4 above.

c) Records of the lime processed (tonnage) shall be maintained.

d) See Section F, Conditions 5, 6, 7 and 8.

6. Specific Reporting Requirements:

Pursuant to 401 KAR 60:670, specifically 40 CFR 60.676, the owner and/or operator shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672, including reports of opacity observations made using EPA Reference Method 9.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the filter and enclosures shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 40 CFR 60,Subpart OOO and in accordance with manufacturer's specifications and/or standard operating practices

b) Pursuant to 401 KAR 50:050, Section 1, records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 08 FGD Reagent Prep Handling (Fugitives)

Description:

Machine Point 01 - LFD001	Barge Unload Bucket to Hopper
Machine Point 02 - LFD002	Unload Hopper to Feeder
Machine Point 03	Storage Pile
Machine Point 04	Inactive Pile
Machine Point 05 - LDC004A	Rail Unload
Machine Point 06 - LDC004B	Rail Unload

Control Equipment:

Partial Enclosures / Filters	Machine Points 05 - 06

Operating Rate:

400 tons/hour	Machine Points 01 - 02
0.72 acres	Machine Point 03
1.8 acres	Machine Point 04
200 tons/hour (each)	Machine Points 05 - 06

Construction Commenced Date: Estimated 2002

Applicable Regulations:

401 KAR 63:010, Fugitive Emissions
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not limited to the following:

      1 Application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dust; and

      2. Installation and use of compaction or other measures to suppress the dust emissions during handling;

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

c) Pursuant to 401 KAR 51:017, the permitee shall install control methods selected as BACT.

2. Emission Limitations:

None

3. Testing Requirements:

None

4. Specific Monitoring Requirements:

The permittee shall monitor fugitive emissions weekly from each emission point. Enclosures demonstrate compliance with the requirements of 401 KAR 63:010 and Best Available Control Technology (BACT)

5. Specific Record Keeping Requirements:

a) The permittee shall maintain a log of the date, time, and results of the monitoring required in Subsection 4 above.

b) The permitee shall maintain the records of amount of limestone received and processed.

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the partial enclosures and filters shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices

b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 09 Fly Ash Handling System FADC001A and FADC001B

Description:

Fly Ash Silo Bins (2)

Control Equipment:	Filter
Operating Rate:	75 tons/hour (each)
Construction Commenced Date:	Estimated Early 2002

Applicable Regulations:

401 KAR 59:010, New Process Operations
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   Pursuant to 401 KAR 51:017, the permitee shall install control methods selected as BACT.

2. Emission Limitations:

   a) Pursuant to Regulations 401 KAR 59:010, the permittee shall not cause to be discharged into the atmosphere from any of the above mentioned emissions units gases which exhibit twenty (20) percent opacity or greater.

   b) Pursuant to State 401 KAR 59:010, particulate matter emissions from the bin filter shall not exceed [$3.59 (P)^{0.62}$] lbs/hr based on a three-hour average, where P is the flyash rate in tons/hr.

3. Testing Requirements:

   a) Pursuant to 401 KAR 59:010, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 annually, or more frequently if requested by the Division.

   b) Pursuant to 401 KAR 59:010, EPA Reference Method 5 shall be performed as required by the Division to determine compliance with the particulate matter concentration emission limit.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

   The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

5. Specific Record Keeping Requirements:

   a) The permittee shall maintain the records of amount of ash processed.

   b) Pursuant to 401 KAR 59:005, Section 3(4), the permittee shall maintain the results of all compliance tests and calculations.

   c) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

6. Specific Reporting Requirements:

   See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

   a) Pursuant to 401 KAR 50:055, Section 5, the filter equipment shall be maintained and operated to ensure the emission unit is in compliance with applicable requirements of 401 KAR 59:010 and in accordance with manufacturer's specifications and/or standard operating practices

   b) Pursuant to 401 KAR 59:005, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

   c) See Section E for further requirements.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 10 and 11 Two Cooling Towers CT1 and CT2

Description:

Control Equipment:	0.002% Drift Eliminators
Operating Rate:	345,910 GPM each
Construction Commenced Date:	Estimated 2002

Applicable Regulations:

401 KAR 63:010, Fugitive emissions
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. Emission Limitations:

   a) Pursuant to regulation 401 KAR 51:017, the cooling towers shall utilize 0.002% Drift Eliminators.

   b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. Testing Requirements:

   None

4. Specific Monitoring Requirements:

   The Permittee shall measure the total dissolved solids (TDS) content on at least a monthly basis. Measurement of TDS in the wastewater discharge permit associated with the units as required by a National Pollutant Discharge Elimination System (NPDES) permit, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce the TDS content.

SECTION B – EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. Specific Record Keeping Requirements:

   a) The permittee shall maintain records of the manufacturer's design of the Drift Eliminators.

   b) The permittee shall maintain records of water circulation.

6. Specific Reporting Requirements:

   See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

   a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

   b) See Section E for further requirements.

SECTION C – INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. While these activities are designated as insignificant, the permittee must comply with the applicable regulation(s). Process and emission control equipment at each insignificant activity subject to a generally applicable regulation shall be inspected monthly and a qualitative visible emissions evaluation made. The results of the inspections and observations shall be recorded in a log, noting color, duration, density (heavy or light), cause and corrective actions taken for any abnormal visible emissions.

	Description	Generally Applicable Regulation
1.	Fire Water Pumps (2) Number two low sulfur (0.05% sulfur) fuel oil Fired (1) Electric	None
2.	Maintenance Shop Activities	None
3.	Number two low sulfur (0.05% sulfur) Fuel Oil Storage Tanks	401 KAR 59:050
4.	Miscellaneous Water Storage Tanks	None
5.	FGD Solid Waste By-product Handling and Long-term Storage	401 KAR 63:010
6.	Number two low sulfur (0.05% sulfur) Diesel Fired Emergency Generator	None
7.	Ammonia Tanks	401 KAR 68
8.	Haul Roads	401 KAR 63:010

SECTION D – SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1) PM/PM_{10}(filterable and condensable), sulfur dioxide, carbon monoxide, nitrogen oxides, VOC and visible (opacity) emissions shall be measured by applicable reference methods, or equivalent or alternative methods approved by the cabinet (and U.S.EPA, if required), and shall not exceed the respective limitations specified herein..

