APPENDIX B
EMISSIONS CALCULATIONS

Appendix B

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BOWIE POWER STATION

Type of Equipment	Number	Size	Units	Capacity Factor/hours of operation for Each Piece of Equipment	Units	
GE Frame 7FA Model 4 Natural Gas-Fired Combined Cycle Combustion Turbines	2	3469.12	mmBtu/hour (HHV) both			
		1735	mmBtu/hour (HHV) each	95%		Maximum heat input for both turbines divided by 2
Duct Burners	2	420	mmBtu/hour (HHV)	4224	hours	
Natural Gas-Fired Auxiliary Boilers	1	50	mmBtu/hour	450	hours	
Diesel-Fired Fire Pumps	1	260	horsepower	100	hours	Hours limit from 40 CFR 60.4211(f)(2)
Cooling Tower	1	9	cells/tower	100%		
		127,860	gallons/min circulating rate			
Evaporation Pond	1	127	gallons/min max cooling tower blowdown	100%		
		4	gallons/min stormwater			
		131	gallons/min			Maximum cooling tower blowdown + stormwater
Circuit Breakers Containing SF_6	5					

Turbine and Duct Burner volatile HAP emissions control	70%

Fuel Data

Fuel	Heat Content		Sulfur Content		
Natural Gas	1035	Btu/scf	0.75	grains/100 scf	from El Paso Corporation
Diesel Fuel	137,000	Btu/gallon	15	ppm	Diesel BTU content from AP-42, Appendix A, Page A-5 Diesel sulfur content required by 40 CFR Subpart IIII 60.4207(b) which refers to 80.510(b)

Kiewit Power Engineers -- SWPG Bowie

2x1 7FA.04 Combined Cycle

Estimated Performance -- Option A4 (New and Clean) with GE 7FA.04 CTGs -- updated Dec. 2012

Model Revision: GC561-12062012-1 BJScrivner

1997 Steam Tables

		10F			59F			102F			With Duct Firing		
Case Name		Case A4b-41	Case A4b-21	Case A4b-1	Case A4b-44	Case A4b-24	Case A4b-4	Case A4b-49	Case A4b-29	Case A4b-9	Case A4b-11	Case A4b-14	Case A4b-19
Ambient Temp (F)		10	10	10	59	59	59	102	102	102	10	59	102
% Full Load		64	80	100	50	80	100	61	80	100	100	100	100
HRSG Firing/DB Exit Temperature		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Fired	Fired	Fired
CTG Model		GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04	GE 7FA.04
Gross CTG Output (each)	kW	112,200	141,400	176,700	79,200	126,800	161,856	80,800	106,300	148,000	176,700	161,856	148,000
Gross CTG Output (total)	kW	224,400	282,800	353,400	158,400	253,600	323,713	161,600	212,600	296,000	353,400	323,713	296,000
CTG Heat Input (HHV) (total)	MMBtu/h	2,516.42	2,895.28	3,469.12	2,041.60	2,670.88	3,231.74	2,041.62	2,386.46	3,023.86	3,469.12	3,231.74	3,023.86
Gross Cycle Heat Rate (LHV)	Btu/kWh	6,263	6,059	6,008	6,506	6,026	5,929	6,445	6,146	5,978	6,312	6,297	6,369
Gross Cycle Heat Rate (HHV)	Btu/kWh	6,947	6,721	6,664	7,216	6,684	6,576	7,149	6,817	6,631	7,002	6,984	7,064
Gross Cycle Efficiency (LHV)		54.5%	56.3%	56.8%	52.4%	56.6%	57.6%	52.9%	55.5%	57.1%	54.1%	54.2%	53.6%
Gross Cycle Efficiency (HHV)		49.1%	50.8%	51.2%	47.3%	51.1%	51.9%	47.7%	50.1%	51.5%	48.7%	48.9%	48.3%
Net Plant Output w/ Step-Up Xfmr Losses	kW	351,310	419,130	508,380	271,460	387,450	478,693	274,090	338,200	443,520	600,340	567,713	531,890
Net Plant Heat Rate (LHV) w/ Step-Up Xfmr Losse	Btu/kWh	6,458	6,228	6,152	6,780	6,215	6,087	6,715	6,362	6,147	6,471	6,466	6,549
Net Plant Heat Rate (HHV) w/ Step-Up Xfmr Losse	Btu/kWh	7,163	6,908	6,824	7,521	6,893	6,751	7,449	7,056	6,818	7,178	7,172	7,264
Net Plant Efficiency (LHV)		52.8%	54.8%	55.5%	50.3%	54.9%	56.1%	50.8%	53.6%	55.5%	52.7%	52.8%	52.1%
Net Plant Efficiency (HHV)		47.6%	49.4%	50.0%	45.4%	49.5%	50.5%	45.8%	48.4%	50.0%	47.5%	47.6%	47.0%
Circulating Water from Cooling Tower	Flow, lb/h	63,949,284	63,968,276	63,953,072	63,902,340	63,893,252	63,884,336	63,782,232	63,778,016	63,771,116	63,941,172	63,857,352	63,751,184
	Flow, gpm	127,815	127,811	127,814	127,825	127,827	127,829	127,853	127,854	127,855	127,817	127,836	127,860
Tower Blowdown	Flow, lb/h	16,623	17,332	20,924	25,273	28,964	32,843	42,123	44,608	48,921	31,400	46,508	63,547
	Flow, gpm	33	35	42	51	58	66	84	89	98	63	93	127
Cooling Tower Number of Fans		9	9	9	9	9	9	9	9	9	9	9	9
Duct Burner Heat Input	HC, MMBtu/h (LHV)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	378.65	378.65	378.65
	HC, MMBtu/h (HHV)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	420.00	420.00	420.00
Stack Exit	Flow, lb/h	2,447,000	2,808,000	3,397,000	2,102,000	2,605,000	3,155,633	2,145,000	2,369,000	2,961,000	3,415,302	3,173,935	2,979,302
	Flow, acfm	766,319	884,520	1,080,812	658,627	823,180	1,008,225	679,965	752,158	954,429	1,063,297	993,442	939,970
Stack Velocity	ft/s using 18' stack diameter	50	58	71	43	54	66	45	49	63	70	65	62
	Temperature, F	181.3	185.2	191.6	179.9	184.5	191.4	185.1	185.6	193.3	175.2	175.5	177.1
Stack Emissions (Uncontrolled)													
NOx	ppmvd@15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	11.6	11.7	11.9
CO	ppmvd@15% O2	7.2	7.2	7.3	7.6	7.2	7.2	7.7	7.3	7.1	14.7	15.1	15.5
VOC	ppmvd@15% O2	1.2	1.2	1.2	1.3	1.2	1.2	1.3	1.2	1.2	2.5	2.6	2.7
SO2	ppmvd@15% O2	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.375	0.372	0.370
NOx	lb/h as NO2	41.0	47.1	56.5	33.3	43.5	52.6	33.3	38.9	49.2	90.1	86.2	82.8
CO	lb/h	20.0	23.0	27.8	17.1	21.2	25.6	17.4	19.1	23.8	69.8	67.6	65.8
VOC	lb/h as CH4	1.9	2.2	2.7	1.7	2.1	2.5	1.7	1.9	2.4	6.9	6.7	6.6
SO2	lb/h	2.6	3.0	3.6	2.1	2.8	3.4	2.1	2.5	3.2	4.1	3.8	3.6
Stack Emissions													
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
% NOx Reduction Required		77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	82.7%	82.9%	83.1%
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
% CO Reduction Required		72.3%	72.2%	72.5%	73.7%	72.2%	72.2%	74.1%	72.5%	72.0%	86.4%	86.7%	87.1%
VOC	ppmvd@15% O2										1.5	1.5	1.6
% VOC Reduction											41.0%	41.0%	42.0%
SO2 (UNCONTROLLED)	ppmvd@15% O2	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.375	0.372	0.370
NH3 Slip	ppmvd@15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NOx	lb/h as NO2	9.1	10.5	12.6	7.4	9.7	11.7	7.4	8.6	10.9	15.6	14.7	14.0
CO	lb/h	5.5	6.4	7.6	4.5	5.9	7.1	4.5	5.3	6.7	9.5	9.0	8.5
VOC	lb/h as CH4										4.1	4.0	3.8
SO2 (UNCONTROLLED)	lb/h	2.6	3.0	3.6	2.1	2.8	3.4	2.1	2.5	3.2	4.1	3.8	3.6

Emissions Data

Fuel Fired		Natural Gas
DESCRIPTION	UNITS	
System Performance		
Steam Flow (Gross)	Lb/hr	41,500
Steam Pressure	PSIG	150
System Efficiency (HHV)	%	83.7
Stack Gas Temperature	ºF	300
Stack Gas Flow	Lbs/hr	44,110
Stack Gas Flow	ACFM	14,731
Stack Diameter	in	30"
Stack Exit Velocit	Ft/sec	50
Furnace Volume	Ft^3	1013
Total Heat Input (HHV)	MMBtu/Hr	50.0
Fuel Higher Heating Value	Btu/SCF	1033
	Btu/lb	22,925
Emissions		
NOx	Lbs/MMBtu	0.036
	PPM	30
	Lbs/hr	1.80
CO	Lbs/MMBtu	0.037
	PPM	50
	Lbs/hr	1.85
PM/PM-10	Lbs/MMBtu	0.007
	Lbs/hr	0.35
VOC	Lbs/MMBtu	0.004
	Lbs/hr	0.20

Notes:

1. Feedwater temperature to boiler is 228°F.
2. Ambient temperature is 80°F.
3. Emissions guarantees are from 25% to 100% MCR only.

Rentech Boiler Systems, Inc.
Abilene Office: 5025 E. Business 20 • Abilene, TX 79601 • Phone: 325-672-3400 • Fax: 325-672-9996
Lincoln Office: 145 North 46th Street • Lincoln, NE 68503 • Phone: 402-474-4242 • Fax: 402-474-4243

Cummins Fire Power

EPA Tier 3 Emission Data
Fire Pump NSPS Compliant

CFP9E-F10 Fire Pump Driver

Type: 4 Cycle; In-Line; 6 Cylinder
Aspiration: Turbocharged, Charge Air Cooled

15 PPM Diesel Fuel																		
		Fuel Consumption		D2 Cycle Exhaust Emissions										Exhaust			
				Grams per BHP - HR					Grams per kW - HR					Temperature		Gas Flow	
RPM	BHP	Gal/Hr	L/hr	NMHC	NOx	NMHC+NOx	CO	PM	NMHC	NOx	NMHC+NOx	CO	PM	°F	°C	CFM	L/sec
1470	215	11.1	42.0	0.123	2.200	2.323	1.417	0.118	0.165	2.950	3.116	1.900	0.158	971	522	1432	676
1760	260	13.4	50.7											997	536	1751	826
1900	275	11.3	42.8											1008	542	1872	884
2100	246	12.9	48.8											968	520	1922	907
2300	212	11.3	42.8											890	477	1884	889

The emissions values above are based on CARB approved calculations for converting EPA (500 ppm) fuel to CARB (15 ppm) fuel.

300-4000 PPM Diesel Fuel																	
		Fuel Consumption		D2 Cycle Exhaust Emissions										Exhaust			
				Grams per BHP - HR					Grams per kW - HR					Temperature		Gas Flow	
RPM	BHP	Gal/Hr	L/hr	NMHC	NOx	NMHC+NOx	CO	PM	NMHC	NOx	NMHC+NOx	CO	PM	°F	°C	CFM	L/sec
1470	215	11.1	42.0	0.149	2.386	2.535	1.417	0.134	0.2	3.200	3.400	1.900	0.180	971	522	1432	676
1760	260	13.4	50.7											997	536	1751	826
1900	275	11.3	42.8											1008	542	1872	884
2100	246	12.9	48.8											968	520	1922	907
2300	212	11.3	42.8											890	477	1884	889

QSL9 Base Model Manufactured by Cummins Inc.
- Using fuel rating 91518

Reference EPA Standard Engine Family: ACEXL0540AAB
Reference CARB Executive Order: U-R-002-0521

No special options needed to meet current regulation emissions for all 50 states

Test Methods:

EPA/CARB Nonroad emissions recorded per 40CFR89 (ref. ISO8178-1) and weighted at load points prescribed in Subpart E, Appendix A, for Constant Spe Engines (ref. ISO8178-4, D2).

Diesel Fuel Specifications:

Cetane Number: 40-48
Reference: ASTM D975 No. 2-D

Reference Conditions:

Air Inlet Temperature: 25°C (77°F)
Fuel Inlet Temperature: 40°C (104°F)
Barometric Pressure: 100 kPa (29.53 in Hg)
Humidity: 10.7 g/kg (75 grains H_2O/lb) of dry air; required for NOx correction

Restrictions: Intake Restriction set to a maximum allowable limit for clean filter; Exhaust Back Pressure set to maximum allowable limit.

Tests conducted using alternate test methods, instrumentation, fuel or reference conditions can yield different results.

Revision Date: 16JUL2010

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§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

	Case ID	Case A-1	Case A-2	Case A-3	Case A-4	Case A-5	Case A-6	Case A-7	Case A-8	Case A-9	Case A-10	Case A-11
		A10U	A46U	A67U	A102U	A105U	A46F	A67F	A102F	A105F	A102F-CPAG	A105F-CPAG
	Ambient Conditions	10.0F/20%RH	46.0F/45%RH	67.0F/36%RH	102.0F/27%RH	105.0F/25%RH	46.0F/45%RH	67.0F/36%RH	102.0F/27%RH	105.0F/25%RH	102.0F/27%RH	105.0F/25%RH
	HRSG Firing Status	Unfired	Unfired	Unfired	Unfired	Unfired	Fired	Fired	Fired	Fired	Fired	Fired
	STG Output	163.8 MW	165.0 MW	164.7 MW	160.0 MW	159.6 MW	258.2 MW	257.1 MW	251.1 MW	250.7 MW	236.7 MW	236.2 MW
	Inlet Air Cooler Status	Off	Off	On	On	On	Off	On	On	On	On	On
	Number of CTs in service	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG	2x100% CTG
	Number of CTs in service	2	2	2	2	2	2	2	2	2	2	2
	Description											
A	Flow from the supply wells	1,090	1,558	1,956	2,581	2,653	2,212	2,650	3,332	3,405	3,485	3,555
B	Service Water	5	5	5	5	5	5	5	5	5	5	5
C	SW to Potable Water	1	1	1	1	1	1	1	1	1	1	1
D	SW to Plant Drains	4	4	4	4	4	4	4	4	4	4	4
E	SW to OWS	4	4	4	4	4	4	4	4	4	4	4
F	SW to Stormwater Pond	4	4	4	4	4	4	4	4	4	4	4
G	SW to Demin Treatment	20	20	20	20	20	34	34	33	33	34	34
H	Demin Rejects	5	5	5	5	5	8	8	8	8	8	8
I	Fixed Demin Water to Tank	15	15	15	15	15	25	25	25	25	25	25
J	Sample and Misc. Demin Loss	3	3	3	3	3	5	5	4	4	5	5
K	DW to Steam Cycle Makeup + PAG	15	15	15	15	15	25	25	25	25	418	416
L	Steam Cycle Blowdown	15	15	15	15	15	25	25	25	25	25	25
M	Cooling Tower Makeup	1,064	1,533	1,891	2,487	2,554	2,173	2,572	3,224	3,293	2,854	2,922
N	SW to Evap Cooler	0	0	40	69	74	0	40	69	74	69	74
O	Evap Cooler Evaporation	0	0	32	55	59	0	32	55	59	55	59
P	Evap Cooler Blowdown	0	0	8	14	15	0	8	14	15	14	15
Q	Cooling Tower Evaporation	1,012	1,454	1,800	2,368	2,433	2,064	2,448	3,070	3,136	2,844	2,908
R	Water to Softening	1,085	1,553	1,951	2,576	2,648	2,207	2,645	3,327	3,400	3,480	3,550
S	Water with Solids	43	62	78	103	106	88	106	133	136	139	142
T	Softened Water	1,041	1,491	1,873	2,473	2,542	2,118	2,540	3,194	3,264	3,341	3,408
U	Cooling Tower Blowdown	60	86	106	139	143	121	144	181	184	167	171
V	Power Augmentation Water	0	0	0	0	0	0	0	0	0	392	391
W	Water to Portable Demin System	0	0	0	0	0	0	0	0	0	523	521
X	Portable Demin System Rejects	0	0	0	0	0	0	0	0	0	131	130
Y	Portable Demin to Tank	0	0	0	0	0	0	0	0	0	392	391
Z	Demin to Evap Cooler	0	0	0	0	0	0	0	0	0	0	0

Notes:

1)	All Flows are displayed in GPM	
2)	Based on 7FA performance estimates	
3)	Demin treatment recovery rate	75%
4)	Reverse Osmosis 2nd Pass Recovery Rate	90%
5)	Cooling Tower Drift	0.0005%
	Estimated circ water rate per cell	14000
	gpm	0.63
6)	Cooling Tower cycles of concentration	18
7)	Evap Cooler cycles of concentration	5.00
8)	Typical Service Water Use Rate, gpm	5
10)	Blowdown flow from Softener	4.00%
11)	Sample and misc demin losses	18%
12)	Steam cycle blowdown percentage	1%
13)	Percent demin water to evap cooler	0%
14)	Filter backwash flow is assumed to be insignificant	

[ ] - Indicates a plug number

Total Water Consumption and Cooling Tower Blowdown (based off Load Model Rev. C)

Base Load*	
Total Water Consumption	826,319,000 gallons / year or 2,537 acre-ft / year
Cooling Tower Blowdown	43,775,000 gallons / year or 135 acre-ft / year
Cycling Model**	
Total Water Consumption	662,270,000 gallons / year or 2,032 acre-ft / year
Cooling Tower Blowdown	34,890,000 gallons / year or 107 acre-ft / year

* Base Load assumes summer operation of 24 hrs./day with 16 hrs./day duct firing. During spring, fall, and winter the plant will be operated 24 hrs/day M-F with no operation on weekends. A two week outage is assumed to take place in both the spring & fall.

** Cycling operation assumes summer plant operation of 12 hrs./day with duct firing and 12 hrs./day not operating. During spring, fall, and winter the plant will be operated 24 hrs/day M-F with no operation on weekends. A two week outage is assumed to take place in both the spring & fall.

Rev	DESCRIPTION	Dwn	Chk	App	Date
E	Updated water usage, quality	BMC			05-01-08
D	Added Additional HB Cases	BMC			04-21-08
C	Added Demin to Evap Cooler	BMC			04-08-08
B	Deleted HP steam PAG cases	TRA			03-29-08
A	Issued for Review	BMC			03-10-08

BOWIE POWER STATION, LLC
500 MW PHASE 1

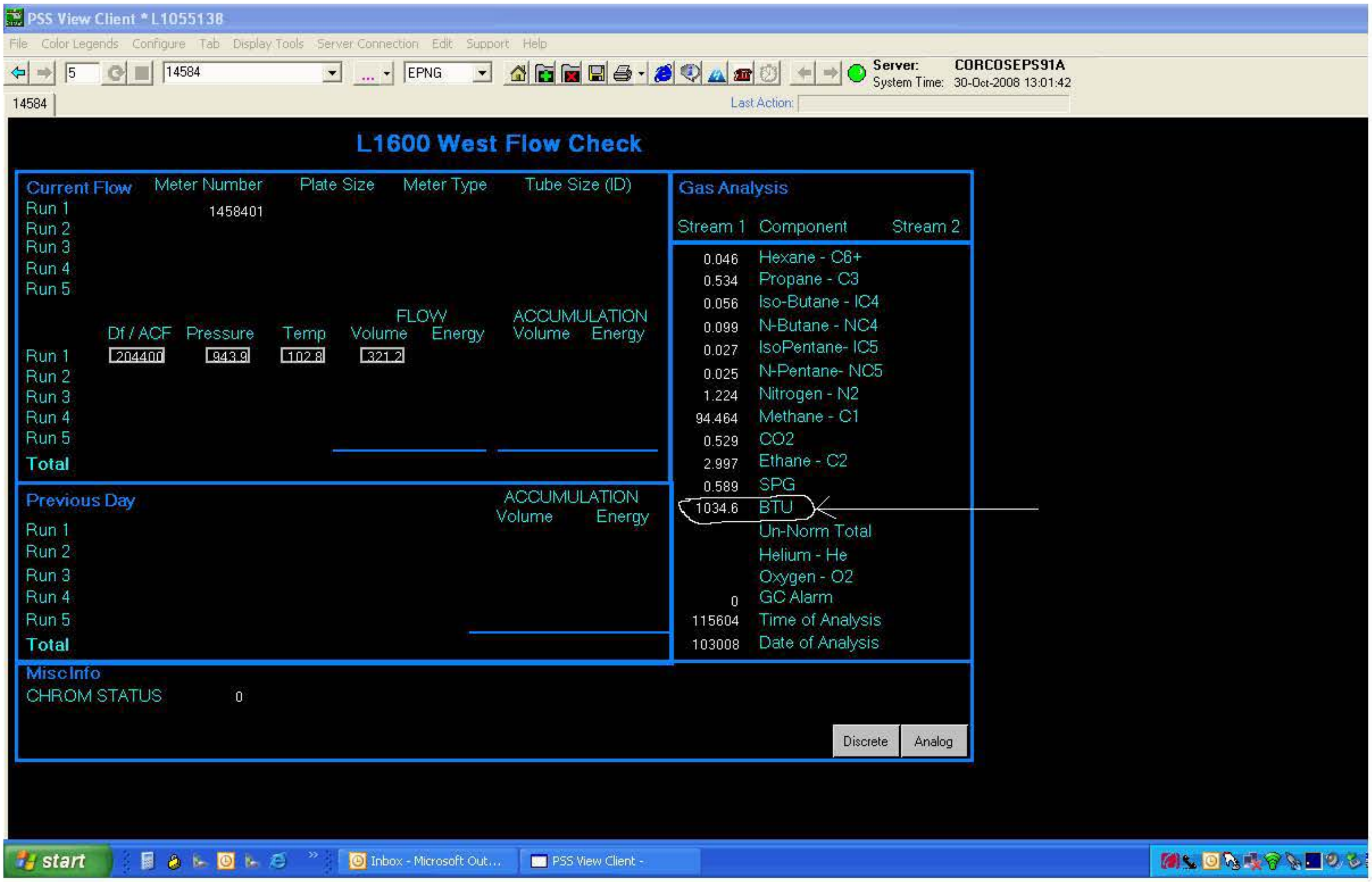
SOUTHWESTERN Power Group LLC

MMR

Kiewit
8455 Lenexa Drive
Lenexa, Kansas 66214

WATER BALANCE FLOW VALUES

	by	date	DRAWING NUMBER
Drawn	BMC	03-10-08	2008-022-WB-002
Checked			
Approved			


PSS View Client * L1055138
File Color Legends Configure Tab Display Tools Server Connection Edit Support Help
Server: CORCOSEPS91A
System Time: 30-Oct-2008 13:01:42
14584
Last Action:
L1600 West Flow Check
Current Flow Meter Number Plate Size Meter Type Tube Size (ID)
Run 1 1458401
Run 2
Run 3
Run 4
Run 5
FLOW ACCUMULATION
Df / ACF Pressure Temp Volume Energy Volume Energy
Run 1 204400 943.9 102.8 321.2
Run 2
Run 3
Run 4
Run 5
Total
Previous Day
ACCUMULATION
Volume Energy
Run 1
Run 2
Run 3
Run 4
Run 5
Total
Misc Info
CHROM STATUS 0
Gas Analysis
Stream 1 Component Stream 2
0.046 Hexane - C6+
0.534 Propane - C3
0.056 Iso-Butane - IC4
0.099 N-Butane - NC4
0.027 IsoPentane- IC5
0.025 N-Pentane- NC5
1.224 Nitrogen - N2
94.464 Methane - C1
0.529 CO2
2.997 Ethane - C2
0.589 SPG
1034.6 BTU
Un-Norm Total
Helium - He
Oxygen - O2
0 GC Alarm
115604 Time of Analysis
103008 Date of Analysis
Discrete
Analog
start
Inbox - Microsoft Out...
PSS View Client -

October 2, 2009

Mr. Andy Siegfried
Senior Project Manager
Rooney Engineering, Inc.
12201 E. Arapahoe Rd
Suite C-10
Centennial, CO 80112

File: Gas Quality Request

Subject: Request for Total Sulfur Content of Natural Gas – South Arizona

Dear Mr. Siegfried:

The average amount of Total Sulfur contained in El Paso's natural gas deliveries made in the Southern Arizona area in 2009 was 0.143 grains per 100 standard cubic feet. The sources of natural gas transported on the El Paso's System do vary on a daily basis. The changes in supplies may reflect a higher or lower level of Total Sulfur depending on the sources.

The following are the monthly averages for 2009.

Month	Grains/100cf	Month	Grains/100cf
January	0.165	July	0.112
February	0.149	August	0.193
March	0.152	September	0.127
April	0.112	October	
May	0.127	November	
June	0.147	December	

The El Paso FERC Tariff allows gas volumes in the El Paso System to contain the following levels of sulfur:

Total Sulfur (TS)	0.75 grains/100 scf
Mercaptan Sulfur (RSH)	0.30 grains/100 scf
Organic Sulfur (OS)	0.50 grains/100 scf
Hydrogen Sulfide (H_2S)	0.25 grains/100 scf

Please contact me at 432-686-3223, if you require additional information or assistance.

Yours truly,

William (Bill) H. Ryan
Principal Specialist Gas Quality
Measurement Services
El Paso Corporation

cc Lori Saylor Rob Runyan Dennis Weatherly Pat Amparan

L20091002 SwP 09 SUL. Doc

TYPICAL PARAMETERS OF VARIOUS FUELS[a]

Type Of Fuel	Heating Value		Sulfur % (by weight)	Ash % (by weight)
	kcal	Btu		
Solid Fuels				
Bituminous Coal	7,200/kg	13,000/lb	0.6-5.4	4-20
Anthracite Coal	6,810/kg	12,300/lb	0.5-1.0	7.0-16.0
Lignite (@ 35% moisture)	3,990/kg	7,200/lb	0.7	6.2
Wood (@ 40% moisture)	2,880/kg	5,200/lb	N	1-3
Bagasse (@ 50% moisture)	2,220/kg	4,000/lb	N	1-2
Bark (@ 50% moisture)	2,492/kg	4,500/lb	N	1-3[b]
Coke, Byproduct	7,380/kg	13,300/lb	0.5-1.0	0.5-5.0
Liquid Fuels				
Residual Oil	$9.98 \times 10^6/m^3$	150,000/gal	0.5-4.0	0.05-0.1
Distillate Oil	$9.30 \times 10^6/m^3$	140,000/gal	0.2-1.0	N
Diesel	$9.12 \times 10^6/m^3$	137,000/gal	0.4	N
Gasoline	$8.62 \times 10^6/m^3$	130,000/gal	0.03-0.04	N
Kerosene	$8.32 \times 10^6/m^3$	135,000/gal	0.02-0.05	N
Liquid Petroleum Gas	$6.25 \times 10^6/m^3$	94,000/gal	N	N
Gaseous Fuels				
Natural Gas	$9,341/m^3$	1,050/SCF	N	N
Coke Oven Gas	$5,249/m^3$	590/SCF	0.5-2.0	N
Blast Furnace Gas	$890/m^3$	100/SCF	N	N

[a] N = negligible.
[b] Ash content may be considerably higher when sand, dirt, etc., are present.

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§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

§ 80.510 What are the standards and marker requirements for NRLM diesel fuel and ECA marine fuel?

(b) *Beginning June 1, 2010* . Except as otherwise specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR diesel fuel.

(ii) 500 ppm maximum for LM diesel fuel.

(2) Cetane index or aromatic content, as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

BOWIE POWER STATION - MODEL 4
ANNUAL PROJECT CRITERIA POLLUTANT EMISSIONS

Equipment

Turbines and Duct Burners	2
Auxiliary Boilers	1
Emergency Fire Pumps	1
Cooling Towers	1
Evaporation Pond	1
Circuit Breakers	5

Annual Criteria Pollutant Emissions - Per Piece of Equipment

	Emissions (tons/year)											
	NO_x	**CO**	**VOC**	**SO_2**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CO_2e**
Per Turbine and Duct Burner Pair	69.47	80.54	14.97	15.00	31.27	31.27	31.27	875,526.11	16.51	1.65	---	876,384.55
Per Auxiliary Boiler	0.41	0.42	0.05	0.02	0.08	0.08	0.08	1,315.23	0.02	0.002	---	1,316.52
Per Emergency Fire Pump	0.06	0.04	0.004	0.00016	0.003	0.003	0.003	14.97	0.0006	0.0001	---	15.02
Per Cooling Tower	---	---	0.64	---	5.67	3.83	1.82	---	---	---	---	---
Evaporation Ponds	---	---	2.15E-04	---	---	---	---	---	---	---	---	---
Circuit Breakers	---	---	---	---	---	---	---	---	---	---	0.0002	4.30

Annual Criteria Pollutant Emissions - Per Equipment Type

	Total Project Emissions (tons/year)											
Emission Source	**NO_x**	**CO**	**VOC**	**SO_2**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CO_2e**
Turbine and Duct Burner Total	138.93	161.08	29.94	30.00	62.54	62.54	62.54	1,751,052.21	33.02	3.30	---	1,752,769.09
Auxiliary Boiler Total	0.41	0.42	0.05	0.02	0.08	0.08	0.08	1315.23	0.02	0.002	---	1,316.52
Fire Pump Total	0.06	0.04	0.004	0.00	0.003	0.003	0.003	14.969	0.001	0.0001	---	15.02
Cooling Tower Total	---	---	0.64	---	5.67	3.83	1.82	---	---	---	---	---
Evaporation Pond Total	---	---	2.15E-04	---	---	---	---	---	---	---	---	---
Circuit Breakers	---	---	---	---	---	---	---	---	---	---	0.0009	21.51
Project Total	**139.40**	**161.54**	**30.64**	**30.03**	**68.29**	**66.45**	**64.45**	**1,752,382.41**	**33.04**	**3.30**	**0.0009**	**1,754,122.14**

TONS PER YEAR FOR EACH PIECE OF EQUIPMENT AT MAXIMUM OPERATION
For turbines and duct burners:
Ton/year values are from the spreadsheet titled "Combined Turbine and Duct Burner Annual Emissions"

For auxiliary boiler:
Ton/year values are from the spreadsheet titled "Auxiliary Boiler Data and Emissions".

For emergency fire pump:
Ton/year values are from the spreadsheet titled "Emergency Fire Pump Data and Emissions".

For cooling tower:
Tons/year value comes from the spreadsheest titled "Cooling Tower PM/PM_{10}/$PM_{2.5}$ Emissions" and "Cooling Tower HAP Emissions"

For evaporation pond:
Tons/year value comes from the spreadsheet titled "Evaporation Pond Chloroform Emissions".

CO_2, CH_4, N_2O, SF_6, and CO_2e:
Tons/year values are from the spreadsheet titled "Annual Greenhouse Gas Emissions"

Total Project Emissions tons = tons Each Piece of Equipment x # of Pieces of Equipment

For turbines, duct burners, auxiliary boiler, and emergency fire pump assume PM_{10} = $PM_{2.5}$

BOWIE POWER STATION - MODEL 4
ANNUAL CRITERIA POLLUTANT EMISSIONS SUMMARY - UNCONTROLLED

Annual Criteria Pollutant Emissions

	Emissions (tons/year)											
	NO_x	CO	VOC	SO_2	PM	PM_{10}	$PM_{2.5}$	CO_2	CH_4	N_2O	SF_6	CO_2e
Per Turbine and Duct Burner Pair	295.8	238.4	22.6	15.0	31.3	31.3	31.3	875,526.11	16.51	1.65	---	876,384.55
Per Auxiliary Boiler	0.41	0.42	0.05	0.02	0.08	0.08	0.08	1,315.23	0.02	0.002	---	1,316.52
Per Emergency Fire Pump	0.06	0.04	0.004	0.00	0.003	0.003	0.003	14.97	0.0006	0.0001	---	15.02
Per Cooling Tower	---	---	0.64	---	5.67	3.83	1.82	---	---	---	---	---
Evaporation Ponds	---	---	2.15E-04	---	---	---	---	---	---	---	---	---
Per Circuit Breaker	---	---	---	---	---	---	---	---	---	---	0.0002	4.30

TONS PER YEAR FOR EACH PIECE OF EQUIPMENT AT MAXIMUM OPERATION

For turbines and duct burners

Ton/year are from the spreadsheet titled "Combined Turbine and Duct Burner Annual Emissions".

For auxiliary boiler:

Ton/year values are from the spreadsheet titled "Aux Boiler Data and Emissions".

For emergency fire pump:

Ton/year values are from the spreadsheet titled "Emergency Fire Pump Data and Emissions".

For cooling tower:

Tons/year value comes from the spreadsheets titled "Cooling Tower PM/PM_{10}/$PM_{2.5}$ Emissions" and Cooling Tower HAP Emissions"

For evaporation ponds:

Tons/year value comes from the spreadsheet titled "Evaporation Pond Chloroform Emissions".

CO_2, CH_4, N_2O, SF_6, and CO_2e:

Tons/year values are from the spreadsheet titled "Annual Greenhouse Gas Emissions"

For turbines, duct burners, auxiliary boiler, and emergency fire pump assume PM_{10} = $PM_{2.5}$

BOWIE POWER STATION - MODEL 4
ONE-HOUR CRITERIA POLLUTANT EMISSION SUMMARY

Maximum One-Hour Emissions

Emission Basis	Emissions (pounds/hour)											
	Normal Operation							Startup Operation				
	NOx	CO	VOC	SO_2	PM	PM_{10}	$PM_{2.5}$	NOx	CO	VOC	SO_2	$PM_{10}/PM_{2.5}$
Per Turbine and Duct Burner Pair	15.60	9.50	4.10	4.10	8.50	8.50	8.50	101.32	262.28	17.56	3.60	6.50
Per Aux. Boiler	1.80	1.85	0.20	0.11	0.35	0.35	0.35					
Per Fire Pump	1.26	0.81	0.07	0.003	0.07	0.07	0.07					
Per Cooling Tower	---	---	0.15	---	1.29	0.87	0.42					
Evaporation Ponds	---	---	4.92E-05	---	---	---	---					

For turbines and Duct Burners:
Normal operation values are from the spreadsheet titled "Combined Turbine and Duct Burner Hourly Emission Rates"
Startup values for NOx, CO, and VOC are maximum values from the spreadsheet titled "Turbine Startup Emissions"
Startup values for SO2 and $PM_{10}/PM_{2.5}$ are maximum turbine only (no duct firing) emissions from the spreadshee "Turbine Hourly CriteriaEmission"

For auxiliary boiler:
Ton/year values are from the spreadsheet titled "Auxiliary Boiler Data and Emissions".