2) Emissions Unit 01 and 02 shall be performance tested initially for compliance with the emission standards for PM/PM_{10}(filterable); sulfur dioxide (SO2); nitrogen oxides (NOx); and carbon monoxide (CO), by applicable reference methods, or by equivalent or alternative test methods approved by the cabinet and U.S. EPA.

3) Emissions Unit 01 and 02 shall be performance tested initially for compliance with the BACT emission standards for PM_{10}(condensable) and VOCs, by applicable reference method, or by method approved by the cabinet.

4) After the initial compliance test, and CEMS/COMs certification as stated above, continuing compliance with the emission standards shall be determined by continuous emission monitors for opacity, NO_x, CO and SO_2.

5) The permittee shall perform an optimization study to re-examine the 0.41 lb-SO_2/mmBtu 24-hour emission limit for emission units 1 and 2 after the initial compliance demonstration and two years of commercial operation of unit 1. The results of that study will be used to revise the 24-hour SO_2 limit with a target emission rate of 0.23 lb-SO_2/mmBtu using the following equation the new limit will be:

$$E = 1.10 \times \left[\left(\sum_{i=1}^{n} \left(\frac{X_n}{n} \right) \right) + \left(1.96 \times \left(\sqrt{\frac{\left(n \sum_{i=1}^{n} X_n^2 - \left(\sum_{i=1}^{n} X_n \right)^2 \right)}{n^2 (n-1)}} \right) \right) \right]$$

n =	Number of 24-hour data points
X_n =	24-hour Average Reading for data point n
E =	New 24-hour SO_2 Average Emission Limit

NOTE: under no condition shall the short term limit set for 24-hour SO_2 be adjusted up above 0.41 lb-SO_2/mmBtu.

SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F – MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS

1. When continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:
   a. Date, place as defined in this permit, and time of sampling or measurements.
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement;
   [Material incorporated by reference by 401 KAR 52:020, Section 1b (IV)1].

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality [Material incorporated by reference by 401 KAR 52:020, Sections 1b(IV) 2 and 1a(8)].

3. In accordance with the requirements of 401 KAR 52:020 Section 3(1)h the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:
   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;
   b. To access and copy any records required by the permit:
   c. Inspect, at reasonable times, any facilities, equipment (including monitoring and pollution control equipment), practices, or operations required by the permit. Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.
   d. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.
   e. Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit, other than continuous emission or opacity monitors, shall be submitted to the Division's Owensboro Regional Office at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during the previous six months because the emission unit was not in operation [Material incorporated by reference by 401 KAR 52:020, Section 1b (V)1].

SECTION F – MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

6. The semi-annual reports are due prior to January 30th and July 30th of each year. Data from the continuous emission and opacity monitors shall be reported to the Technical Services Branch in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All reports shall be certified by a responsible official pursuant to 401 KAR 52:020 Section 23. All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1 the owner or operator shall notify the Regional Office listed on the front of the permit concerning startups, shutdowns, or malfunctions as follows:

   a) When emissions during any planned shutdowns and ensuing startups will exceed the standards notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
   b) When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards notification shall be made as promptly as possible by telephone (or other electronic media) and shall submit written notice upon request.

8. The owner or operator shall report emission related exceedances from permit requirements including those attributed to upset conditions (other than emission exceedances covered by Section F.7. above) to the Regional Office listed in front of this permit within 30 days. Other deviations from permit requirements shall be included in the semiannual report required by Section F.6. Material incorporated by reference by 401 KAR 52:020, Section 1b V 3, 4.

9. Pursuant to 401 KAR 52:020, Permits, Section 21, the permittee shall certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:
   a. Identification of the term or condition;
   b. Compliance status of each term or condition of the permit;
   c. Whether compliance was continuous or intermittent;
   d. The method used for determining the compliance status for the source, currently and over the reporting period, and
   e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit.
   f. The certification shall be postmarked by January 30th of each year. Annual compliance certifications should be mailed to the following addresses:

SECTION F – MONITORING, RECORD KEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

Division for Air Quality
Owensboro Regional Office
3032 Alvey Park Dr. W.
STE 700
Owensboro, KY 42303-2191

U.S. EPA Region 4
Air Enforcement Branch
Atlanta Federal Center
61 Forsyth St.
Atlanta, GA 30303-8960

Division for Air Quality
Central Files
803 Schenkel Lane
Frankfort, KY 40601

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within thirty (30) days of the date the KEIS emission report is mailed to the permittee.

11. Pursuant to Section VII.3 of the policy manual of the Division for Air Quality as referenced in 401 KAR 50:016, Section 1(1), results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days after the completion of the fieldwork.

SECTION G – GENERAL PROVISIONS

(a) General Compliance Requirements

1. The permittee shall comply with all conditions of this permit. Noncompliance shall be a violation of 401 KAR 52:020 and of the Clean Air Act and is grounds for enforcement action including termination, revocation and reissuance, revision or denial of a permit [Material incorporated by reference by 401 KAR 52:020, Section 1a, 3].

2. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition [Material incorporated by reference by 401 KAR 52:020, Section 1a, 6].

3. This permit may be revised, revoked, reopened and reissued, or terminated for cause in accordance with 401 KAR 52:020, Section 19. The permit will be reopened for cause and revised accordingly under the following circumstances:
   a. If additional requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to 401 KAR 52:020, Section 12;
   b. The Cabinet or the U. S. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements;
   c. The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;
   d. If any additional applicable requirements of the Acid Rain Program become applicable to the source.

   Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the Division may provide a shorter time period in the case of an emergency.

4. The permittee shall furnish information upon request by the cabinet to determine if cause exists for modifying, revoking and reissuing, or terminating the permit; or compliance with the permit [Material incorporated by reference by 401 KAR 52:020, Section 1a, 7,8].

5. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such facts or corrected information to the permitting authority [Material incorporated by reference by 401 KAR 52:020, Section 7(1)].

SECTION G – GENERAL PROVISIONS (CONTINUED)

6. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit [Material incorporated by reference by 401 KAR 52:020, Section 1a, 14].

7. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance [Material incorporated by reference by 401 KAR 52:020, Section 1a, 4].

8. Except for requirements identified in this permit as state-origin requirements, all terms and conditions shall be enforceable by the United States Environmental Protection Agency and citizens of the United States [Material incorporated by reference by 401 KAR 52:020, Section 1a, 15)b].

9. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6). [Material incorporated by reference by 401 KAR 52:020, Section 1a, 10]

10. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance [401 KAR 52:020, Section 11(3)(b)].

11. This permit does not convey property rights or exclusive privileges [Material incorporated by reference by 401 KAR 52:020, Section 1a, 9].

12. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Kentucky Cabinet for Natural Resources and Environmental Protection or any other federal, state, or local agency.

13. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry [401 KAR 52:020, Section 11(3)(d)].

14. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders [401 KAR 52:020, Section 11(3)(a)].

15. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the owner or operator from enforcement actions for violating an applicable requirement prior to or at the time of permit issuance. Compliance with the conditions of a permit shall be considered compliance with:
    (a) Applicable requirements that are included and specifically identified in the permit and
    (b) Non-applicable requirements expressly identified in this permit.

SECTION G – GENERAL PROVISIONS (CONTINUED)

16. Pursuant to Section VII 2(1) of the policy manual of the Division for Air Quality as referenced by 401 KAR 50:016, Section 1(1), at least one month prior to the date of the required performance test, the permittee shall complete and return a Compliance Test Protocol (Form DEP 6027) to the Division's Frankfort Central Office and the Division's Technical Services Branch. Pursuant to 401 KAR 50:045, Section 5, the Division shall be notified of the actual test date at least ten (10) days prior to the test.

(b) Permit Expiration and Reapplication Requirements

1. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

2. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020 Section 8(2)].

(c) Permit Revisions

1. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the SIP or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

2. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements

1. Construction of process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

SECTION G – GENERAL PROVISIONS (CONTINUED)

2. Pursuant to 59:005, Section 3, within thirty (30) days following completion and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, with a copy to the Division's Frankfort Central Office, notification of the following:
   a. The date when construction commenced.
   b. The date of start-up of the affected facilities listed in this permit.
   c. The date when the maximum production rate specified in the permit application was achieved.

3. Pursuant to Regulations 401 KAR 52:020, Section 3(2), and 401 KAR 51:017, Section 17(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the cabinet may extend these time periods if the source shows good cause.

4. For those affected facilities for which construction is authorized by this permit, a source shall be allowed to construct with the proposed permit. Operational or final permit approval is not granted by this permit until compliance with the applicable standards specified herein has been demonstrated pursuant to 401 KAR 50:055. If compliance is not demonstrated within the prescribed timeframe provided in 401 KAR 50:055, the source shall operate thereafter only for the purpose of demonstrating compliance, unless otherwise authorized by Section I of this permit or order of the cabinet.

5. This permit shall allow time for the initial start-up, operation, and compliance demonstration of the affected facilities listed herein. However, within sixty (60) days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities, the permittee shall conduct a performance demonstration (test) on the affected facilities for particulate matter; sulfur dioxide (SO_2); nitrogen oxides (NO_x); carbon monoxide (CO); fluoride as HF; beryllium; Hydrogen Chloride (HCl); Arsenic (As); Chromium (Cr); Manganese (Mg); Lead (Pb); Cadmium (Cd); and Mercury (Hg), in accordance with 401 KAR 50:055, General compliance requirements. These performance tests must also be conducted in accordance with General Provisions G(d)6 of this permit and the permittee must furnish to the Division for Air Quality's Frankfort Central Office a written report of the results of such performance test.

6. Terms and conditions in this permit established pursuant to the construction authority of 401 KAR 51:017 or 401 KAR 51:052 shall not expire.

7. Pursuant to Section VII 2.(1) of the policy manual of the Division for Air Quality as referenced by 401 KAR 50:016, Section 1.(1), at least one month prior to the date of the

SECTION G – GENERAL PROVISIONS (CONTINUED)

required performance test, the permittee shall complete and return a Compliance Test Protocol (Form DEP 6027) to the Division's Frankfort Central Office. Pursuant to 401 KAR 50:045, Section 5, the Division shall be notified of the actual test date at least ten (10) days prior to the test.

(e) Acid Rain Program Requirements

1. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

2. The source shall comply with all requirements and conditions of the Title IV, Acid Rain Permit contained in Section J of this document and the Phase II permit application (including the Phase II NO_x compliance plan, if applicable) issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

(f) Emergency Provisions

1. Pursuant to 401 KAR 52:020 Section 24(1), an emergency shall constitute an affirmative defense to an action brought for the noncompliance with the technology-based emission limitations if the permittee demonstrates through properly signed contemporaneous operating logs or relevant evidence that:
   a. An emergency occurred and the permittee can identify the cause of the emergency;
   b. The permitted facility was at the time being properly operated;
   c. During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and
   d. Pursuant to 401 KAR 52:020, 401 KAR 50:055, and KRS 224.01-400, the permittee notified the Division as promptly as possible and submitted written notice of the emergency to the Division within two working after the time when emission limitations were exceeded due to the emergency. The notice shall include a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.
   e. This requirement does not relieve the source from other local, state or federal notification requirements.

2. Emergency conditions listed in General Condition (f)1 above are in addition to any emergency or upset provision(s) contained in an applicable requirement [401 KAR 52:020, Section 24(3)].

3. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof [401 KAR 52:020, Section 24(2)].

SECTION G – GENERAL PROVISIONS (CONTINUED)

(g) Risk Management Provisions

1. The permittee shall comply with all applicable requirements of 401 KAR 68, Chemical Accident Prevention. If required, the permittee shall comply with the Risk Management Program and submit a Risk Management Plan to:

   RMP Reporting Center
   P.O. Box 3346
   Merrifield, VA, 22116-3346

2. If requested, the permittee shall submit additional relevant information to the Division or the U.S. EPA.

(h) Ozone depleting substances

1. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:
   a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.
   c. Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.
   d. Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.
   e. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166.
   f. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.
   g. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

SECTION H – ALTERNATE OPERATING SCENARIO

None

SECTION I – COMPLIANCE SCHEDULE

None

SECTION J – ACID RAIN

TITLE IV PHASE II ACID RAIN

ACID RAIN PERMIT CONTENTS

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NOx requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4) The permit application submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the Phase II Application.

5) Summary of Actions

- Statement of Basis:

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100 and Titles IV and V of the Clean Air Act, the Kentucky Natural Resources and Environmental Protection Cabinet, Division for Air Quality issues this permit pursuant to Regulations 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, and Federal 40 CFR Part 76.