For emergency fire pump:
Ton/year values are from the spreadsheet titled "Emergency Fire Pump Data and Emissions".

For cooling tower:
Tons/year value comes from the spreadsheets titled "Cooling Tower PM/$PM_{10}/PM_{2.5}$ Emissions" and "Cooling Tower HAP Emissions"

For evaporation pond:
Tons/year value comes from the spreadsheet titled "Evaporation Pond Chloroform Emissions".

Total Project Emissions tons = tons Each Piece of Equipment x # of Pieces of Equipment

For turbines, duct burners, auxiliary boiler, and emergency fire pump assume $PM_{10} = PM_{2.5}$

BOWIE POWER STATION - MODEL 4
ANNUAL HAP POLLUTANT EMISSION SUMMARY

Equipment

Turbines and Duct Burners	2
Auxiliary Boilers	1
Fire Pumps	1
Cooling Towers	1
Evaporation Ponds	1

	Emissions (tons/year)					
Pollutant	Each Turbine and Duct Burner	Each Auxiliary Boiler	Each Emergency Fire Pump	Each Cooling Tower	Evaporation Ponds	Project Total
Acetaldehyde	9.91E-02		7.04E-05			0.20
Acrolein	1.59E-02					0.03
Antimony				5.05E-05		0.00005
Arsenic	1.71E-04	2.17E-06		7.57E-05		0.0004
Benzene	3.03E-02	2.28E-05	8.56E-05			0.06
Beryllium				1.26E-05		0.00001
Cadmium	9.43E-04	1.20E-05		5.05E-05		0.002
Chloroform				6.45E-01	2.15E-04	0.65
Chromium	1.20E-03	1.52E-05		1.26E-04		0.003
Cobalt	7.20E-05	9.13E-07				0.0001
Dichlorobenzene	3.09E-04	1.30E-05				0.0006
Ethylbenzene	7.93E-02		2.06E-06			0.16
Formaldehyde	1.78E+00	8.16E-04	1.08E-04			3.56
Hexane	4.63E-01	1.96E-02				0.95
Lead	4.29E-04	5.44E-06		5.05E-05		0.0009
Manganese	3.26E-04	4.13E-06				0.0007
Mercury	2.23E-04	2.83E-06		5.61E-06		0.0005
Naphthalene	3.38E-03	6.63E-06	7.78E-06			0.007
Nickel	1.80E-03	2.28E-05		1.26E-04		0.004
POMs[a]	5.46E-03	5.63E-07	1.54E-05			0.01
Selenium				5.05E-05		0.00005
Toluene	3.23E-01	3.70E-05	3.75E-05			0.65
Xylenes	1.59E-01		2.62E-05			0.32
				TOTAL FEDERAL HAPs		6.59

[a]Note that PAHs are a subset of POMs

BOWIE POWER STATION - MODEL 4
ANNUAL HAP POLLUTANT EMISSION SUMMARY

ANNUAL HAP EMISSIONS IN TONS PER YEAR

Values for Turbine and Duct Burners are the from the spreadsheets titled "Turbine and Duct Burner HAP Emissions" .

Because PAHs are a subset of POMs, the value for POMs for the turbines and duct burners is the value for PAHs emissions.

Values for Auxiliary Boiler are from the spreadsheet titled "Auxiliary Boiler Data and Emissions".

Values for Emergency Fire Pump are from the spreadsheet titled "Emergency Fire Pump Data and Emissions"

Values for the Cooling Tower are from the spreadsheet titled "Cooling Tower HAPs".

Values for the Evaporation Pond are from the spreadsheet titled "Evaporation Pond Chloroform Emissions".

Total of each pollutant for the Project is calculated as follows:

$$\frac{\text{tons}}{\text{year}} = \left(\frac{\text{tons}}{\text{year}} \text{ for each turbine } \times \text{ number of turbines}\right) + \left(\frac{\text{tons}}{\text{year}} \text{ for each auxiliary boiler } \times \text{ number of auxiliary boilers}\right)$$

$$+ \left(\frac{\text{tons}}{\text{year}} \text{ for fire pump } \times \text{ number of fire pumps}\right) + \left(\frac{\text{tons}}{\text{year}} \text{ for each cooling tower } \times \text{ number of cooling towers}\right) + \left(\frac{\text{tons}}{\text{year}} \text{ for evaporation ponds}\right)$$

BOWIE POWER STATION - MODEL 4
EMISSION REFERENCE SUMMARY LIST

TURBINE

Normal Operation:
NO_x, CO, VOCs and SO_2 - provided by Kiewit Power Engineers Co. based on Gatecycle Modeling
$PM/PM_{10}/PM_{2.5}$ - based on sulfur content of fuel, source testing of similar combustion turbines, and the results of the best available control technology analysis
HAPs - AP-42, Section 3.1, Table 3.1-3, April 2000

Startup/Shutdown
NO_x, CO, VOCs - values from Kiewit Power Engineers Co.
SO_2 and $PM/PM_{10}/PM_{2.5}$ - Assume same as normal operations

DUCT BURNERS

Criteria Pollutants except for $PM/PM_{10}/PM_{2.5}$- from Kiewit Power Engineers Co.
$PM/PM_{10}/PM_{2.5}$ - based on sulfur content of fuel, source testing of similar units, and the results of the best available control technology analysis
HAPs - AP-42, Section 1.4, Tables 1.4-2, -3, and -4, July 1998

AUXILIARY BOILER

NO_x, CO, VOC, $PM/PM_{10}/PM_{2.5}$ provided by Rentech
SO_2 - AP-42, Section 1.4, Table 1.4-2, July 1998, adjusted based on natural gas sulfur content from El Paso Natural Gas
HAPs - AP-42, Section 1.4 Tables 1.4-3 and -4, July 1998

EMERGENCY FIRE PUMP

NOx, CO, VOC, $PM/PM_{10}/PM_{2.5}$ - Cummins CFP9E-F10 Fire Power Engine Specification Sheet
SO_2 AP-42, Section 3.4, Table 3.4-1, October 1996
HAPs - AP-42, Section 3.3, Table 3.3-2 and WebFIRE

COOLING TOWERS

PM_{10} - Based on design of drift eliminators, cooling tower circulating rate, and total dissolved solids content of water. Percentage of PM that is PM_{10} based on calculation from 2001 AWMA paper. Droplet Distribution for drift eliminators from Marley
HAPs (except chloroform) - based on cooling tower drift and content of blowdown
Chloroform - from EPA's, *Locating and Estimating Air Emissions from Sources of Chloroform*

EVAPORATION PONDS

Chloroform - from EPA's, *Locating and Estimating Air Emissions from Sources of Chloroform*

GHG Emissions

CO_2 - 40 Code of Federal Regulations 98, Table C-1, "Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel".
CH_4 and N_20 - 40 Code of Federal Regulations 98, Table C-2, "Default CH_4 and N_2O Emission Factors for Various Types of Fuel".
Global Warming Potentials - From 40 CFR 98, Table A-1 "Global Warming Potentials"
Substation Leak Rate from *Electric Power Substation Engineering* , 2nd Edition, 2007, Edited by John D. McDonald. "Field checks of GIS [gas-insulated substations] in service after many years of service indicate that a leak rate objective lower than 0.1% per year is obtainable".

BOWIE POWER STATION
COMBINED TURBINE AND DUCT BURNER ANNUAL EMISSIONS

Duct Burner Hours of Operation for capacity factor assuming 100% load =		4224	hours/year
Hours in Shutdown =		91.25	hours/year
Turbine Capacity Factor =		95%	
Hours of Turbine Operation (no duct firing) per Year =		3681.75	hours/year
Startup Hours =		325.0	hours/year
	TOTAL	8322.0	hours/year

NOx Emissions (uncontrolled)		**tons/year**
Startup Emissions		14.15
Turbine + Duct Firing		182.05
Turbine		96.83
Shutdown		2.73
	Total	**295.77**

NOx Emissions (Controlled)		**tons/year**
Startup Emissions (partial control)		14.15
Turbine + Duct Firing		31.05
Turbine		21.54
Shutdown		2.73
	Total	**69.47**

CO Emissions (uncontrolled)		**tons/year**
Startup Emissions		39.54
Turbine + Duct Firing		142.77
Turbine		47.13
Shutdown		8.92
	Total	**238.36**

CO Emissions (controlled)		**tons/year**
Startup Emissions (partial control)		39.54
Turbine + Duct Firing		19.01
Turbine		13.07
Shutdown		8.92
	Total	**80.54**

BOWIE POWER STATION
COMBINED TURBINE AND DUCT BURNER ANNUAL EMISSIONS

VOC Emissions (uncontrolled)		**tons/year**
Startup Emissions		2.72
Turbine + Duct Firing		14.15
Turbine		4.60
Shutdown		1.08
	Total	**22.56**

VOC Emissions (controlled)		**tons/year**
Startup Emissions (partial control)		2.72
Turbine + Duct Firing		8.45
Turbine		2.72
Shutdown		1.08
	Total	**14.97**

SO_2 Emissions		**tons/year**
Startup Emissions		0.55
Turbine + Duct Firing		8.03
Turbine		6.26
Shutdown		0.16
	Total	**15.00**

$PM/PM_{10}/PM_{2.5}$ Emissions		**tons/year**
Startup Emissions		1.06
Turbine + Duct Firing		17.95
Turbine		11.97
Shutdown		0.30
	Total	**31.27**

Hours of Turbine only Operation:

Turbine Only Operation $\frac{\text{hours}}{\text{year}} = (8760 \frac{\text{hours}}{\text{year}} \times \text{capacity factor}) - \text{duct burner operation} \frac{\text{hours}}{\text{year}} - \text{startup} \frac{\text{hours}}{\text{year}} - \text{shutdown} \frac{\text{hours}}{\text{year}}$

Startup and Normal Operation lb/hour emission values used in calculations for all pollutants are from the spreadsheet "Turbine and Duct Burner Hourly".

Emissions are calculated based on the annual average ambient temperature of 59°F.

Shutdown emission values are from the spreadsheet "Turbine Shutdown Emissions".

$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{hour}} \times \frac{\text{hours}}{\text{year}} \times \frac{\text{tons}}{\text{2000 lb}}$

BOWIE POWER STATION
TURBINE AND DUCT BURNER HOURLY EMISSION RATES

Duct Burners =	420	mmBtu/hour maximum heat input
Duct Burners $PM/PM_{10}/PM_{2.5}$ (front and back half)	2.0	

Based on source testing of similar combustion turbines and the results of the Best Available Control Technology Analysis

NO_x (uncontrolled) **lb/hour**

		Ambient Temperature		
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$
Turbine Startup	Startup	101.32	87.08	92.82
Turbine + Duct Firing	100%	90.1	86.2	82.8
Turbine	100%	56.5	52.6	49.2
Turbine	80%	47.1	43.5	38.9
Turbine	Minimum Compliance Load	41.0	33.3	33.3

NO_x (controlled) **lb/hour**

		Ambient Temperature						
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$				
Turbine Startup Average (No Control)	Startup	101.32	87.08	92.82				
Turbine + Duct Firing	100%	15.6	14.7	14.0	Maximum Normal Operation =	15.60	lb/hour	controlled
Turbine	100%	12.6	11.7	10.9				
Turbine	80%	10.5	9.7	8.6				
Turbine	Minimum Compliance Load	9.1	7.4	7.4				

CO (uncontrolled) **lb/hour**

		Ambient Temperature		
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$
Turbine Startup Average (No Control)	Startup	262.28	243.32	240.28
Turbine + Duct Firing	100%	69.8	67.6	65.8
Turbine	100%	27.8	25.6	23.8
Turbine	80%	23.0	21.2	19.1
Turbine	Minimum Compliance Load	20.0	17.1	17.4

CO (controlled) **lb/hour**

		Ambient Temperature						
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$				
Turbine Startup (No control)	Startup	262.28	243.32	240.28				
Turbine + Duct Firing	100%	9.5	9.0	8.5	Maximum Normal Operation =	9.50	lb/hour	controlled
Turbine	100%	7.6	7.1	6.7				
Turbine	80%	6.4	5.9	5.3				
Turbine	Minimum Compliance Load	5.5	4.5	4.5				

BOWIE POWER STATION
TURBINE AND DUCT BURNER HOURLY EMISSION RATES

VOC (uncontrolled) — **lb/hour**

		Ambient Temperature		
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$
Turbine Startup Average (No Control)	Startup	17.56	16.76	16.06
Turbine + Duct Firing	100%	6.9	6.7	6.6
Turbine	100%	2.7	2.5	2.4
Turbine	80%	2.2	2.1	1.9
Turbine	Minimum Compliance Load	1.9	1.7	1.7

VOC (controlled) — **lb/hour**

		Ambient Temperature			
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$	
Turbine Startup (No control)	Startup	17.56	16.76	16.06	
Turbine + Duct Firing	100%	4.1	4.0	3.8	Maximum Normal Operation = 4.10 lb/hour controlled
Turbine	100%	1.6	1.5	1.4	
Turbine	80%	1.3	1.2	1.1	
Turbine	Minimum Compliance Load	1.1	1.0	1.0	

SO_2 — **lb/hour**

		Ambient Temperature			
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$	
Turbine Startup	Startup	3.60	3.40	3.20	Maximum Normal Operation = 4.10 lb/hour
Turbine + Duct Firing	100%	4.1	3.8	3.6	
Turbine	100%	3.6	3.4	3.2	
Turbine	80%	3.0	2.8	2.5	
Turbine	Minimum Compliance Load	2.6	2.1	2.1	

$PM/PM_{10}/PM_{2.5}$ — **lb/hour**

		Ambient Temperature			
Configuration	**Turbine Load**	10^oF	$59\ ^oF$	$102\ ^oF$	
Turbine Startup	Startup	6.50	6.50	6.50	
Turbine + Duct Firing	100%	8.5	8.5	8.5	Maximum Normal Operation = 8.50 lb/hour
Turbine	100%	6.5	6.5	6.5	
Turbine	80%	6.5	6.5	6.5	
Turbine	Minimum Compliance Load	6.5	6.5	6.5	

Startup emissions are the maximum emissions for each ambient temperature from spreadsheet titled "Turbine Startup Data & Emissions". For SO_2 and $PM/PM_{10}/PM_{2.5}$ maximum normal operation emission rate is used for startup

Turbine normal operation emissions are from heat balance provided by Kiewit Power Engineers. Heat balance shows no control for VOCs with no duct firing. Control efficiency of 41.0% from heat balance for VOC emissions with duct firing used to calculate controlled VOC emissions for normal operation with no duct firing.

Controlled VOC Emissions (no duct firing) $\frac{lb}{hour}$ = Uncontrolled VOC Emissions (no duct firing) $\frac{lb}{hour}$ x (1 - Control Efficiency [0.41])

BOWIE POWER STATION
TURBINE STARTUP EMISSIONS

	Number Per Turbine	Duration (minutes)	Duration (hours)
Hot Starts - <8 hours shutdown	80	30	0.5
Warm Starts - 8 to 72 hours shutdown	220	60	1.0
Cold Starts - >72 hours shutdown	65	60	1.0

Total Hours in Startup/Year	325.0	per turbine

The following uncontrolled emission rates are from spreadsheet: "Bowie_7FA04_Cycle_Emissions_Fill_in_Table Kiewit Revisions 6-19-13", Kiewit Power Engineers CO.