SECTION J – ACID RAIN

PERMIT (Conditions)

Plant Name: Thoroughbred Generating Station
Affected Unit: 01

- SO_2 Allowance Allocations and NO_x Requirements for the affected unit:

SO_2 Allowances	Year				
	2002	2003	2004	2005	2006
Tables 2, 3 or 4 of 40 CFR Part 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO2 allowance per USEPA Acid Rain Program

** This unit currently does not have applicable NO_x limits set by 40 CFR, part 76.

SECTION J – ACID RAIN

PERMIT (Conditions)

Plant Name: Thoroughbred Generating Station
Affected Unit: 02

- SO_2 Allowance Allocations and NO_x Requirements for the affected unit:

SO_2 Allowances	Year				
	2002	2003	2004	2005	2006
Tables 2, 3 or 4 of 40 CFR Part 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO2 allowance per USEPA Acid Rain Program

** This unit currently does not have applicable NO_x limits set by 40 CFR, part 76.

SECTION J – ACID RAIN

PERMIT (Conditions)

- Comments, Notes, and Justifications:

  The two (2) pulverized coal fired boilers, units 01 and 02 will be constructed after the SO_2 allocation date; therefore these units will have no SO_2 allowances allocated by U.S. EPA and must obtain offsets.

  The two (2) pulverized coal fired boilers, units 01 and 02 do not have applicable NO_x limits set by 40 CFR part 76.

- Permit Application: Attached
  The Phase II Permit Application is a part of this permit and the source must comply with the standard requirements and special provisions set forth in the Phase II Application.

- Summary of Actions:

  Previous Action:

  Draft Permit has been advertised for public comment.

  Present Action:

  Final permit issued

SUMMARY OF AIR TOXICS EMISSIONS TESTING AT SIXTEEN UTILITY POWER PLANTS

Prepared for
U.S. Department of Energy
Pittsburgh Energy Technology Center

Prepared Under
Burns and Roe Services Corporation
Contract No. DE-AC22-94PC92100
Subtask 44.02

July 1996

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Prepared by
Adrian Radziwon and Edward Winter
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July 1996

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SECTION 1.0 INTRODUCTION

Background

The U.S. Department of Energy performed comprehensive assessments of toxic emissions from nine selected coal-fired electric utility units. A similar assessment was also carried out at seven power plants which are hosts to demonstration projects carried out under the Clean Coal Technology Program. These data are being collected in response to the Clean Air Act Amendments of 1990, which require that EPA conduct a study of the emissions of hazardous air pollutants (HAPs) from electric utility power plants, and that these emissions be evaluated for potential health risks. The data have been compiled and combined with similar data collected as part of the Field Chemical Emissions Monitoring program sponsored by the Electric Power Research Institute (EPRI) and furnished to the U.S. Environmental Protection Agency for emissions factor and health risk determinations.

The assessments of emissions involve the collection and analysis of samples from all major input and output streams of the selected power plants for selected hazardous pollutants contained in Title III of the Clean Air Act.

Objectives

The specific objectives of this program were:

- To collect and subsequently analyze representative solid, liquid, and gas samples of all specified input and output streams of the selected power plants for selected hazardous air pollutants listed in Title III of the 1990 Clean Air Act Amendments and to assess the potential level of release (concentration) of these pollutants;

- To determine the removal efficiencies of pollution control subsystems for selected pollutants at the power plants;

- To determine material balances for selected pollutants in specified subsystems of the power plant and an overall material balance for the power plants;

- To determine the concentration as a function of particle size of the pollutants associated with the particulate fraction of the flue gas streams;

- To determine the concentration of the pollutants associated with the particulate and vapor-phase fractions of the specified flue gas streams;

- To determine the concentrations of toxic substances on the surfaces of fly ash particles;

- To provide data for EPA for use in risk assessments and in updating publication AP-42;

- To determine hexavalent chromium stack emissions at selected plants; and

- To compare Method 29 vapor-phase mercury results with those obtained via charcoal absorption.

Scope of This Report

Table 1-1 lists the chemical substances analyzed during this project. Not all of these compounds were measured at each power plant.

Report Structure

These results are reported in two sections. First (Section 2), corresponding data for each of the plants are presented in a way to allow comparisons to be made easily. Including:

- Select information about equipment and operation of each plant.
- Coal analyses: ultimate, trace metals, and anions.
- Stack concentration of trace elements.
- Overall ranges of removal efficiencies.

Second (Section 3), more specific data for each individual plant are presented separately. Including

- Description of each plant, with flowsheet.
- Flow rates of trace metals at various locations in the plants.
- Distribution of trace metals in the output streams.
- Removal efficiencies of the control devices.
- Temperatures at various points in the plant.

Uncertainties

Emission factors, removal efficiencies, and other results presented in this report rely on measurement data that vary with time and/or may be near the limit of detection or below it for many of the

Table 1-1 Target Analysis

Trace Elements

Antimony
Arsenic
Barium
Beryllium
Boron
Cadmium
Chromium total
Cobalt
Copper
Lead
Manganese
Mercury
Molybdenum
Nickel
Selenium
Vanadium

Radionuclides

Hexavalent Chromium

Mercury Speciation/Comparison

Anions

Chloride (HCl)
Fluoride (HF)
Sulfates
Phosphates

Reduced Species

Ammonia
Cyanide

Organics

Formaldehyde
Dioxins
Furans

Volatile Organics

Benzene
Bromoform
Carbon Disulfide
Carbon Tetrachloride
Chlorobenzene
Chloroform
1,4-Dichlorobenzene
cis-,1,3-Dichloropropene
trans-1,3-Dichloropropene
Ethyl Benzene
Ethyl Chloride (Chloroethane)
Ethylene Dichloride (1,2,-Dichloroethane)
Ethylidene Dichloride (1,1-Dichloroethane)
Methyl Bromide (Bromomethane)
Methyl Chloride (Chloromethane)
Methyl Chloroform (1,1,1-Trichloroethane)
Methyl Ethyl Ketone (2-Butanone)
Methylene Chloride (Dichloromethane)
Propylene Dichloride (1,2-Dichloropropane)
Styrene
1,1,2,2-Tetrachloroethane
Tetrachloroethene
Toluene
1,1,2-Trichloroethane
Trichloroethene
Vinyl Acetate
Vinyl Chloride
Vinylidene Chloride (1,1-Dichloroethene)
m,p-Xylene
o-Xylene

Semivolatile Organics

Acenapthene
Acenaphthalene
Acetophenone
4-Aminobiphenyl
Aniline
Anthracene
Benzidine
Benzo(a)anthracene
Benzo(a)pyrene
Benzo(b)fluoranthene
Benzo(g,h,i)perylene
Benzo(k)fluoranthene
Benzoic Acid
Benzyl Alcohol
Indeno(1,2,3-cd)pyrene
Isophorone
Methyl Methanesulfonate
3-Methylchloianthrene
2-Methylnaphthalene
2-Methylphenol (o-cresol)
4-Methylphenol (p-cresol)
N-Nitroso-di-n-butylamine
N-Nitrosodimethylamine
N-Nitrosodiphenylamine
N-Nitrosopropylamine
N-Nitrosopiperidine
Naphthalene
1-Naphthylamine
7,12-Dimethylbenz(a)anthracene
Dimethylphenethylamine
2,4-Dimethylphenol
Dimethylphthalate
4,6-Dinitro-2-methylphenol
2,4-Dinitrophenol
2,4-Dinitrotoluene
2,6-Dinitrotoluene
Diphenylamine
1,2-Diphenylhydrazine
Ethyl Methanesulfonate
2-Nitrophenol
4-Nitrophenol
Pentachlorobenzene

Table 1-1 (Continued)

Semivolatile Organics (continued)

4-Bromophenyl Phenyl Ether
Butylbenzylphthalate
4-Chloro-3-Methylphenol
p-Chloraniline
bis(2-Chloroethoxy)methane
bis(2-Chloroethyl)ether
bis(2-Chloroisopropyl)ether
1-Chloronaphthalene
2-Chloronaphthalene
2-Chlorophenol
4-Chlorophenyl Phenyl Ether
Chrysene
bis(2-Ehtylhexyl·)phthalate
Fluoranthene
Fluorene
Hexachlorobenzene
Hexachlorobutadiene
Hexachlorocyclopentadiene
Hexachloroethane
2-Naphthylamine
2-Nitroaniline
3-Nitroaniline
4-Nitroaniline
Nitrobenzene
Di-n-octylphthalate
Dibenz(a,h)anthracene
Dibenz(a,j)acridine
Dibenzofuran
Dibutylphthalate
1,2-Dichlorobenzene
1,3-Dichlorobenzene
1,4-Dichlorobenzene
3,3'-Dichlorobenzidine
2,4-Dichlorophenol
2,6-Dichlorophenol
2,6-Dichlorophenol
Diethylphthalate
p-Dimethylaminoazobenzene
Pentachloronitrobenzene
Pentachlorophenol
Phenacetin
Phenanthrene
Phenol
2-Picoline
Pronamide
Pyrene
Pyridine
1,2,4,5-Tetrachlorobenzene
2,3,4,6-Tetrachlorophenol
1,2,24-Trichlorobenzene
2,4,5-Trichlorophenol
2,4,6-Trichlorophenol
2-Fluorobiphenyl
2-Fluorophenol
Nitrobenzene
Phenol
Terphenyl
2,4,6-Tribromophenol

Additional Elements

Aluminum
Calcium
Iron
Magnesium
Potassium
Sodium
Silicon
Strontium
Titanium
Zinc
Uranium (coal only)
Thorium (coal only)

substances of interest. In this summary report, highly uncertain results have been flagged in the tables. For a more comprehensive examination of uncertainties associated with this data, the reader is referred to a companion report, "A Comprehensive Assessment of Toxic Emissions from Coal-Fired Power Plants: Statistical Correlations from the Combined DOE and EPRI Field Test Data" or the complete testing reports for each power plant listed in the Appendix.

SECTION 2.0 EXECUTIVE SUMMARY

This report is a summary of sixteen separate test projects sponsored by the U.S. Department of Energy in collaboration with the Electric Power Research Institute. Its purpose is to present, in a concise form, the results of those tests. To the maximum extent possible, results were taken directly from the reports. Calculations were performed only when necessary for the sake of comparison.

A summary of the results is presented in the following tables. These results are organized to allow plant-by-plant comparisons. Compounds that could have been measured by the techniques used but were not detected are not included in this report. If more information is needed, the reader is asked to consult the individual reports for each power station.

Table 2-1 summarizes information about each plant. Table 2-2 lists the conventions used by each contractor for reporting volumetric gaseous data. Table 2-3 presents the ultimate analyses for the feed coals at the test sites while Table 2-4 presents the coal analyses for minor and trace elements. Emission factors are presented in Tables 2-5 and 2-6 for organic materials and for trace/minor elements, respectively. Table 2-7 presents the stack concentrations of trace elements. Tables 2-8.1 and 2-8.2 show the range and average of trace element removal efficiencies at the test sites equipped with particulate removal devices. These data are shown graphically in Figures 2-1, 2-2, and 2-3. Finally, Table 2-9 summarizes the sampling and analytical procedures used at each site.

Non-Detects

Non-detects are samples in which the particular chemical compound being analyzed for was not detected. In a great many instances,

the compounds of interest were present in the samples at concentrations near, at, or below the limits of the analytical procedures to detect them. When a compound is not detected, it is uncertain whether it is present or not. A non-detect does not guarantee that the compound in question is absent. If it is present in the sample, it is at a concentration below the detection limit of the measurement technique.

In some cases, where multiple samples were taken or multiple analyses were conducted on the same sample, a combination of non-detects and measurable results was observed. A convention was adopted to interpret data that included non-detects. This convention is used in the majority of the sixteen reports summarized here. The method used is described below and those plants that used different or unspecified methods are identified.

The commonly used method for handling non-detects in calculating emission rates and material balances is:

- If there are no non-detects, then the arithmetic average of the three or four samples is used.

- If there are both measurable quantities and non-detects, then one-half the detection limit is used for the non-detects in calculating averages. However, if the resulting average is calculated to be less than the highest detection limit, then the value is reported as "less than" the highest detection limit.

- If all values are non-detects, then the average is reported as "less than" the average of the detection limits.