Emission Rates - Hot Starts (lb/event/turbine)

Ambient Temperature

Pollutant	10°F	59 °F	102 °F
NO_x	50.66	43.54	46.41
CO	131.14	121.66	120.14
VOC	8.78	8.38	8.03

Emission Rates - Hot Starts (lb/hour/turbine)

Ambient Temperature

Pollutant	10°F	59 °F	102 °F
NO_x	101.32	87.08	92.82
CO	262.28	243.32	240.28
VOC	17.56	16.76	16.06

Emission Rates - Warm Starts (lb/hour/turbine)[a]

Ambient Temperature

Pollutant	10°F	59 °F	102 °F
NO_x	78.91	69.86	71.03
CO	145.03	134.46	132.03
VOC	10.12	9.63	9.21

Emission Rates - Cold Starts (lb/hour/turbine)[a]

Ambient Temperature

Pollutant	10°F	59 °F	102 °F
NO_x	78.91	69.86	71.03
CO	145.03	134.46	132.03
VOC	10.12	9.63	9.21

[a]As warm and cold starts last 60 minutes, lb/hour emissions and emissions on a lb/event/basis are equivalent.

$$\text{Total } \frac{\text{Hours}}{\text{Year}} \text{ in Startup} = \left(\frac{\text{Number of Hot Start}}{\text{Year}} \times \frac{\text{Hours}}{\text{Hot Start}}\right) + \left(\frac{\text{Number of Warm Starts}}{\text{Year}} \times \frac{\text{Hours}}{\text{Warm Start}}\right) + \left(\frac{\text{Number of Cold Starts}}{\text{Year}} \times \frac{\text{Hours}}{\text{Cold Start}}\right)$$

$$\text{Hot Start } \frac{\text{lb}}{\text{hour}} = \frac{\text{lb}}{\text{event}} \times \frac{\text{event}}{\text{hour}}$$

Ambient Temperature (F)	Revised 6-15-13								
	10			59			102		
	Cold Start	Warm Start	Hot Start	Cold Start	Warm Start	Hot Start	Cold Start	Warm Start	Hot Start
Definition of Start Type	>72 hr	8 to 72 hr	<8 hr	>72 hr	8 to 72 hr	<8 hr	>72 hr	8 to 72 hr	<8 hr
Definition of End of Event	Stack Emissions Compliance			Stack Emissions Compliance			Stack Emissions Compliance		
Duration, minutes	60	60	30	60	60	30	60	60	30
Total NO_x Emissions, lb/event	78.91	78.91	50.66	69.86	69.86	43.54	71.03	71.03	46.41
Total CO Emissions, lb/event	145.03	145.03	131.14	134.46	134.46	121.66	132.03	132.03	120.14
Total VOCs Emissions, lb/event	10.12	10.12	8.78	9.63	9.63	8.38	9.21	9.21	8.03

BOWIE POWER STATION
TURBINE SHUTDOWN EMISSIONS

Shutdowns per year	365	shutdowns/year
Shutdown Duration	0.25	hours/shutdown
Hours in Shutdown	91.25	hours shutdown/year

Conservatively assume that emissions are not controlled during shutdown

Pollutant	Shutdown Uncontrolled Emissions Per Turbine (lbs/shutdown)[a]		
Ambient Temperature	10°F	59 °F	102 °F
NO_x	16.44	14.97	15.70
CO	51.47	48.90	48.53
VOC	6.43	5.94	5.68

[a]Emissions from spreadsheet: Provided by Kiewit Power Engineers CO.

[b]Normal operation emissions includes duct burner emissions.

Annual Shutdown Emissions

	Uncontrolled (tons/year)
NO_x	2.73
CO	8.92
VOC	1.08

For modeling purposes determine maximum emissions in an hour

Calculate Emissions for an hour during which a shutdown event occurs. Maximum

	Normal Operation Controlled Emissions Each Turbine (lb/hour)[b]			Total Controlled Emissions with Normal Operations Followed by Turbine Shutdown (lbs in one hour)			Maximum Emissions for Hour with Shutdown (lb/hour)
	10°F	59 °F	102 °F	10°F	59 °F	102 °F	
NO_x	15.6	14.7	14.0	28.1	26.0	26.2	28.1
CO	9.5	9.0	8.5	58.6	55.7	54.9	58.6
VOC	4.1	4.0	3.8	9.5	8.9	8.5	9.5

Maximum Emissions for Hour with a Startup (lb/hour)	Maximum Normal Operations Emissions (lb/hour)	Condition for Hour with Maximum Emissions
101.32	15.60	Startup
262.28	9.50	Startup
17.56	9.50	Startup

hours in shutdown $\frac{\text{hours}}{\text{year}} = \frac{\text{shutdowns}}{\text{year}} \times \frac{\text{hours}}{\text{shutdown}}$

Conservatively assume that emissions during shutdown are not controlled.

Annual Shutdown Emissions $\frac{\text{tons}}{\text{year}}$ = Emissions for Shutdown Hour @ 59°F $\frac{\text{lb}}{\text{shutdown}} \times \frac{\text{shutdown s}}{\text{year}} \times \frac{\text{tons}}{\text{2000 lbs}}$

Emissions from an hour with normal operations followed by a shutdown event = ($\frac{\text{lb}}{\text{hour}}$ controlled normal operation x portion of hour normal operation) + lbs uncontrolled from shutdown

= ($\frac{\text{lb}}{\text{hour}}$ controlled normal operation x (1 - portion of hour in shutdown)) + lbs uncontrolled from shutdown

Maximum hourly emissions for startup are from "Turbine Startup Emissions" spreadsheet
Maximum hourly emissions for normal operation are from "Turbine and Duct Burner Hourly" spreadsheet

10F Ambient				59F Ambient				102F Ambient			
	Mass Emissions				Mass Emissions				Mass Emissions		
Load (%)	NOx (lb/min)	CO (lb/min)	VOC (lb/min)	Load (%)	NOx (lb/min)	CO (lb/min)	VOC (lb/min)	Load (%)	NOx (lb/min)	CO (lb/min)	VOC (lb/min)
Shutdown	42.53	114.41	6.43	Shutdown	35.90	105.20	5.94	Shutdown	39.20	103.91	5.68

BOWIE POWER STATION
TURBINE AND DUCT BURNER HEAT INPUTS

Heat Input, mmBtu/hour HHV - Total Two Turbines

Ambient Temperature	**10 °F**	**59 °F**	**102 °F**
Turbine + Duct Firing	3469.12	3231.74	3023.86
Turbine 100%	3469.12	3231.74	3023.86
Turbine 80%	2895.28	2670.88	2386.46
Turbine Minimum Compliance Load	2516.42	2041.60	2041.62

Heat Input, mmBtu/hour HHV - Each Turbine

Ambient Temperature	**10 °F**	**59 °F**	**102 °F**
Turbine + Duct Firing	1734.56	1615.87	1511.93
Turbine 100%	1734.56	1615.87	1511.93
Turbine 80%	1447.64	1335.44	1193.23
Turbine Minimum Compliance Load	1258.21	1020.80	1020.81

Turbine Maximum Heat Input Rate

mmBtu per hour (HHV)	**gigaJoules per hour (HHV)**
1734.56	1829.61

Maximum Turbine Annual Heat Input

Capacity Factor	95%
Annual Turbine Heat Input (mmBtu/year)	14,435,008
Annual Turbine Heat Input Both Turbines (mmBtu/year)	28,870,017

Duct Burner Maximum Fuel Use

Duct Burner Heat Input Rate (mmBtu/hour) (HHV)	420
Duct Burner Hours of Operation at Full Load (hours/year)	4224
Annual Duct Burner Heat Input (mmBtu/year)	1,774,080
Annual Duct Burner Heat Input Both Duct Burners (mmBtu/year)	3,548,160

$$\frac{\text{gigaJoules}}{\text{hour}} = \frac{\text{mmBtu}}{\text{hour}} \times \frac{10^6\ \text{Btu}}{\text{mmBtu}} \times \frac{1054.8\ \text{Joule}}{\text{Btu}} \times \frac{\text{gigaJoule}}{10^9\ \text{Joule}}$$

$$\text{Turbine Annual Heat Input } \frac{\text{mmBtu}}{\text{year}} = \text{Maximum Heat Input } \frac{\text{mmBtu}}{\text{hour}} \text{ (HHV)} \times 8760 \frac{\text{hours}}{\text{year}} \times \text{Capacity Factor}$$

$$\text{Duct Burner Annual Heat Input } \frac{\text{mmBtu}}{\text{year}} = \text{Heat Input } \frac{\text{mmBtu}}{\text{hour}} \times \frac{\text{hours}}{\text{year}}$$

BOWIE POWER STATOIN
TURBINE AND DUCT BURNER HAP EMISSIONS

Turbine and duct burner lb/hour emission values are needed to complete the application forms.

Oxidation catalysts provide control for only a portion of each startup sequence. It has been assumed that shutdown emissions are uncontrolled. As a conservative assumption, turbine uncontrolled emissions will be reviewed.

The duct burners do not operate during startup.
During Normal Operation, HAPs will be emitted from both the turbine and duct burner and will be controlled by the oxidation catalyst
For organic HAP hourly emissions, determine whether turbine emissions during startup/shutdown or turbine and duct burner emissions during normal operations are greater.

All values shown below are for one turbine and duct burner pair.

Oxidation Catalyst Control Efficiency	70%

Pollutant	Turbine Uncontrolled Emissions During Startup (lb/hour)	Duct Burner Uncontrolled Emissions (lb/hour)	Turbine + Duct Burner Controlled Emissions during normal operations (lb/hour)	Turbine + Duct Burner Maximum Short-Term Emissions (lb/hour)
Acetaldehyde	7.04E-02		2.11E-02	7.04E-02
Acrolein	1.13E-02		3.38E-03	1.13E-02
Benzene	2.11E-02	8.53E-04	6.59E-03	2.11E-02
Dichlorobenzene		4.87E-04	1.46E-04	1.46E-04
Ethylbenzene	5.63E-02		1.69E-02	5.63E-02
Formaldehyde	1.25E+00	3.04E-02	3.84E-01	1.25E+00
Hexane		7.31E-01	2.19E-01	2.19E-01
Naphthalene	2.29E-03	2.48E-04	7.60E-04	2.29E-03
POMs[a]	3.87E-03	2.10E-05	1.17E-03	3.87E-03
Toluene	2.29E-01	1.38E-03	6.90E-02	2.29E-01
Xylenes	1.13E-01		3.38E-02	1.13E-01

[a]PAHs are a subset of POMs.

Summarize Turbine and Duct Burner HAP Emission:

Pollutant	Turbine + Duct Burner Emissions (lb/hour)[b]	Turbine Emissions (tons/year)	Duct Burner Emissions (tons/year)	Turbine + Duct Burner Emissions (tons/year)
Acetaldehyde	7.04E-02	9.91E-02		9.91E-02
Acrolein	1.13E-02	1.59E-02		1.59E-02
Arsenic	8.12E-05		1.71E-04	1.71E-04
Benzene	2.11E-02	2.97E-02	5.40E-04	3.03E-02
Cadmium	4.47E-04		9.43E-04	9.43E-04
Chromium	5.68E-04		1.20E-03	1.20E-03
Cobalt	3.41E-05		7.20E-05	7.20E-05
Dichlorobenzene	1.46E-04		3.09E-04	3.09E-04
Ethylbenzene	5.63E-02	7.93E-02		7.93E-02
Formaldehyde	1.25E+00	1.76E+00	1.93E-02	1.78E+00
Hexane	2.19E-01		4.63E-01	4.63E-01
Lead	2.03E-04		4.29E-04	4.29E-04
Manganese	1.54E-04		3.26E-04	3.26E-04
Mercury	1.06E-04		2.23E-04	2.23E-04
Naphthalene	2.29E-03	3.22E-03	1.57E-04	3.38E-03
Nickel	8.53E-04		1.80E-03	1.80E-03
POMs[a]	3.87E-03	5.45E-03	1.33E-05	5.46E-03
Toluene	2.29E-01	3.22E-01	8.75E-04	3.23E-01
Xylenes	1.13E-01	1.59E-01		1.59E-01

[a]PAHs are a subset of POMs.

[b]Organic HAP Emissions are maximums from table above. Metal HAPs (arsenic, cadmium, chromium, cobalt, lead, manganese, mercury, and nickel) are from "Duct Burner HAP Emissions".

Turbine Emissions are from "Turbine HAP Emissions" spreadsheet. Duct Burner emissions are from "Duct Burner HAP Emissions"

$$\text{Controlled Emissions } \frac{lb}{hour} = \left(\text{Turbine Emissions } \frac{lb}{hour} + \text{Duct Burner Emissions } \frac{lb}{hour}\right) \times (1 - \text{Control Efficiency})$$

BOWIE POWER STATION
TURBINE HAP EMISSIONS

	per turbine		two turbines	
Turbine Heat Input (HHV) =	1,735	mmBtu/hour	3,469	mmBtu/hour
Annual Heat Input (HHV)=	14,435,008	mmBtu/year	28,870,017	mmBtu/year

Natural Gas Heat Content	1035

Oxidation Catalyst Control Efficiency =	70%	
Oxidation Catalyst Control Efficiency During Startup =	0%	Conservatively assume no HAP control during startup or shutdown

Total Hours per Year in Operation =	8322.0
Hours per Year in Startup =	325.0
Hours per Year in Shutdown =	91.3
Operating Hours per Year in Startup or Shutdown =	416.3
Operating Hours per Year Not in Startup =	7997.0

Hazardous Air Pollutant	**AP-42 Table 3.1-3 Emission Factor (lb/mmBtu)[a]**	**Emission Factor Adjusted for Natural Gas Heat Content (lb/mmBtu)**	**Uncontrolled Hourly Emissions for One Turbine (lb/hr)**	**Controlled Annual Emissions for One Turbine (tons per year)**
Acetaldehyde	4.0E-05	4.06E-05	7.04E-02	9.91E-02
Acrolein	6.4E-06	6.49E-06	1.13E-02	1.59E-02
Benzene	1.2E-05	1.22E-05	2.11E-02	2.97E-02
Ethylbenzene	3.2E-05	3.25E-05	5.63E-02	7.93E-02
Formaldehyde	7.1E-04	7.20E-04	1.25E+00	1.76E+00
Naphthalene	1.3E-06	1.32E-06	2.29E-03	3.22E-03
PAHs	2.2E-06	2.23E-06	3.87E-03	5.45E-03
Toluene	1.3E-04	1.32E-04	2.29E-01	3.22E-01
Xylenes (mixed)	6.4E-05	6.49E-05	1.13E-01	1.59E-01

[a]Emission factors are from AP-42, Section 3.1, Table 3.1-3, April 2000. Pollutants for which AP-42 records one half the source testing detection limit have not been included.

BOWIE POWER STATION
TURBINE HAP EMISSIONS

Conservatively assume maximum heat input during all operating hours:

$$\frac{mmBtu}{year} = \frac{mmBtu}{hour} \times 8760 \frac{hours}{year} \times \text{capacity factor}$$

AP-42 Emission Factor Adjustment for Natural Gas Heat Content from footnote c, Table 3.1-3:

$$\text{Adjusted Emission Factor } \frac{lb}{mmBtu} = \text{AP-42 Emission Factor } \frac{lb}{mmBtu} \times \frac{\text{Heat Content Bowie Natural Gas (Btu/scf)}}{1020 \text{ Btu/scf}}$$

lb/hour uncontrolled

$$\frac{lb}{hour} = \frac{lb}{mmBtu} \times \frac{mmBtu}{hour}$$

tons/year controlled

$$\frac{tons}{year} = \left(\left(\frac{lb}{hour} \times \frac{hours}{year} \text{ of Operation Not in Startup} \times (1 - \text{Control Efficiency})\right) + \left(\frac{lb}{hour} \times \frac{hours}{year} \text{ in Startup}\right)\right) \times \frac{tons}{2000 \text{ lb}}$$

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.
[b] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".
[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.
[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.
[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

BOWIE POWER STATION
DUCT BURNER HAP EMISSIONS

Natural Gas Heat Content	1035	Btu/scf	
Duct Burner Heat Input (HHV) =	420.00	MMBtu/hour	
	1,774,080.00	MMBtu/year	each duct burner
	3,548,160.00	MMBtu/year	combined for two duct burners
Oxidation Catalyst Control Efficiency =	70%		

Hazardous Air Pollutant	Emission Factor lb/million scf	Emission Factor (lb/MMBtu)[1]	Uncontrolled Hourly Emissions for One Duct Burner (lb/hour)	Controlled Annual Emissions for One Duct Burner (tons/year)[2]
Arsenic	2.0E-04	1.9E-07	8.1E-05	1.71E-04
Benzene	2.1E-03	2.0E-06	8.5E-04	5.40E-04
Cadmium	1.1E-03	1.1E-06	4.5E-04	9.43E-04
Chromium	1.4E-03	1.4E-06	5.7E-04	1.20E-03
Cobalt	8.4E-05	8.1E-08	3.4E-05	7.20E-05
Dichlorobenzene	1.2E-03	1.2E-06	4.9E-04	3.09E-04
Formaldehyde	7.5E-02	7.2E-05	3.0E-02	1.93E-02
Hexane	1.8E+00	1.7E-03	7.3E-01	4.63E-01
Lead	0.0005	4.8E-07	2.0E-04	4.29E-04
Manganese	3.8E-04	3.7E-07	1.5E-04	3.26E-04
Mercury	2.6E-04	2.5E-07	1.1E-04	2.23E-04
Naphthalene	6.1E-04	5.9E-07	2.5E-04	1.57E-04
Nickel	2.1E-03	2.0E-06	8.5E-04	1.80E-03
POM	5.2E-05	5.0E-08	2.1E-05	1.33E-05
Toluene	3.4E-03	3.3E-06	1.4E-03	8.75E-04

POM	lb/million scf
2-Methylnaphthalene	2.4E-05
Fluoranthene	3.0E-06
Fluorene	2.8E-06
Phenanathrene	1.7E-05
Pyrene	5.0E-06
Total POM	5.2E-05

[1]Emission factors are from AP-42 Section 1.4 "Natural Gas Combustion", Tables 1.4-2 (lead),-3 (organics), and -4 (metals), July 1998

[2]Organic pollutant emissions are controlled by the oxidation catalysts. Lead and metal pollutant emissions (arsenic, cadmium, chromium, cobalt, lead, manganese, mercury, and nickel) are uncontrolled.

BOWIE POWER STATION
DUCT BURNER HAP EMISSIONS

$$\frac{\text{mmBtu}}{\text{year}} = \frac{\text{mmBtu}}{\text{hour}} \times \frac{\text{hours}}{\text{year}}$$

$$\frac{\text{lb}}{\text{mmBtu}} = \frac{\text{lb}}{\text{million scf}} \times \frac{\text{scf}}{\text{Btu}}$$

Uncontrolled Hourly Emissions

$$\frac{\text{lb}}{\text{hour}} = \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{hour}}$$

Metal HAPs - uncontrolled

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{year}} \times \frac{\text{tons}}{\text{2000 lb}}$$

Organic HAPs - controlled

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{year}} \times \frac{\text{tons}}{\text{2000 lb}} \times (1 - \text{control efficiency})$$

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)$ (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

BOWIE POWER STATION
AUXILIARY BOILER DATA AND EMISSIONS

Stack Parameters

Stack Height	13.7	meters	
	44.9	feet	
Stack Temperature	300	°F	From Rentech Data sheet
	422.04	K	
Stack Exit Velocity	50.00	feet/second	From Rentech Data sheet
	15.24	meters/second	
Stack Diameter	30	inches	From Rentech Data sheet
	2.5	feet	
	0.76	meters	

Operating Data

Heat Input Rating	50	MMBtu/hr
Operating Hours	450	hrs/yr
Natural Gas Heat Content	1,035	Btu/scf
Natural Gas Sulfur Content	0.75	grains/100 scf
	7,500	grains/10^6 scf
Fuel Consumption Rate	0.048	mmscf/hr
Annual Fuel Usage	21.75	mmscf/yr

Criteria Pollutant Emission Estimation

Pollutant	Emission Factor (lb/mmscf)	Adjusted Emission Factor (lb/mmscf)	Emission Factor (lb/mmBtu)	Reference	Hourly Emissions (lb/hour)	Annual Emissions (tpy)
NO_x			0.036	Rentech Data Sheet	1.80	0.41
CO			0.037	Rentech Data Sheet	1.85	0.42
VOC			0.004	Rentech Data Sheet	0.20	0.05
SO_x	0.6	2.25		AP-42, Table 1.4-2, 7/98	0.11	0.02
PM			0.007	Rentech Data Sheet	0.35	0.08
PM_{10}			0.007	Rentech Data Sheet	0.35	0.08

BOWIE POWER STATION
AUXILIARY BOILER DATA AND EMISSIONS

Hazardous Air Pollutant Emission Estimation

Pollutant	Emission Factor (lb/mmscf)	Emission Factor Reference	Hourly Emissions (lb/hour)	Annual Emissions (tpy)
Arsenic	2.0E-04	AP-42, Table 1.4-4, 7/98	9.67E-06	2.17E-06
Benzene	2.1E-03	AP-42, Table 1.4-3, 7/98	1.01E-04	2.28E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4, 7/98	5.32E-05	1.20E-05
Chromium	1.4E-03	AP-42, Table 1.4-4, 7/98	6.77E-05	1.52E-05
Cobalt	8.4E-05	AP-42, Table 1.4-4, 7/98	4.06E-06	9.13E-07
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3, 7/98	5.80E-05	1.30E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3, 7/98	3.62E-03	8.16E-04
Hexane	1.8E+00	AP-42, Table 1.4-3, 7/98	8.70E-02	1.96E-02
Lead	0.0005	AP-42, Table 1.4-2, 7/98	2.42E-05	5.44E-06
Manganese	3.8E-04	AP-42, Table 1.4-4, 7/98	1.84E-05	4.13E-06
Mercury	2.6E-04	AP-42, Table 1.4-4, 7/98	1.26E-05	2.83E-06
Naphthalene	6.1E-04	AP-42, Table 1.4-3, 7/98	2.95E-05	6.63E-06
Nickel	2.1E-03	AP-42, Table 1.4-4, 7/98	1.01E-04	2.28E-05
POM	5.2E-05		2.50E-06	5.63E-07
Toluene	3.4E-03	AP-42, Table 1.4-3, 7/98	1.64E-04	3.70E-05

POM		
2-Methylnaphthalene	2.4E-05	AP-42, Table 1.4-3, 7/98
Fluoranthene	3.0E-06	AP-42, Table 1.4-3, 7/98
Fluorene	2.8E-06	AP-42, Table 1.4-3, 7/98
Phenanathrene	1.7E-05	AP-42, Table 1.4-3, 7/98
Pyrene	5.0E-06	AP-42, Table 1.4-3, 7/98
Total POM	**5.2E-05**	

BOWIE POWER STATION
AUXILIARY BOILER DATA AND EMISSIONS

$$\text{feet} = \text{meters} \times 3.281\ \frac{\text{feet}}{\text{meters}}$$

$$K = \left[\frac{5}{9}(^{\circ}F-32)\right] + 273.15$$

$$\frac{\text{meters}}{\text{second}} = \frac{\text{feet}}{\text{second}} \times \frac{\text{meters}}{3.281\ \text{feet}}$$

$$\text{feet} = \text{inches} \times \frac{\text{feet}}{12\ \text{inches}}$$

$$\text{meters} = \text{inches} \times \frac{\text{feet}}{12\ \text{inches}} \times \frac{\text{meters}}{3.281\ \text{feet}}$$

$$\frac{\text{grains}}{10^6\ \text{scf}} = \frac{\text{grains}}{100\ \text{scf}} \times \frac{1{,}000{,}000\ \text{scf}}{10^6\ \text{scf}}$$

$$\frac{\text{mmscf}}{\text{hour}} = \frac{\text{mmBtu}}{\text{hour}} \times \frac{1{,}000{,}000\ \text{Btu}}{\text{mmBtu}} \times \frac{\text{scf}}{\text{Btu}} \times \frac{\text{mmscf}}{1{,}000{,}000\ \text{scf}}$$

$$\frac{\text{mmscf}}{\text{year}} = \frac{\text{mmscf}}{\text{hour}} \times \frac{\text{hours}}{\text{year}}$$

Adjust AP-42, SO_2 emission factor for heat and sulfur content of Bowie natural gas:

$$\text{Adjusted Emission Factor}\ \frac{\text{lb}}{\text{mmscf}} = \frac{\text{lb}}{\text{mmscf}} \times \frac{\text{Bowie Sulfur Content grains/scf}}{\text{AP-42 Sulfur Content 2,000 grains/scf}}$$

lb/hour emissions:

$$\frac{\text{lb}}{\text{hour}} = \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{hour}}$$

$$\frac{\text{lb}}{\text{hour}} = \frac{\text{lb}}{\text{mmscf}} \times \frac{\text{mmscf}}{\text{hour}}$$

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{hour}} \times \frac{\text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{mmscf}} \times \frac{\text{mmscf}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

BOWIE POWER STATION
EMERGENCY FIRE PUMP DATA AND EMISSIONS

Cummins CFP9E-F10 Fire Power engine

Stack Parameters

Stack Height	35	feet	
	10.7	meters	
Stack Temperature	997	°F	From Cummins sheet
	809.26	K	
Stack Exit Flowrate	1751	cubic ft/minute	From Cummins sheet
Stack Exit Velocity	12,841.59	feet/minute	
	214.03	feet/second	
	65.23	meters/second	
Stack Diameter	5	inches	
	0.42	feet	
	0.13	meters	

Operating Data

Engine Rating	260	hp	
Operating Hours	100	hrs/yr	Hours limit from 40 CFR 60.4211(e)
Fuel Consumption Rate	13.4	gal/hr	Manufacturer's Data
Diesel Heat Content	137,000	Btu/gal	Diesel BTU content from AP-42, Appendix A, Page A-5
Hourly Heat Input	1.84	mmBtu/hour	
Annual Fuel Usage	1.34	thousand gal/year	
Diesel Sulfur Content	15	ppm	Diesel sulfur content required by 40 CFR Subpart IIII 60.4207(b) which refers to 80.510(b)
	0.0015	%	

Criteria Pollutant Emission Estimation - one fire pump

Pollutant	Emission Factor (lb/hp hr)	Emission Factor (lb/hp hr)	Emission Factor (g/hp hr)	Emission Factor Reference	Hourly Emissions (lb/hour)	Annual Emissions (tpy)
NO_x			2.200	Manufacturer	1.26	0.063
CO			1.417	Manufacturer	0.81	0.041
VOC			0.123	Manufacturer	0.07	0.0035
SO_x	8.09E-03 * sulfur content %	1.21E-05		AP-42, 10/96, Table 3.4-1[a]	0.0032	0.00016
PM			0.118	Manufacturer	0.07	0.0034
PM_{10}			0.118	Assume PM_{10} = PM	0.07	0.0034

[a]AP-42 Section 3.3, "Gasoline and Diesel Industrial Engines" indicates that SO_2 emissions are directly related to fuel sulfur content. However, the emission factors provided in that section do not include a factor for fuel sulfur content nor is the fuel sulfur content related to the factors provided. AP-42 Section 3.4, "Large Stationary Diesel and All Stationary Dual-fuel Engines" includes SO_2 emissions factors that take fuel sulfur content into account and that assume that all sulfur in fuel is converted to SO_2. To ensure that the fuel sulfur content is taken into consideration, the emission factor from section 3.4-1 has been used.

BOWIE POWER STATION
EMERGENCY FIRE PUMP DATA AND EMISSIONS

HAP Emission Estimation

HAP	Emission Factor (lb/mmBtu)	Emission Factor (lb/thousand Gallons)	Emission Factor Reference	Hourly Emissions (lb/hour)	Annual Emissions (tpy)
Acetaldehyde	7.67E-04		AP-42, 10/96, Table 3.3-2	1.41E-03	7.04E-05
Benzene	9.33E-04		AP-42, 10/96, Table 3.3-2	1.71E-03	8.56E-05
Ethylbenzene		3.070E-03	WebFIRE SCC 20100102	4.11E-05	2.06E-06
Formaldehyde	1.18E-03		AP-42, 10/96, Table 3.3-2	2.17E-03	1.08E-04
Naphthalene	8.48E-05		AP-42, 10/96, Table 3.3-2	1.56E-04	7.78E-06
PAHs (total)	1.68E-04		AP-42, 10/96, Table 3.3-2	3.08E-04	1.54E-05
Toluene	4.09E-04		AP-42, 10/96, Table 3.3-2	7.51E-04	3.75E-05
Xylene	2.85E-04		AP-42, 10/96, Table 3.3-2	5.23E-04	2.62E-05

$$\text{meters} = \text{feet} \times \frac{\text{meters}}{3.281\text{ feet}}$$

$$K = \left[\frac{5}{9}(^{\circ}F-32)\right] + 273.15$$

$$\text{Exit Velocity } \frac{\text{ft}}{\text{min}} = \frac{\text{Flowrate (ft}^3\text{/min)}}{\text{Area (ft}^2)} = \frac{\text{Flowrate (ft}^3\text{/min)}}{\pi \times \left(\frac{\text{diameter [ft]}}{2}\right)^2} = \frac{\text{Flowrate (ft}^3\text{/min)}}{\pi \times \left(\frac{\text{diameter [inches]} \times \text{ft/12 inches}}{2}\right)^2}$$

$$\frac{\text{ft}}{\text{sec}} = \frac{\text{ft}}{\text{min}} \times \frac{\text{min}}{60\text{ sec}}$$

$$\frac{\text{meters}}{\text{second}} = \frac{\text{ft}}{\text{min}} \times \frac{\text{minute}}{60\text{ seconds}} \times \frac{\text{meters}}{3.281\text{ feet}}$$

$$\text{feet} = \text{inches} \times \frac{\text{feet}}{12\text{ inches}}$$

$$\text{meters} = \text{inches} \times \frac{\text{feet}}{12\text{ inches}} \times \frac{\text{meters}}{3.281\text{ feet}}$$

Heat Input Rate is calculated as follows:

$$\frac{\text{mmBtu}}{\text{hour}} = \frac{\text{gallons}}{\text{hour}} \times \frac{\text{Btu}}{\text{gallon}} \times \frac{\text{mmBtu}}{1{,}000{,}000\text{ Btu}}$$

Annual Fuel Usage is calculated as follows:

$$\frac{\text{thousand gallons}}{\text{year}} = \frac{\text{gallons}}{\text{hour}} \times \text{operational } \frac{\text{hours}}{\text{year}} \times \frac{\text{thousand gallons}}{1{,}000\text{ gallons}}$$

BOWIE POWER STATION
EMERGENCY FIRE PUMP DATA AND EMISSIONS

% Sulfur in Diesel Fuel is Calculated as follows:

$$\% = \frac{\text{parts}}{1{,}000{,}000} \times 100$$

Short-Term Emissions in lb per hour are calculated as follows:

$$\frac{\text{lb}}{\text{hour}} = \frac{\text{grams}}{\text{hp hr}} \times \text{hp} \times \frac{\text{lb}}{453.59\ \text{grams}}$$

$$\frac{\text{lb}}{\text{hour}} = \frac{\text{lb}}{\text{hp hr}} \times \text{hp}$$

$$\frac{\text{lb}}{\text{hour}} = \text{emission factor}\ \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{hour}}$$

$$\frac{\text{lb}}{\text{hour}} = \text{emission factor}\ \frac{\text{lb}}{\text{thousand gallons}} \times \frac{\text{gallons}}{\text{hour}} \times \frac{\text{thousand gallons}}{1{,}000\ \text{gallons}}$$

Annual Emissions in tons per year are calculated as follows:

$$\frac{\text{tons}}{\text{year}} = \frac{\text{grams}}{\text{hp hr}} \times \text{hp} \times \frac{\text{lb}}{453.59\ \text{grams}} \times \frac{\text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lbs}}{\text{hp hr}} \times \text{hp} \times \frac{\text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

$$\frac{\text{tons}}{\text{year}} = \text{emission factor}\ \frac{\text{lb}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{\text{hour}} \times \frac{\text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

$$\frac{\text{tons}}{\text{year}} = \text{emission factor}\ \frac{\text{lb}}{\text{thousand gallons}} \times \frac{\text{thousand gallons}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

Table 3.4-1. GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL-FUEL ENGINES[a]

Pollutant	Diesel Fuel (SCC 2-02-004-01)			Dual Fuel[b] (SCC 2-02-004-02)		
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
NO_x						
Uncontrolled	0.024	3.2	B	0.018	2.7	D
Controlled	0.013[c]	1.9[c]	B	ND	ND	NA
CO	5.5 E-03	0.85	C	7.5 E-03	1.16	D
SO_x[d]	8.09 E-03S_1	1.01S_1	B	4.06 E-04S_1 + 9.57 E-03S_2	0.05S_1 + 0.895S_2	B
CO_2[e]	1.16	165	B	0.772	110	B
PM	0.0007[c]	0.1[c]	B	ND	ND	NA
TOC (as CH_4)	7.05 E-04	0.09	C	5.29 E-03	0.8	D
Methane	f	f	E	3.97 E-03	0.6	E
Nonmethane	f	f	E	1.32 E-03	0.2[g]	E

[a] Based on uncontrolled levels for each fuel, from References 2,6-7. When necessary, the average heating value of diesel was assumed to be 19,300 Btu/lb with a density of 7.1 lb/gallon. The power output and fuel input values were averaged independently from each other, because of the use of actual brake-specific fuel consumption (BSFC) values for each data point and of the use of data possibly sufficient to calculate only 1 of the 2 emission factors (e. g., enough information to calculate lb/MMBtu, but not lb/hp-hr). Factors are based on averages across all manufacturers and duty cycles. The actual emissions from a particular engine or manufacturer could vary considerably from these levels. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code.

[b] Dual fuel assumes 95% natural gas and 5% diesel fuel.

[c] References 8-26. Controlled NO_x is by ignition timing retard.

[d] Assumes that all sulfur in the fuel is converted to SO_2. S_1 = % sulfur in fuel oil; S_2 = % sulfur in natural gas. For example, if sulfer content is 1.5%, then S = 1.5.

[e] Assumes 100% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 70 weight % carbon in natural gas, dual-fuel mixture of 5% diesel with 95% natural gas, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 1050 Btu/scf.

[f] Based on data from 1 engine, TOC is by weight 9% methane and 91% nonmethane.

[g] Assumes that nonmethane organic compounds are 25% of TOC emissions from dual-fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Selected WebFIRE Factors
08 Jul 2013

SCC	20100102	
Level 1	Internal Combustion Engines	
Level 2	Electric Generation	
Level 3	Distillate Oil (Diesel)	
Level 4	Reciprocating	
POLLUTANT	Ethylbenzene NEI 100414	CAS 100-41-4
Primary Control UNCONTROLLED		
Emission Factor	3.070E-3 Lb per 1000 Gallons Distillate Oil (Diesel) Burned	
Quality	U Emissions Factors Applicability	
References	AB2588 Source Test Report for Diesel-fired IC Engine and Diesel-fired Boiler. (Confidential Report No. ERC-93)	
AP 42 Section		
Formula		
Notes	Emissions data are also available in lb/MMBtu.	