Most of the reports used these conventions. Two exceptions are Plant Smith and Nelson Dewey Station. A description of the manner in which non-detects were handled was not found in the Smith

report. In the Nelson Dewey report, mass balance calculations involving non-detects were carried out using the detection limit for the value.

In the tables that follow, flags are used to classify the data. The flags and their definitions are:

All samples used to calculate the average shown are non-detects. That is, the compound was not observed in any of the measurements.

A One of the samples is a non-detect, and measurable quantities were observed for the others.

B Two of the samples are non-detects and at least one measurable quantity was observed.

C More than two non-detects observed. When three samples are being reported using an average value, as many as six results could be involved in determining the average value. For example, in some samples, the entrained particulate phase and the gas phase were analyzed separately providing two results for each sample.

Uncertainty Analysis

Collecting and analyzing stream samples in an operating power plant is very difficult. Load changes and natural variations in operation result in changing conditions over the duration of the test, which normally require several hours to complete. Because of this variability, similar runs on different days would not be expected to be exact replicates. Therefore, the limits of uncertainty have been calculated for emission factors and some of the other results. The technique used is described in the publication, ANSI/ASME PTC 19.1 - 1985, "Measurement Uncertainty."

The result is a 95 percent confidence interval based on the standard deviation of the samples and the Student's "t" probability distribution function.

Uncertainty analyses were carried out in the same fashion in the majority of the reports. Two exceptions were Plant Smith and Nelson Dewey Station. In the Smith report, uncertainty appears to be simply the standard deviation of the three sample values. In the Nelson Dewey report, no description of Uncertainty Analysis was found.

In the tables in Section 2, rather than list the calculated uncertainty values from the original reports, uncertainties greater than 100 percent have been flagged as follows:

U Values with uncertainties greater than ±100 percent. For example, if a value of 10 is flagged, the true value is expected to lie somewhere within a range equal to or greater than 0-20, 95 percent of the time, for runs made at the same operating conditions.

N An uncertainty limit is either not known or not calculated.

Table 2-1 Power Plant Descriptions

Power Plant	Operator	Contractor	Boiler Type	Size, MWe	Coal	Control Technology		
						SO_2	NO_x	Particulates
Coal Creek	Cooperative Power	Battelle	Tangential-Fired	550	Lignite	Lime Scrubber	Over-Fire Air	ESP
Boswell	Minnesota Power	Weston	Drum	69	Subbituminous	None	None	Baghouse
Springerville	Tucson Electric Co.	Southern Research Institute	Corner-Fired	397	Subbituminous	Spray Dryer Absorber	Over-Fired Air	Baghouse
Cardinal	Ohio Power Co.	Energy and Environmental Corp.	Cell Burner	615	Bituminous	None	None	ESP
Baldwin	Illinois Power	Weston	Cyclone	568	Bituminous	None	None	ESP
Niles	Ohio Edison	Battelle	Cyclone	108	Bituminous	None	None	ESP
SNOX (Niles)	Asea Brown Boveri	Battelle	Cyclone	35 (A)	Bituminous	Catalytic System (B,C)	SCR	Baghouse
Yates	Georgia Power	Radian	Tangential-Fired	100	Bituminous	Limestone Scrubber (C,D)	None	ESP
Bailly	Northern Indiana Public Serv Co.	Southern Research Institute	Cyclone	528	Bituminous	Advanced FGD (C,E)	None	ESP
Nelson Dewey	Wisconsin Power & Light	Acurex Environmental Corp.	Cyclone	100	Bituminous	None	Reburn (C)	ESP
Hammond	Southern Company Services	Radian	Opposed Wall-Fired	500	Bituminous	None	Low-NO_x Burners	ESP
Smith	Southern Company Services	Southern Research Institute	Tangential-Fired	196	Bituminous	None	Low-NO_x Burners (C)	ESP
Burger	Babcock & Wilcox	Radian	Wall-Fired	160	Bituminous	SNRB (C,F)	SNRB	Baghouse ESP
Arapahoe	Public Service Co. of Colorado	Carnot	Roof-Fired	117	Bituminous	None	Low-NO_x Burners Over-Fire Air SNCR (C,G)	Baghouse
TIDD	Ohio Power	Radian	Pressurized Fluidized Bed	70	Bituminous	Hot Gas Cleanup (C)	None	ESP
GSA Pilot Plant (Shawnee)	AirPol Inc.	Energy and Environmental Research Corp.		10 (H)	(Slipstream reconstituted) (I)	Gas Suspension Absorption (C)	None	ESP and/or Baghouse (J)

A. Slipstream from Niles unit
B. Converts SO_2 and SO_3; removed as sulfuric acid
C. Innovative Clean Coal Technology Project
D. Chiyoda Wet Limestone Scrubber
E. Pure Air's Wet Limestone Scrubber
F. SOx-NOx-ROx-BOx Process
G. Selective Non-Catalytic Reduction
H. Slipstream from Shawnee Unit
I. Feed to GSA unit: Some removed flyash was reinjected to simulate composition of the flue gas stream leaving the boiler
J. Can be configured either as series or parallel flow

Table 2-2 Definition of Normal and Standard Volumetric Units for Each Plant

Pressure is 1.0 atmosphere for all plants			
	Nm^3	dscm	dscfm
Coal Creek	Dry, 0°C, 3% O2	Dry, 20°C	
Boswell	0°C		Dry
Springerville	Dry, 20°C, 3% O2		Dry, 0°C
Cardinal	0°C	Dry, 20°C	
Baldwin	0°		Dry
Niles	Dry, 0°C, 3% O2		
SNOX	Dry, 0°C, 3% O2	Dry, 20°C	
Yates	0°C		Dry, 20°C
Bailly	Dry, 20°C, 3% O2		Dry, 0°C
Nelson Dewey			
Hammond	Dry, 0°C		Dry, 20°C
Smith	4% O2		
Burger	0°C		Dry, 15.6°C
Arapahoe	Dry, 0°C		Dry, 20°C
TIDD	0°C		Dry, 20°C
GSA (Shawnee)	0°C	Dry, 20°C	

Nm^3: Normal cubic meters
dscm: Dry standard cubic meters
dscfm: Dry standard cubic feet per minute