BOWIE POWER STATION
COOLING TOWER PM/PM_{10}/$PM_{2.5}$ EMISSIONS

Stack Parameters

Stack Height	14.0	meters
	45.9	feet
Stack Temperature	70	^{o}F
	294.26	K
Stack Exit Flowrate per Cell	1,430,000	ft^3/minute
	674.97	$meters^3$/second
Stack Exit Velocity per Cell	8.59	meters/second
	28.20	ft/second
Stack Diameter per Cell	10.0	meters
	32.81	feet

Cooling Tower Data

towers	1	
cells/tower	9	
ppm by weight TDS in blowdown	4,039	ppm_w
Drift	0.0005%	
Flowrate	127,860	gallons/minute
Capacity Factor	100%	

Cooling Tower Emissions

PARTICULATE MATTER

TDS in Blowdown (ppm_w)	4,039	ppm_w
TDS in blowdown (mg/l) [ppm_w approximately = mg/l]	4,039	mg/l
Flow of dissolved solids (lbs/gallon)	0.03	lbs/gallon
Flowrate of tower (gallons per minute)	127,860	gallons/minute
Drift %	0.0005%	
Peak Drift (gallons/minute)	0.64	gallons/minute

Pollutant	% of PM[a]	Hourly Emissions (lb/hour)	Annual Emissions (tpy)
PM		1.29	5.67
PM_{10}	67.47	0.87	3.83
$PM_{2.5}$	32.15	0.42	1.82

[a]Calculated on page 3.

BOWIE POWER STATION
COOLING TOWER PM/PM_{10}/$PM_{2.5}$ EMISSIONS

$$\text{feet} = \text{meters} \times \frac{3.281\ \text{feet}}{\text{meters}}$$

$$K = \left[\frac{5}{9}\,(^{\circ}F-32)\right] + 273.15$$

$$\frac{\text{cubic meters}}{\text{second}} = \frac{\text{cubic feet}}{\text{minute}} \times \frac{\text{cubic meters}}{35.31\ \text{cubic feet}} \times \frac{\text{minute}}{60\ \text{seconds}}$$

Flowrate = Exit Velocity x Area

$$\text{Exit velocity}\ \left(\frac{\text{meters}}{\text{second}}\right) = \frac{\text{Flowrate (cubic meters/second)}}{\text{PI} \times (\text{stack diameter (meters)}/2)^2}$$

$$\frac{\text{feet}}{\text{second}} = \frac{\text{meters}}{\text{second}} \times \frac{3.281\ \text{feet}}{\text{meter}}$$

For water ppm = mg/liter

lb/gallon is calculated as follows:

$$\frac{\text{lb}}{\text{gallon}} = \frac{\text{mg}}{\text{liter}} \times \frac{3.79\ \text{liters}}{\text{gallons}} \times \frac{\text{grams}}{1000\ \text{mg}} \times \frac{\text{lb}}{453.69\ \text{grams}}$$

Peak drift in gallons/minute is calculated as follows:

$$\text{drift}\ \frac{\text{gallons}}{\text{minute}} = \text{tower flowrate}\ \frac{\text{gallons}}{\text{minute}} \times \frac{\%\ \text{drift}}{100}$$

Emissions from Tower in lbs/hour is calculated as follows:

$$\frac{\text{lbs}}{\text{hour}} = \text{dissolved solids}\ \frac{\text{lbs}}{\text{gallon}} \times \text{drift}\ \frac{\text{gallons}}{\text{minute}} \times \frac{60\ \text{minutes}}{\text{hour}}$$

Particulate Emissions from Tower in tons/year is calculated as follows:

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{hour}} \times \frac{8760\ \text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}} \times \text{capacity factor}$$

PM_{10} and $PM_{2.5}$ Emissions are Calculated as follows:

$$PM_{10}\ \text{Emissions} = \text{PM Emissions} \times \frac{\%\ PM_{10}}{100}$$

$$PM_{2.5}\ \text{Emissions} = \text{PM Emissions} \times \frac{\%\ PM_{2.5}}{100}$$

BOWIE POWER STATION
COOLING TOWER PM/PM_{10}/$PM_{2.5}$ EMISSIONS

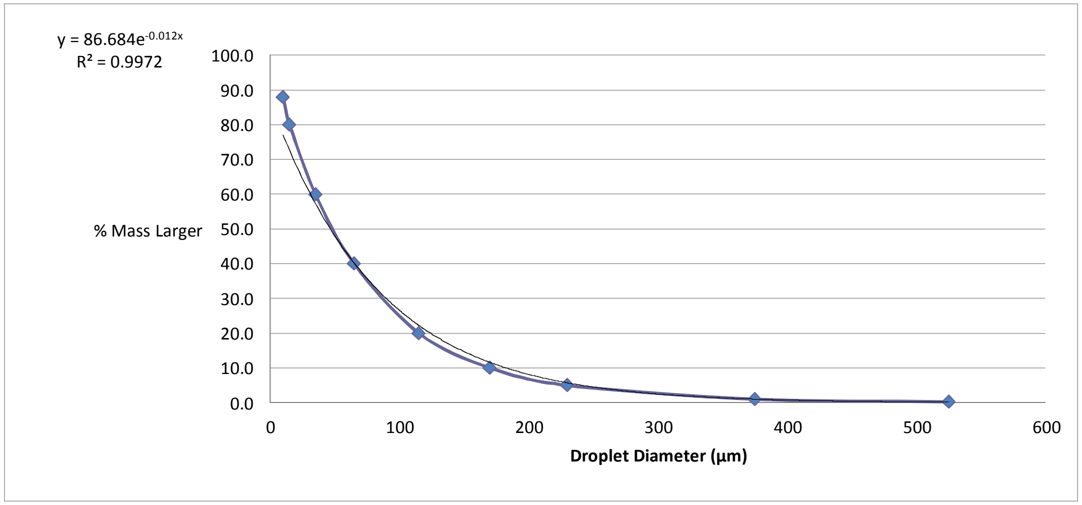
Particle Size Distribution

TDS in blowdown	4,039	ppmw

Droplet Diameter (µm)[a]	**% Mass Larger[a]**	**% Mass Smaller**	**Solid Particle Diameter (µm)**
525	0.2	99.8	64.29
375	1.0	99.0	45.92
230	5.0	95.0	28.16
170	10.0	90.0	20.82
115	20.0	80.0	14.08
65	40.0	60.0	7.96
35	60.0	40.0	4.29
15	80.0	20.0	1.84
10	88.0	12.0	1.22

81.67	32.5	67.5	10
20.42	67.8	32.2	2.5

[a]From "Cooling Tower Drift Mass Distribution, Excel Drift Eliminators" for Marley TU10 and TU12 drift eliminators



BOWIE POWER STATION
COOLING TOWER PM/PM_{10}/$PM_{2.5}$ EMISSIONS

% Mass Smaller = 100 - % Mass Larger

Equation 7 from "Calculating Realistic PM10 Emissions from Cooling Towers", Joel Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2, pages 127-130, July 2002:

Diameter of Solid Particle µm = Diameter of Droplet µm x [Total Dissolved Solids ppmw x (Density of Water/Density of TDS)]$^{1/3}$

Density of Water = 1.0 $\frac{g}{cm^3}$

Density of TDS = Density of Sodium Chloride = 2.2 $\frac{g}{cm^3}$

Diameter of Solid Particle µm = Diameter of Droplet µm x [Total Dissolved Solids $\frac{\text{parts}}{\text{1,000,000 parts}}$ x (1.0 g/cm^3/2.2 g/cm^3)]$^{1/3}$

To Determine % Smaller than 10µm and less than 2.5µm, first calculate the droplet size that corresponds to the particle size:

$$\text{Diameter of Droplet µm} = \frac{\text{Diameter of Solid Particle µm}}{[\text{Total Dissolved Solids } \frac{\text{parts}}{\text{1,000,000 parts}} \text{ x } (1.0\ g/cm^3/2.2g/cm^3)]\text{\^{}}(1/3)}$$

Then graph the cooling tower data to obtain the relationship between droplet size and % mass larger:

This results in an exponential curve with the form

% Mass Larger = 86.684e$^{-(0.012\text{x droplet diameter µm})}$

Then calculate % Mass Smaller = 100 - % Mass Larger

ESTIMATED WATER QUALITIES

	Stream	Supply / Service Water		Demin Water		DW Rejects		Softened Water		Cooling Twr. Blowdown		Evap. Cooler Blowdown	
	Diagram ID	A, B, R		I,J,K,Y, Z		H, X		W,G,M,N		U		P	
CATIONS		as such	as CaCO3	as such	as CaCO3	as such	as CaCO3	as such	as CaCO3	as such	as CaCO3	as such	as CaCO3
Ca	2.50	35	88	0.4	0.9	140	350	20	50	360	900	100	250
Mg	4.11	6.00	25	0.1	0.2	24	99	5	21	90	370	25	103
Na	2.17	55	119	0.6	1.2	220	477	43	93	774	1680	215	467
K	1.28	3.0	4	0.0	0.0	12	15	3	4	54	69	15	19
Total			235		2		941		168		3019		839
ANIONS													
M Alk			130		1		520		100		150		500
SO4	1.04	52	54	0.1	0	208	216	29	30	2109	2193	145	151
Cl	1.41	36	51	0.0	0	144	203	25	35	450	635	125	176
NO3	0.81		0	0.0	0	0	0	3	2	54	44	15	12
CO2	1.14									0		0	
SiO2	0.84	32.0		0.1		128		7		126		35	
Total			235		1		939		168		3021		839
HCO3	0.82												
CO3								50					
OH								50					
P Alk													
pH		8.1		6.0 - 8.0		8.5		11.0		8.0		8.0	
Spec Cond		400		<1.0		1354		209.6		6213.4		1047.9	
TDS		260		1.2		880		136		4039		681	
Total Hardness			112		1		448		71		1270		353
Turbidity	NTU												
Color													
Ortho Phosphate		0.01		0.00		0.04							
Total Phosphate		0.05				0.20							
F		0.79				3.16		0.85		15.30		4.25	
Ba		0.08				0.31		0.08		1.40		0.39	
Fe				0.00	0.00			0.00		0.00		0.00	
Mn		0.003				0.01		0.00		0.05		0.02	
NH3		0.30				1.20		0.30		5.40		1.50	
Oil/Grease													
TSS								2.00		36.00			
BOD5		0											
COD		0											
Trace Metals													
Aluminum	ppb	100		0.30		399.64		100		1800		500.00	
Antimony	ppb	2		0.01		7.99		2		36		10.00	
Arsenic	ppb	3		0.01		11.99		3		54		15.00	
Beryllium	ppb	0.5		0.00		2.00		1		9		2.50	
Cadmium	ppb	2		0.01		7.99		2		36		10.00	
Chromium	ppb	5		0.02		19.98		5		90		25.00	
Copper	ppb	3.6		0.01		14.39		4		65		18.00	
Lead	ppb	2		0.01		7.99		2		36		10.00	
Mercury	ppb	0.2		0.00		0.80		0		4		1.00	
Nickel	ppb	5		0.02		19.98		5		90		25.00	
Selenium	ppb	2		0.01		7.99		2		36		10.00	
Silver	ppb	1		0.00		4.00		1		18		5.00	
Strontium	ppb	410		1.23		1638.52		410		7380		2050.00	
Vanadium	ppb	10		0.03		39.96		10		180		50.00	
Zinc	ppb	50		0.15		199.82		50		900		250.00	
Cl Resid (ppm)	Free												
	Total												

Notes:
1) 7 ppm silica assumed from softener
2) Cooling tower silica limit is 150 ppm

Rev	DESCRIPTION	Dwn	Chk	App	Date
E	Updated water usage, quality	BMC			05-01-08
D	Added Additional HB Cases	BMC			04-21-08
C	Added Demin to Evap Cooler	BMC			04-08-08
B	Deleted HP steam PAG cases	TRA			03-29-08
A	Issued for Review	BMC			03-10-08

BOWIE POWER STATION, LLC
500 MW PHASE 1

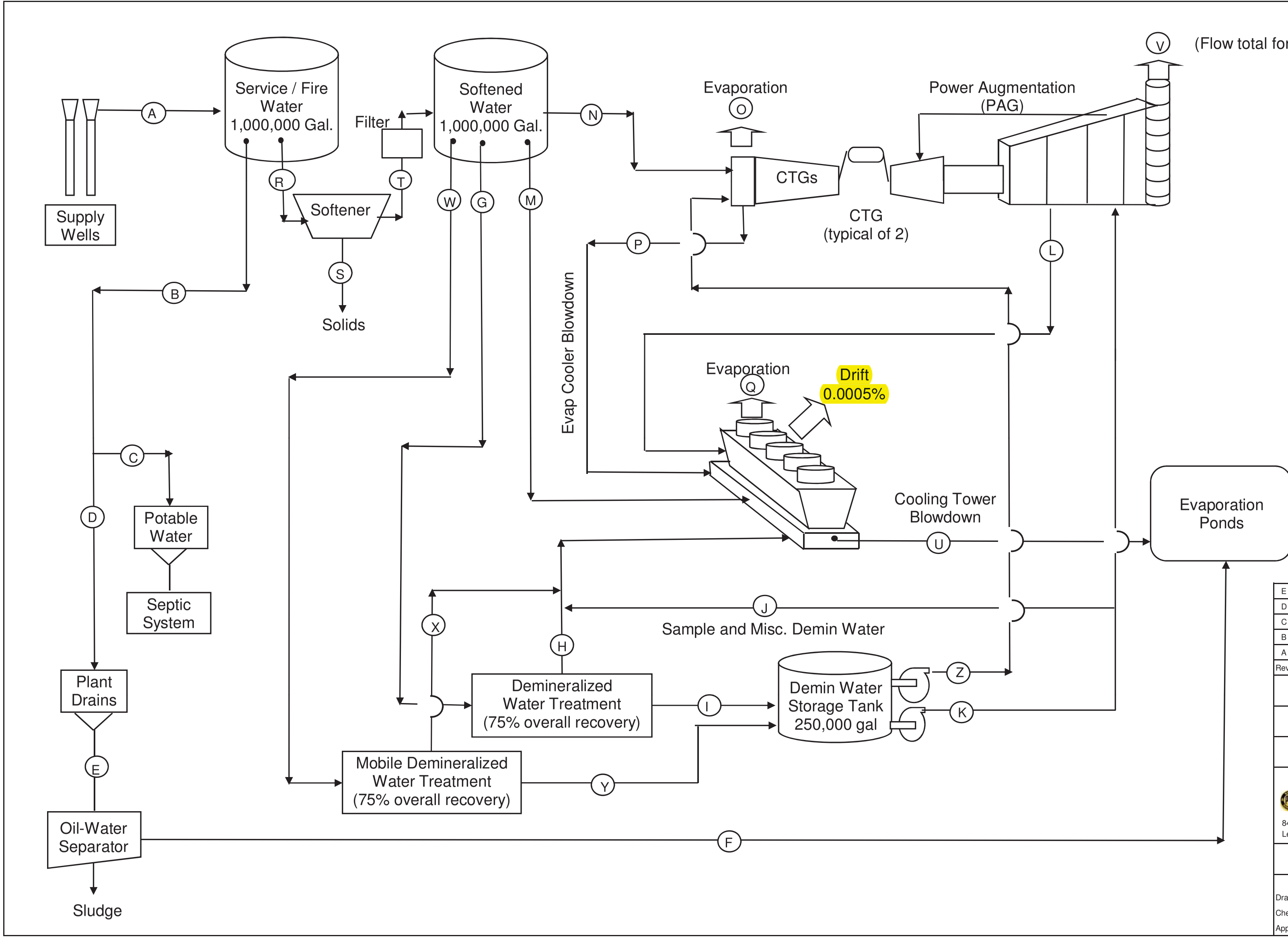
SOUTHWESTERN Power Group LLC

MMR

Kiewit
8455 Lenexa Drive
Lenexa, Kansas 66214

WATER BALANCE FLOW VALUES

	by	date	DRAWING NUMBER
Drawn	BMC	03-10-08	2008-022-WB-004
Checked			
Approved			



Rev	DESCRIPTION	Dwn	Chk	App	Date
E	Updated water usage, quality	BMC			05-01-08
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B	Deleted HP steam PAG cases	TRA			03-29-08
A	Issued for Review	BMC			03-10-08

BOWIE POWER STATION, LLC
500 MW PHASE 1

SOUTHWESTERN Power Group LLC

MMR

Kiewit
8455 Lenexa Drive
Lenexa, Kansas 66214

WATER BALANCE FLOW DIAGRAM

	by	date	DRAWING NUMBER
Drawn	BMC	03-10-08	2008-022-WB-001
Checked			
Approved			

COOLING TOWER DRIFT MASS DISTRIBUTION
Excel Drift Eliminators

The following table represents the predicted mass distribution of drift particle size for cooling tower drift dispersed from Marley TU10 and TU12 Excel Drift Eliminators properly installed in a cooling tower.