Table 2-3 Average Coal Analyses for Plants

	Coal Creek	Boswell	Springerville	Cardinal	Baldwin	Niles	SNOX	Yates	Bailly
Analysis, Weight Percent									
Carbon	50.85	51.33	55.23	69.24	59.39	67.12	67.68	72.0	61.21
Hydrogen	3.36	3.50	4.35	5.61	4.12	4.47	4.51	4.83	4.45
Nitrogen	0.76	0.72	1.0	0.81	1.11	1.40	1.41	1.52	1.05
Sulfur	0.86	0.70	0.64	3.11	2.88	2.61	2.44	2.74	3.15
Oxygen	15.51	10.53	11.07	8.54	7.23	6.71	6.77	7.74	9.32
Chlorine		0.000028	0.039	0.08	0.07			0.14	0.1
Fluorine		0.000028	0.0073	<0.01	0.000097			0.01	0.0094
Ash	14.65	8.39	22.18	11.2	10.23	11.19	11.28	11.1	10.36
Moisture	14.00	24.82	5.53	1.4	14.97	6.5	5.9	0	10.35
Total	100.00	100.00	100.05	100.01	100.00	100.00	100.00	99.93	100.00
HHV, Btu/lb	8,203	10,474	9,814	11,964	10,626	12,090	12,258	12,697	11,103

Table 2-3 Average Coal Analyses for Plants, (continued)

	Nelson Dewey		Hammond		Smith		Burger
	Baseline	Reburn	OFA*	LNB*	Baseline	Low NO_x	SNRB*
Weight, Percent							
Carbon	61.41	62.86			65.90	67.12	
Hydrogen	4.33	4.45			4.40	4.54	
Nitrogen	1.10	1.02			1.37	1.46	
Sulfur	1.47	1.32	1.5	1.6	2.90	2.85	3.4
Oxygen	8.78	10.06			6.46	6.50	
Chlorine					0.19	0.17	
Fluorine					0.0080	0.0059	
Ash	7.32	7.82	9.5	9.1	9.05	8.29	12.0
Moisture	15.59	12.48	4.7	3.8	9.83	9.24	2.05
	100.00	100.01			100.09	100.18	
HHV, Btu/lb	11,387	11,688	13,056	13,276	11,882	12,062	12,620

*OFA = Over-fire Air
LNB = Low NO_x Burner
SNRB = SO_x, NO_x, RO_x, BO_x

Table 2-3 Average Coal Analyses for Plants, (continued)

	Arapahoe Plant		TIDD Plant	AirPol GSA Shawnee Plant			
				Series		Parallel	
	Baseline	SNCR*		Baseline	Demo	Baseline	Demo
Weight, Percent							
Carbon	62.88	65.10		63.9	64.8	65.8	64.8
Hydrogen	4.41	4.57		4.7	4.7	4.8	4.4
Nitrogen	1.59	1.66		1.2	1.3	1.3	1.3
Sulfur	0.43	0.44	3.4	2.6	2.6	2.5	2.6
Oxygen	10.67	10.04		4.9	5.3	6.1	6.0
Ash	8.81	8.58	12.0	11.4	11.2	9.5	12.0
Moisture	11.2	9.6		11.2	10.0	10.0	9.0
Total	100.000	100.000		99.9	99.9	100.0	100.1
HHV, Btu/lb	12,565	12,638	12,700	11,244	11,516	11,779	11,518

*Selective Non-Catalytic Reduction

Table 2-4 Average Coal Analyses for Plants - Trace Elements

	Coal Creek	Boswell	Springerville	Cardinal	Baldwin	Miles	SNOX	Yates	Bailly
Minor/Trace Elements, ppm									
Antimony	ND< 37 #	0.37	1.5 B	21 A	0.49	1.1	0.9	0.61	0.64
Arsenic	9.4	1.4	2.9	13	2.6	33	34	2.3	2.8
Barium	330	320	321	22	51	55	63	80	42
Beryllium	0.67	0.18	1.1	1.3	1.0	1.9	2.3	1.1	1.7
Boron	140	230	100	96	160	72	53	100	201
Cadmium	ND< 0.9 #	0.06	ND< 0.5 #	0.12	0.54	ND< 0.3 #	ND<0.3 #	0.30	2.7
Chromium	8.2	3.2	9.2	18	25	16	15	25	42
Cobalt	2.2	1.0	3.5	4.4 A	3.1	6.3	5.4	3.5	2.5
Copper	7.0	5.2	13	8.9	8.3	15	14	36.0 AU	9.4
Lead	7.3	3.9	ND< 5.0 #	6.6	9.3	13	13	8.0	7.6
Manganese	97	102	81	56	40	25	27	23	29
Mercury	0.08	0.05	0.037	0.048	0.06	0.21	0.26	0.077	0.10
Molybdenum	2.3	4.1	2.2	3.2 A	6.2	ND< 3 B	ND< 3 A	22	7.2
Nickel	2.6	2.1	5.7	14	16	18	15	30	23
Selenium	ND< 1.3 #	0.66	0.86 A	23	3.2	ND< 0.6 #	0.90	2.3	1.3
Vanadium	15	6.3	27	32	29	28	26	39	48
Chloride								1,400	1,000
Fluoride								100	94
Sulfate									
Phosphorus		103			120			84	119

ND< Value shown is detection limit.
Of the calculations contributing to the average value shown, all include a non-detect measurement.
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B Of the calculations contributing to the average value shown, two include a non-detect measurement.
U Uncertainty (= 95% Confident Limit): Equal to or greater than 100 percent of value.
N Uncertainty limit not known or not calculated.

Table 2-4 Average Coal Analyses for Plants - Trace Elements, (continued)

	Nelson Dewey		Hammond		Smith		Burger
	Baseline	Reburn	OFA	LNB	Baseline	Low NO_x	
Minor/Trace Elements, ppm							
Antimony			1.4	1.5	1.2	1.5	ND< 1.0 #
Arsenic	10	7.1	17	23	4.2	3.6	5.0
Barium			170	99	54	57	47
Beryllium	3.1	2.9	1.4	2.2	ND< 10	ND< 10	0.67
Boron							
Cadmium	32.0 A	41.0 A	ND< 0.11 BN	ND< 2.6 #	ND< 2	2.0	ND< 0.3 #
Chromium	9.4	8.2	22	17	17	17	15
Cobalt			8.3	6.1	3.0	2.5	2.3
Copper			38	34	14	13	
Lead	31	14	5.1	7.3	18	20	5.3
Manganese	22	24	17	14	33	16	19
Mercury	ND< 0.10 #	ND< 0.10 #	0.15	0.14	0.064	0.077	0.13
Molybdenum			3.2 AU	ND< 3.6 AN	8.6	11	
Nickel	23	40	27	17	6.7	6.8	8.0
Selenium	ND< 1.0 #	ND< 1.0 #	3.8	3.7	2.3	1.6	2.7
Vanadium			37	26	53	78	22
Chloride	29 C	45 C	410	340			370
Fluoride	ND< 4.4 #	ND< 3.4 #	70	91			70
Sulfate							
Phosphorus			240	140	92	73	

ND< Value shown is detection limit.
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U Uncertainty (= 95% Confident Limit): Equal to or greater than 100 percent of value.
N Uncertainty limit not known or not calculated.