Mass in Particles (%)		Droplet Size (Microns)
0.2	Larger Than	525
1.0	Larger Than	375
5.0	Larger Than	230
10.0	Larger Than	170
20.0	Larger Than	115
40.0	Larger Than	65
60.0	Larger Than	35
80.0	Larger Than	15
88.0	Larger Than	10

How to read table: Example – 0.2% of the drift will have particle sizes larger than 525 microns.

Marley guarantees the data above for properly installed, undamaged drift eliminators in ‘like-new’ condition.

Calculating Realistic PM_{10} Emissions from Cooling Towers

Abstract No. 216 Session No. AM-1b

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ABSTRACT

Particulate matter less than 10 micrometers in diameter (PM_{10}) emissions from wet cooling towers may be calculated using the methodology presented in EPA's AP-42[1] , which assumes that all total dissolved solids (TDS) emitted in "drift" particles (liquid water entrained in the air stream and carried out of the tower through the induced draft fan stack.) are PM_{10}. However, for wet cooling towers with medium to high TDS levels, this method is overly conservative, and predicts significantly higher PM_{10} emissions than would actually occur, even for towers equipped with very high efficiency drift eliminators (e.g., 0.0006% drift rate). Such over-prediction may result in unrealistically high PM_{10} modeled concentrations and/or the need to purchase expensive Emission Reduction Credits (ERCs) in PM_{10} non-attainment areas. Since these towers have fairly low emission points (10 to 15 m above ground), over-predicting PM_{10} emission rates can easily result in exceeding federal Prevention of Significant Deterioration (PSD) significance levels at a project's fenceline. This paper presents a method for computing realistic PM_{10} emissions from cooling towers with medium to high TDS levels.

INTRODUCTION

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Wet, or evaporative, cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers, for example, steam condensers. Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Because the drift droplets contain the same chemical impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets may be classified as an emission. The magnitude of the drift loss is influenced by the number and size of droplets produced within the tower, which are determined by the tower fill design, tower design, the air and water patterns, and design of the drift eliminators.

AP-42 METHOD OF CALCULATING DRIFT PARTICULATE

EPA's AP-42[1] provides available particulate emission factors for wet cooling towers, however, these values only have an emission factor rating of "E" (the lowest level of confidence acceptable). They are also rather high, compared to typical present-day manufacturers' guaranteed drift rates, which are on the order of 0.0006%. (Drift emissions are typically expressed as a percentage of the cooling tower water circulation rate). AP-42 states that "a *conservatively high* PM_{10} emission factor can be obtained by (a) multiplying the total liquid drift factor by the TDS fraction in the circulating water, and (b) assuming that once the water evaporates, all remaining solid particles are within the PM_{10} range." (Italics per EPA).

If TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS for the make-up water and multiplying it by the cooling tower cycles of concentration. [The cycles of concentration is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water.]

Using AP-42 guidance, the total particulate emissions (PM) (after the pure water has evaporated) can be expressed as:

$$PM = \text{Water Circulation Rate} \times \text{Drift Rate} \times \text{TDS} \qquad [1]$$

For example, for a typical power plant wet cooling tower with a water circulation rate of 146,000 gallons per minute (gpm), drift rate of 0.0006%, and TDS of 7,700 parts per million by weight (ppmw):

$$PM = 146{,}000 \text{ gpm} \times 8.34 \text{ lb water/gal} \times 0.0006/100 \times 7{,}700 \text{ lb solids}/10^6 \text{ lb water} \times 60 \text{ min/hr} = \underline{3.38 \text{ lb/hr}}$$

On an annual basis, this is equivalent to almost 15 tons per year (tpy). Even for a state-of-the-art drift eliminator system, this is not a small number, especially if assumed to all be equal to PM_{10}, a regulated criteria pollutant. However, as the following analysis demonstrates, only a very small fraction is actually PM_{10}.

COMPUTING THE PM_{10} FRACTION

Based on a representative drift droplet size distribution and TDS in the water, the amount of solid mass in each drop size can be calculated. That is, for a given initial droplet size, assuming that the mass of dissolved solids condenses to a spherical particle after all the water evaporates, and assuming the density of the TDS is equivalent to a representative salt (e.g., sodium chloride), the diameter of the final solid particle can be calculated. Thus, using the drift droplet size distribution, the percentage of drift mass containing particles small enough to produce PM_{10} can be calculated. This method is conservative as the final particle is assumed to be perfectly spherical; hence as small a particle as can exist.

The droplet size distribution of the drift emitted from the tower is critical to performing the analysis. Brentwood Industries, a drift eliminator manufacturer, was contacted and agreed to provide drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull[2], 1999). The data consist of water droplet size distributions for a drift eliminator that achieved a tested drift rate of 0.0003 percent. As we are using a 0.0006 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate would produce smaller droplets, therefore, this size distribution data can be assumed to be <u>conservative</u> for predicting the fraction of PM_{10} in the total cooling tower PM emissions.

In calculating PM_{10} emissions the following assumptions were made:

- Each water droplet was assumed to evaporate shortly after being emitted into ambient air, into a single, solid, spherical particle.
- Drift water droplets have a density (ρ_w) of water; $1.0\ \text{g/cm}^3$ or $1.0 * 10^{-6}\ \mu g/\mu m^3$.
- The solid particles were assumed to have the same density (ρ_{TDS}) as sodium chloride, (i.e., 2.2 g/cm^3).

Using the formula for the volume of a sphere, $V = 4\pi r^3/3$, and the density of pure water, $\rho_w = 1.0\ \text{g/cm}^3$, the following equations can be used to derive the solid particulate diameter, D_p, as a function of the TDS, the density of the solids, and the initial drift droplet diameter, D_d :

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3 \qquad [2]$$

$$\text{Mass of solids in drift droplet} = (\text{TDS})(\rho_w)(\text{Volume of drift droplet}) \qquad [3]$$

substituting,

$$\text{Mass of solids in drift} = (\text{TDS})(\rho_w)\,(4/3)\pi(D_d/2)^3 \qquad [4]$$

Assuming the solids remain and coalesce after the water evaporates, the mass of solids can also be expressed as:

$$\text{Mass of solids} = (\rho_{TDS})\ (\text{solid particle volume}) = (\rho_{TDS})(4/3)\pi(D_p/2)^3 \qquad [5]$$

Equations [4] and [5] are equivalent:

$$(\rho_{TDS})(4/3)\pi(D_p/2)^3 = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [6]$$

Solving for D_p:

$$D_p = D_d\ [(\text{TDS})(\rho_w/\rho_{TDS})]^{1/3} \qquad [7]$$

Where,

TDS is in units of ppmw
D_p = diameter of solid particle, micrometers (μm)
D_d = diameter of drift droplet, μm

Using formulas [2] – [7] and the particle size distribution test data, Table 1 can be constructed for drift from a wet cooling tower having the same characteristics as our example; 7,700 ppmw TDS and a 0.0006% drift rate. The first and last columns of this table are the particle size distribution derived from test results provided by Brentwood Industries. Using straight-line interpolation for a solid particle size 10 μm in diameter, we conclude that approximately <u>14.9 percent</u> of the mass emissions are equal to or smaller than PM_{10}. The balance of the solid particulate are particulate greater than 10 μm. Hence, PM_{10} emissions from this tower would be equal to PM emissions x 0.149, or 3.38 lb/hr x 0.149 = 0.50 lb/hr. The process is repeated in Table 2, with all parameters equal except that the TDS is 11,000 ppmw. The result is that approximately 5.11 percent are smaller at 11,000 ppm. Thus, while total PM emissions are larger by virtue of a higher TDS, overall PM_{10} emissions are actually lower, because more of the solid particles are larger than 10 μm.

Table 1. Resultant Solid Particulate Size Distribution (TDS = 7700 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4189	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65450	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381704	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150347	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767146	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305995	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137167	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449298	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510322	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449847	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097336	1.13E+02	8.71E-01	395840.67	91.098	100.000

[1] Bracketed numbers refer to equation number in text.

The percentage of PM_{10}/PM was calculated for cooling tower TDS values from 1000 to 12000 ppmw and the results are plotted in Figure 1. Using these data, Figure 2 presents predicted PM_{10} emission rates for the 146,000 gpm example tower. As shown in this figure, the PM emission rate increases in a straight line as TDS increases, however, the PM_{10} emission rate increases to a maximum at around a TDS of 4000 ppmw, and then begins to decline. The reason is that at higher TDS, the drift droplets contain more solids and therefore, upon evaporation, result in larger solid particles for any given initial droplet size.

CONCLUSION

The emission factors and methodology given in EPA's AP-42[1] Chapter 13.4 *Wet Cooling Towers*, do not account for the droplet size distribution of the drift exiting the tower. This is a critical factor, as more than 85% of the mass of particulate in the drift from most cooling towers will result in solid particles larger than PM_{10} once the water has evaporated. Particles larger than PM_{10} are no longer a regulated air pollutant, because their impact on human health has been shown to be insignificant. Using reasonable, conservative assumptions and a realistic drift droplet size distribution, a method is now available for calculating realistic PM_{10} emission rates from wet mechanical draft cooling towers equipped with modern, high-efficiency drift eliminators and operating at medium to high levels of TDS in the circulating water.

Table 2. Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4189	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65450	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381704	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150347	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767146	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305995	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137167	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449298	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510322	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449847	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097336	1.13E+02	1.24E+00	565486.68	102.599	100.000

Figure 1: Percentage of Drift PM that Evaporates to PM10

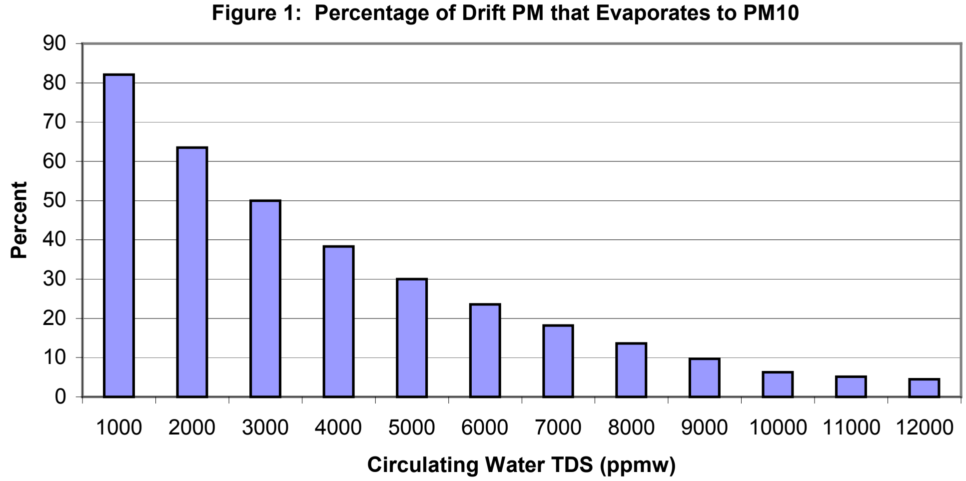
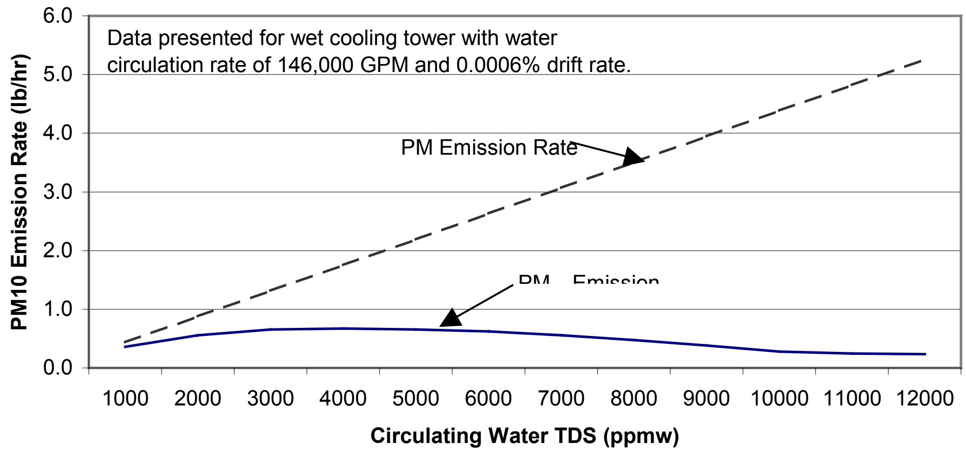


Figure 2: PM_{10} Emission Rate vs. TDS



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1. EPA, 1995. Compilation of Air pollutant Emission Factors, AP-42 Fifth edition, Volume I: *Stationary Point and Area Sources*, Chapter 13.4 Wet Cooling Towers, http://www.epa.gov/ttn/chief/ap42/, United States Environmental Protection Agency, Office of Air Quality Planning and Standards, January.

2. Aull, 1999. Memorandum from R. Aull, Brentwood Industries to J. Reisman, Greystone, December 7, 1999.

KEY WORDS

Drift
Drift eliminators
Cooling tower
PM_{10} emissions
TDS

BOWIE POWER STATION
COOLING TOWER HAP EMISSIONS

Cooling Tower Capacity Factor	100%

CHLOROFORM
Cooling Towers

Corrected Emission Factor for Chloroform (kg/10^9 liters cooling water flow) From EPA document "Locating and Estimating Air Emissions from Sources of Chloroform, page 58	2.3	kg/10^9 liters
Cooling water flow (gallons per minute)	127,860	gallons/minute
Chloroform emissions from tower (lb/hour)	0.15	lb/hour
Annual cooling tower chloroform emissions (tons/year)	0.64	tons/year

BLOWDOWN EMISSIONS

Drift	0.64	gallons/minute

	Blowdown Concentrations[a]		Emissions	
	ppb	lb/gallon	lb/hour	tons/year
Antimony	36	3.00E-07	1.15E-05	5.05E-05
Arsenic	54	4.51E-07	1.73E-05	7.57E-05
Beryllium	9	7.51E-08	2.88E-06	1.26E-05
Cadmium	36	3.00E-07	1.15E-05	5.05E-05
Chromium	90	7.51E-07	2.88E-05	1.26E-04
Lead	36	3.00E-07	1.15E-05	5.05E-05
Mercury	4	3.34E-08	1.28E-06	5.61E-06
Nickel	90	7.51E-07	2.88E-05	1.26E-04
Selenium	36	3.00E-07	1.15E-05	5.05E-05

[a]Provided in "Water Balance Flow Values", Kiewit Power Engineers

Cooling tower flow is from spreadsheet titled "Cooling Tower PM/PM_{10}/$PM_{2.5}$ Emissions"

Chloroform

$$\frac{lb}{hour} = \frac{kg}{10^9\ liters} \times \frac{3.785\ liters}{gallon} \times \frac{1000\ g}{kg} \times \frac{lb}{453.59\ grams} \times \frac{gallons}{minute} \times \frac{60\ minutes}{hour}$$

$$\frac{tons}{year} = \frac{lb}{hour} \times \frac{8760\ hours}{year} \times \frac{tons}{2000\ lb} \times \text{capacity factor}$$

Drift value comes from spreadsheet titled "Cooling Tower PM/PM_{10}/$PM_{2.5}$ Emissions"

For water, ppb = $\frac{\mu g}{liter}$

$$\frac{lb}{gallon} = \frac{\mu g}{liter} \times \frac{3.785\ liters}{gallons} \times \frac{grams}{10^6\ \mu g} \times \frac{lb}{453.59\ grams}$$

$$\frac{lbs}{hour} = \text{solids}\ \frac{lbs}{gallon} \times \text{drift}\ \frac{gallons}{minute} \times \frac{60\ minutes}{hour}$$

Emissions Per Tower in tons/year is calculated as follows:

$$\frac{tons}{year} = \frac{lb}{hour} \times \frac{8760\ hours}{year} \times \frac{tons}{2000\ lb}$$

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/4-84-007c
March 1984

AIR

EPA

LOCATING AND ESTIMATING AIR EMISSIONS FROM SOURCES OF CHLOROFORM

Emissions--

Once-through Cooling Systems - Once-through cooling systems are used in approximately 60 percent of nonnuclear steam electric plants and in a total of 11 nuclear power plants in the United States.[40,41] The amount of chloroform formed in once-through cooling systems can be calculated based on the volume of cooling water used and the chloroform concentration resulting from chlorination. Chlorination has been shown to produce 0.41 kilograms (kg) of chloroform per 10g liters of cooling water.[39] Assuming that all of the chloroform in the cooling water evaporates, the chloroform emission factor is 0.41 kg/10^9 liters of cooling water.

Recirculating Cooling Systems - Chloroform production rates resulting from chlorination in two recirculating cooling systems were measured at 2.4 and 3.6 mg chloroform per liter cooling water flow.[39] With approximately 75 percent evaporating at the cooling tower[39] the average chloroform emission factor for cooling towers is 2.3 kg/10^6 liters of cooling water. Assuming all of the remaining chloroform discharged in cooling tower blowdown evaporates from the receiving water, the chloroform emission factor is 0.75 kg/10^6 liters of cooling water.

Source Locations--

The SIC code for establishments engaged in the generation of electricity for sale is 4911.

Drinking Water

The occurrence and formation of chloroform in finished drinking water has been well documented. Chloroform may be present in the raw water as a result of industrial effluents containing the chemical. In addition, chloroform is formed from the reaction of chlorine with humic materials. Humic materials are acidic components derived from the decomposition of organic matter. Examples include humic acid, fulvic acid, and hymatomelanic acid. The amount of chloroform generated in drinking water is a function of both the amount of humic material present in the raw water and the chlorine feed. The chlorine feed is adjusted to maintain a fairly constant 2.0 to 2.5 ppm chlorine residual and reflects changes in the total oxidizable dissolved organics and the rates of various oxidation reactions. Although there is a higher organic content in raw water during the winter months, the more

Chloroform Emissions for Cooling Towers

Personal communication with EPA by Russ Henning, Radian International. The chloroform emission factor for cooling towers from the L&E document should be 2.3/0.75 kg/E9 liters not E6 liters.

BOWIE POWER STATION
EVAPORATION POND CHLOROFORM EMISSIONS

Chloroform Emissions

Corrected Emission Factor for Chloroform (kg/10^9 liters cooling water flow) From EPA document "Locating and Estimating Air Emissions from Sources of Chloroform, page 58	0.75
Flow to Cooling Ponds from all Cooling Towers combined (gallons per minute)	131
Chloroform emissions from tower (lb/hour)	4.92E-05
Annual chloroform emissions (tons/year) for 8760 hours/year	2.15E-04

$$\frac{\text{lb}}{\text{hour}} = \frac{\text{kg}}{10^9\ \text{liters}} \times \frac{3.785\ \text{liters}}{\text{gallon}} \times \frac{1000\ \text{g}}{\text{kg}} \times \frac{\text{lb}}{453.59\ \text{grams}} \times \frac{\text{gallons}}{\text{minute}} \times \frac{60\ \text{minutes}}{\text{hour}}$$

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{hour}} \times \frac{8760\ \text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\ \text{lb}}$$

BOWIE POWER STATION
ANNUAL GREENHOUSE GAS EMISSIONS

Number of Turbines and Duct Burners	2
Number of Auxiliary Boilers	1
Number of Emergency Fire Pumps	1
Number of Circuit Breakers	5

	SF_6 Contents (lbs)
Circuit Breaker - Each	360

Turbine Heat Input - 59°F Ambient

Operating Scenario	Heat Input, mmBtu/hour HHV
100% Load	1615.87
Minimum Compliance Load	1020.80

Duct Burner Heat Input	420	mmBtu/hour HHV

Emission Unit	Heat Input Rate (mmBtu/hour)	Hours of Operation (hours/year)	Heat Input Rate (mmBtu/year)	Emission Factor				Emissions Each Piece of Equipment (tons/year)			
				CO_2[a] (kg/mmBtu)	CH_4[b] (kg/mmBtu)	N_2O[b] (kg/mmBtu)	SF_6 (% Leak Rate)[c]	CO_2	CH_4	N_2O	SF_6
Turbines - Startup	1020.80	325.0	331,760.00					19,392.88	0.37	0.04	
Turbines and Duct Burners - Duct Firing	2035.87	4224	8,599,514.88					502,680.77	9.48	0.95	
Turbines - No Power Augmentation, No Duct Firing	1615.87	3681.8	5,949,229.37	53.02	1.00E-03	1.00E-04		347,759.53	6.56	0.66	
Turbines - Shutdown	1020.80	91.3	93,148.00					5,444.92	0.10	0.01	
Turbines and Duct Burners - Oxidation Catalyst Conversion of CO								248.00			
Turbines and Duct Burners - Total								875,526.11	16.51	1.65	
Auxiliary Boiler	50	450	22,500	53.02	1.00E-03	1.00E-04		1,315.23	0.02	0.002	
Emergency Fire Pump	1.84	100	184	73.96	3.00E-03	6.00E-04		14.97	6.07E-04	1.21E-04	
Circuit Breakers							0.1%				1.80E-04

[a]From 40 Code of Federal Regulations 98, Table C-1, "Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel".

[b]From 40 Code of Federal Regulations 98, Table C-2, "Default CH_4 and N_2O Emission Factors for Various Types of Fuel".

[c]From *Electric Power Substation Engineering* , 2nd Edition, 2007, Edited by John D. McDonald. "Field checks of GIS [gas-insulated substations] in service after many years of service indicate that a leak rate objective lower than 0.1% per year is obtainable".

Emission Unit	CO_2e Emissions per Piece of Equipment (tons/year)	CO_2e Emissions Total (tons/year)
Turbines and Duct Burner	876,384.55	1,752,769.09
Auxiliary Boiler	1,316.52	1,316.52
Emergency Fire Pump	15.02	15.02
Circuit Breakers	4.30	21.51
TOTAL	877,720.38	1,754,122.14

Oxidation Catalyst CO_2 Emissions

	Uncontrolled CO Emissions (tons/year)	Controlled CO Emissions (tons/year)	CO Converted by Oxidation Catalyst (tons/year)	CO_2 Emissions from Oxidation Catalyst Conversion from CO (tons/year)
Turbine and Duct Burner - Each (tons/year)	238.36	80.54	157.82	248.00

	CO_2	CH_4	N_2O	SF_6
Global Warming Potential[d]	1	21	310	23,900

[d]From 40 CFR 98, Table A-1 "Global Warming Potentials"

BOWIE POWER STATION
ANNUAL GREENHOUSE GAS EMISSIONS

Annual greenhouse gas (GHG) Emissions for the Combustion Turbines and Duct Burners are calculated in the same manner as emissions from the criteria pollutants - at an annual average ambient temperature of 59°F.

For turbine startup and shutdown, a heat input equivalent to 50% load has been assumed.

$$\frac{mmBtu}{year} = \frac{mmBtu}{hour} \times \frac{hours}{year}$$

$$\text{Combustion Emissions } \frac{tons}{year} = \text{Fuel Use } \frac{mmBtu}{year} \times \frac{kg}{mmBtu} \times \frac{2.205\ lb}{kg} \times \frac{tons}{2000\ lb}$$

Turbine and Duct Burner CO Controlled and Uncontrolled Emissions from spreadsheet "Turbine and Duct Burner Annual Emissions"

$$\text{CO Converted by Oxidation Catalyst } \frac{tons}{year} = \text{Uncontrolled CO Emissions } \frac{tons}{year} - \text{Controlled CO Emissions } \frac{tons}{year}$$

$$\text{Oxidation Catalyst } CO_2 \text{ Emissions } \frac{tons}{year} = \text{CO Converted by Oxidation Catalyst } \frac{tons}{year} \times \frac{44 \text{ tons/ton moles of } CO_2}{28 \text{ tons/ton moles of CO}}$$

$$\text{Circuit Breaker } SF_6 \text{ Emissions } \frac{tons}{year} = SF_6 \text{ Content lb} \times \frac{\%\ \text{leak rate}}{year} \times \frac{tons}{2000\ lb}$$

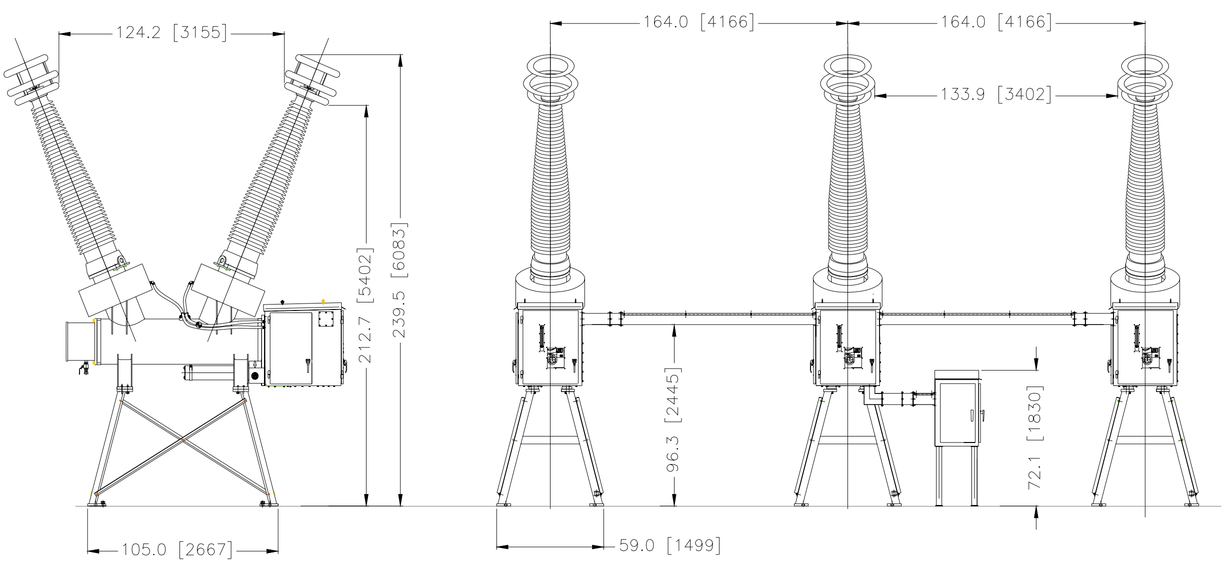
$$CO2_e \text{ Emissions } \frac{tons}{year} = (CO_2 \text{ Emissions } \frac{tons}{year} \times CO_2 \text{ Global Warming Potential}) + (CH_4 \text{ Emissions } \frac{tons}{year} \times CH_4 \text{ Global Warming Potential}) + (N_2O \text{ Emissions } \frac{tons}{year} \times N_2O \text{ Global Warming Potential})$$
$$+ (SF_6 \text{ Emissions } \frac{tons}{year} \times SF_6 \text{ Global Warming Potential})$$

$$\text{Emissions Total } \frac{tons}{year} = \text{Emissions Each Piece of Equipment } \frac{tons}{year} \times \#\text{ of Pieces of Equipment}$$

Specifications

HHI / HHIR Series	362kV 40/50/63kA	362kV 40/50/63kA w/ Pre-insertion resistor
Rated Maximum Voltage (kV)	362	362
BIL (kV crest)	1300	1300
60 Hz withstand (kV)	555	555
Continuous Current (A)	3000 / 4000 / 5000	3000 / 4000 / 5000
Interrupting Current (kA)	40 / 50 / 63*	40 / 50 / 63*
Interrupting time	2 cycles	2 cycles
Total weight (lbs) 40kA - 50kA	27,500	34,987
Total weight (lbs) 63kA	29,710	37,200
Weight of SF6 Gas (lbs)	360	562
Pre-insertion resistor (Ohms)	N/A	520
	* Capacitance required for 63kA	

Outline Drawing



Outline drawing for information purposes only - Not to be used for construction

Model shown: 362kV 40kA

7250 McGinnis Ferry Road ◆ Suwanee, Georgia 30024

Phone: 770-495-1755 ◆ Fax: 770-623-9214 ◆ Toll Free: 866-362-0798

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of July 3, 2013

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart C—General Stationary Fuel Combustion Sources

TABLE C-1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO_2/mmBtu
(Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.135	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.069	62.64
Ethanol	0.084	68.44
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74

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Subpart C—General Stationary Fuel Combustion Sources

TABLE C-2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the “Energy Industry” or “Manufacturing Industries and Construction”. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC “Energy Industry” category may employ a value of 1g of CH_4/mmBtu.

[75 FR 79154, Dec. 17, 2010]

Electric Power Engineering Handbook

Second Edition

ELECTRIC POWER SUBSTATIONS ENGINEERING

Second Edition

Edited by

John D. McDonald

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the SF_6 in GIS. There are some reactive decomposition byproducts formed because of the interaction of sulfur and fluorine ions with trace amounts of moisture, air, and other contaminants. The quantities formed are very small. Molecular sieve absorbents inside the GIS enclosure eliminate these reactive byproducts over time. SF_6 is supplied in 50 kg gas cylinders in a liquid state at a pressure of about 6000 kPA for convenient storage and transport.

Gas handling systems with filters, compressors, and vacuum pumps are commercially available. Best practices and the personnel safety aspects of SF_6 gas handling are covered in international standards [9].

The SF_6 in the equipment must be dry enough to avoid condensation of moisture as a liquid on the surfaces of the solid epoxy support insulators because liquid water on the surface can cause a dielectric breakdown. However, if the moisture condenses as ice, the breakdown voltage is not affected. So dew points in the gas in the equipment need to be below about $-10°C$. For additional margin, levels of less than 1000 ppmv of moisture are usually specified and easy to obtain with careful gas handling. Absorbents inside the GIS enclosure help keep the moisture level in the gas low even though over time moisture will evolve from the internal surfaces and out of the solid dielectric materials [10].

Small conducting particles of millimeter size significantly reduce the dielectric strength of SF_6 gas. This effect becomes greater as the pressure is raised past about 600 kPA absolute [11]. The particles are moved by the electric field, possibly to the higher field regions inside the equipment or deposited along the surface of the solid epoxy support insulators—leading to dielectric breakdown at operating voltage levels. Cleanliness in assembly is therefore very important for GIS. Fortunately, during the factory and field power frequency high-voltage tests, contaminating particles can be detected as they move and cause small electric discharges (partial discharge) and acoustic signals—they can then be removed by opening the equipment. Some GIS equipment is provided with internal "particle traps" that capture the particles before they move to a location where they might cause breakdown. Most GIS assemblies are of a shape that provides some "natural" low electric-field regions where particles can rest without causing problems.

SF_6 is a strong greenhouse gas that could contribute to global warming. At an international treaty conference in Kyoto in 1997, SF_6 was listed as one of the six greenhouse gases whose emissions should be reduced. SF_6 is a very minor contributor to the total amount of greenhouse gases due to human activity, but it has a very long life in the atmosphere (half life is estimated at 3200 y), so the effect of SF_6 released to the atmosphere is effectively cumulative and permanent. The major use of SF_6 is in electrical power equipment. Fortunately, in GIS the SF_6 is contained and can be recycled. By following the present international guidelines for the use of SF_6 in electrical equipment [12], the contribution of SF_6 to global warming can be kept to less than 0.1% over a 100 y horizon. The emission rate from use in electrical equipment has been reduced over the last decade. Most of this effect has been due to simply adopting better handling and recycling practices. Standards now require GIS to leak less than 0.5% per year. The leakage rate is normally much lower. Field checks of GIS in service after many years of service indicate that a leak rate objective lower than 0.1% per year is obtainable, and is now offered by most manufacturers. Reactive, liquid (oil), and solid contaminants in used SF_6 are easily removed by filters, but inert gaseous contaminants such as oxygen and nitrogen are not easily removed. Oxygen and nitrogen are introduced during normal gas handling or by mistakes such as not evacuating all the air from the equipment before filling with SF_6. Fortunately, the purity of the SF_6 needs only be above 98% as established by international technical committees [12], so a simple field check of purity using commercially available percentage SF_6 meters will qualify the used SF_6 for reuse. For severe cases of contamination, the SF_6 manufacturers will take back the contaminated SF_6 and by putting it back into the production process in effect turn it back into "new" SF_6. Although not yet necessary, an end of life scenario for the eventual retirement of SF_6 is to incinerate the SF_6 with materials that will enable it to become part of environmentally acceptable gypsum.

The U.S. Environmental Protection Agency has a voluntary SF_6 emissions reduction program for the electric utility industry that keeps track of emissions rates, provides information on techniques to reduce emissions, and rewards utilities that have effective SF_6 emission reduction programs by high level recognition of progress. Other counties have addressed the concern similarly or even considered

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Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart A—General Provision

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

GLOBAL WARMING POTENTIALS

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	21
Nitrous oxide	10024-97-2	N_2O	310
HFC-23	75-46-7	CHF_3	11,700
HFC-32	75-10-5	CH_2F_2	650
HFC-41	593-53-3	CH_3F	150
HFC-125	354-33-6	C_2HF_5	2,800
HFC-134	359-35-3	$C_2H_2F_4$	1,000
HFC-134a	811-97-2	CH_2FCF_3	1,300
HFC-143	430-66-0	$C_2H_3F_3$	300
HFC-143a	420-46-2	$C_2H_3F_3$	3,800
HFC-152	624-72-6	CH_2FCH_2F	53
HFC-152a	75-37-6	CH_3CHF_2	140
HFC-161	353-36-6	CH_3CH_2F	12
HFC-227ea	431-89-0	C_3HF_7	2,900
HFC-236cb	677-56-5	$CH_2FCF_2CF_3$	1,340
HFC-236ea	431-63-0	CHF_2CHFCF_3	1,370
HFC-236fa	690-39-1	$C_3H_2F_6$	6,300
HFC-245ca	679-86-7	$C_3H_3F_5$	560
HFC-245fa	460-73-1	$CHF_2CH_2CF_3$	1,030
HFC-365mfc	406-58-6	$CH_3CF_2CH_2CF_3$	794
HFC-43-10mee	138495-42-8	$CF_3CFHCFHCF_2CF_3$	1,300
Sulfur hexafluoride	2551-62-4	SF_6	23,900
Trifluoromethyl sulphur pentafluoride	373-80-8	SF_5CF_3	17,700
Nitrogen trifluoride	7783-54-2	NF_3	17,200
PFC-14 (Perfluoromethane)	75-73-0	CF_4	6,500