Table 2-4 Average Coal Analyses for Plants - Trace Elements, (continued)

	Arapahoe		TIDD Plant	AirPol GSA, Shawnee			
				Series		Parallel	
	Baseline	SNCR		Baseline	Demo	Baseline	Demo
Minor/Trace Elements, ppm							
Antimony			0.48	ND 0.5	ND 0.5	ND 0.5	ND 0.05
Arsenic	0.48	0.64	45	4.0	4.0	5.0	5.0
Barium	419	339	54	115	612	58	64
Beryllium	0.22	0.55 U	1.6	0.6	1.1	0.8	1.1
Boron			55.0 AU				
Cadmium	ND<0.05 BN	<0.06 BN	0.11 U	0.04	0.1	0.09	ND 0.05
Chromium	1.1	1.4 U	16	14	17	16	17
Cobalt	0.9	1.3	3.9	4.0	4.0	4.0	5.0
Copper	2.7	3.7	7.0				
Lead	2.1	2.2	6.3	4.0	5.0	5.0	5.0
Manganese	4.2	5.2	26	17	32	31	24
Mercury	0.021	0.019 U	0.15	0.075	0.065	0.075	0.065
Molybdenum	0.1 BU	0.5	0.58				
Nickel	0.6	1.0	13	9.0	7.0		12
Selenium	0.82	1.5 U	1.8	1.0	3.0	2.0	2.0
Vanadium	3.0	4.3	24	26	29	30	47
Chloride	22	16.0 N	1,200	200	200	200	200
Fluoride	84		110				
Sulfate							
Phosphorus	410	317	96				

ND< Value shown is detection limit.
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U Uncertainty (= 95% Confident Limit): Equal to or greater than 100 percent of value.
N *Uncertainty limit not known or not calculated.*

Table 2-5.1 Emission Factors, Aldehydes and Ketones

	Coal Creek	Boswell	Springerville	Cardinal	Baldwin	Niles	SNOX	Yates	Bailly
				Non Soot Blowing	Non Soot Blowing				
Units: $lb/10^{12}$ Btu									
Acetone	NC	1100. BU		31. BN	ND< 1.0 #	NC	NC		8.4 AN
Acetaldhyde	67.	ND< 1.1 #	ND< 0.4 #	ND < 4.8 AN	14	89. U	390	8.6 U	ND< 0.89 AN
Acrolein	ND<2.2 #	ND< 3.4 A			3.5 U	41. U	8.3		
Benzaldehyde		5.8 U			16				
2,5-Dimethyl benzaldehyde		15. AU			14				
n-Butyraldehyde		19. AU			ND< 7.2 A				
2-Butanone (Methyl ethyl ketone)	9.8 U	ND< 5.0 #		48. BN	3.7 U	5.1 BU	ND< 8.3 #		
Crotonaldehyde		ND< 7.1 #			ND< 6.3 B				
Formaldehyde	ND<1.8 BU	ND< 1.7 #	1.4 BN	60. AN	ND< 1.7 BU	3.9 AU	57	24. U	11. N
Hexaldehyde		ND< 6.6 B			9.9				
2-Hexanone	12. U					7.8 BU	19. AU		
4-Methyl-2-Pentanone	6.0 BU					ND< 5.0 BU	ND< 5.8 #		
Propanal (Propionaldehyde)	12. U	ND< 1.7 #			6.0 BU	25. U	13. U		
o-Tolualdehyde		ND< 2.0 #			8.7 AU				
m/p-Tolualdehyde		1.8 A			5.8				
Valeraldehyde		11. BU			5.2 U				
iso-Valeraldehyde		ND< 4.6 #			ND< 4.0 #				
1,4-Benzoquinone				ND< 5.2 #					

ND< Value shown is detection limit.
\# Of the calculations contributing to the average value shown, all include a non-detect measurement.
A Of the calculations contributing to the average value shown, one includes a non-detect measurement.
B Of the calculations contributing to the average value shown, two include a non-detect measurement.
U Uncertainty (= 95% Confidence Limit): Equal to or greater than 100 percent of value.
N Uncertainty limit not known or not calculated.
NC Not calculated.

Table 2-5.1 Emission Factors, Aldehydes and Ketones, (continued)

	Nelson Dewey		Hammond		Smith		Burger	
	Baseline	Reburn	OFA	LNB	Baseline	Low NO_x	Baseline	SNRB
Units: $lb/10^{12}$ Btu								
Acetone						4.1 N		
Acetaldhyde	2.7 BN	ND< 2.5 #	ND< 4.8 AN	4.3 U				
Acrolein			ND< 5.8 #					
Benzaldehyde								
2,5-Dimethyl benzaldehyde								
n-Butyraldehyde								
2-Butanone (Methyl ethyl ketone)								
Crotonaldehyde								
Formaldehyde	2.0 BN	ND< 2.5 #	ND< 4.0 BN	1.3 U		7.8 N		
Hexaldehyde								
2-Hexanone								
4-Methyl-2-Pentanone								
Propanal (Propionaldehyde)								
o-Tolualdehyde								
m/p-Tolualdehyde								
Valeraldehyde								
iso-Valeraldehyde								
1,4-Benzoquinone								

ND< Value shown is detection limit.
Of the calculations contributing to the average value shown, all include a non-detect measurement.
A Of the calculations contributing to the average value shown, one includes a non-detect measurement.
B Of the calculations contributing to the average value shown, two include a non-detect measurement.
U Uncertainty (= 95% Confidence Limit): Equal to or greater than 100 percent of value.
N Uncertainty limit not known or not calculated.