Appendix A

Potential Emissions Calculations

Potential Emissions Summary
Combustion Turbine - Normal Operation
Pioneer Valley Energy Center
Westfield, Massachusetts

Mitsubishi M501 G Combustion Turbine - Air Cooled		
Parameter	Natural Gas (100%, 59F)	ULSD (100%, 10F)
Annual Operation	6,775 hr/yr	1,440 hr/yr
Power Output:	387.0 MW	296.1 MW
Heat Rate:	5,846.0 Btu/kWh	6,809.0 Btu/kWh
Heat Input Rate:	2,263.0 MMBtu/hr	2,016.1 MMBtu/hr

		Natural Gas						ULSD					Total
Pollutant	Emission Factor Source	Stack Conc. ppmvd15%	Emission Rate lb/MMBtu	Emission Rate lb/hr	Emission Rate lb/MW-hr	Emission Rate lb/yr	Emission Rate ton/yr	Stack Conc. ppmvd15%	Emission Rate lb/MMBtu	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr	Emission Rate ton/yr
NOx	MHI	2.0	0.0080	18.0	0.047	121,950	61.0	5.0	0.021	43.0	61,920	31.0	91.9
CO	MHI	2.0	0.0049	11.0	0.028	74,525	37.3	6.0	0.016	31.5	45,360	22.7	59.9
SO2	MHI		0.0019	4.2	0.011	28,455	14.2		0.0017	3.4	4,896	2.4	16.7
H2SO4	MHI		0.0019	4.3	0.0111	29,133	14.6		0.0018	3.6	5,184	2.6	17.2
PM10	MHI		0.0039	8.8	0.023	59,620	29.8		0.013	26.8	38,592	19.3	49.1
PM2.5	MHI		0.0039	8.8	0.023	59,620	29.8		0.013	26.8	38,592	19.3	49.1
CO2	MHI		129.8	293,700	759	1,989,817,500	994,909		175.7	354,300	510,192,000	255,096	1,250,005
NH3	MHI	2.0	0.0030	6.7	0.017	45,393	22.7	2.0	0.0032	6.4	9,216	4.6	27.3
VOC	MHI	1.0	0.0014	3.2	0.0083	21,680	10.8	6.0	0.0089	18.0	25,920	13.0	23.8
								ppb in fuel					
Arsenic (HAP)	**			0.0E+00	0.0E+00	0	0.00	0.9	4.5E-08	9.1E-05	0	0.00	0.00
Beryllium (HAP)	AP-42			0.0E+00	0.0E+00	0	0.00		<3.1E-07	6.2E-04	1	0.00	0.00
Cadmium (HAP)	**			0.0E+00	0.0E+00	0	0.00	0.1	5.0E-09	1.0E-05	0	0.00	0.00
Chromium (HAP)	**			0.0E+00	0.0E+00	0	0.00	242.4	1.2E-05	2.4E-02	35	0.02	0.02
Lead (HAP)	**			0.0E+00	0.0E+00	0	0.00	15	7.5E-07	1.5E-03	2	0.00	0.00
Manganese (HAP)	**			0.0E+00	0.0E+00	0	0.00	5.5	2.8E-07	5.6E-04	1	0.00	0.00
Mercury (HAP)	**			0.0E+00	0.0E+00	0	0.00	0.2	1.0E-08	2.0E-05	0	0.00	0.00
Nickel (HAP)	**			0.0E+00	0.0E+00	0	0.00	28.9	1.4E-06	2.9E-03	4	0.00	0.00
Selenium (HAP)	**			0.0E+00	0.0E+00	0	0.00	5	2.5E-07	5.0E-04	1	0.00	0.00
1,3-Butadiene (HAP)	AP-42		<4.3E-07	9.7E-04	2.51E-06	7	0.00		<1.6E-05	3.2E-02	46	0.02	0.03
Acetaldehyde (HAP)	AP-42		4.0E-05	9.1E-02	2.34E-04	613	0.31			0.0E+00	0	0.00	0.31
Acrolein (HAP)	AP-42		6.4E-06	1.4E-02	3.74E-05	98	0.05			0.0E+00	0	0.00	0.05
Benzene (HAP)	AP-42		1.2E-05	2.7E-02	7.02E-05	184	0.09		5.5E-05	1.1E-01	160	0.08	0.17
Ethylbenzene (HAP)	AP-42		3.2E-05	7.2E-02	1.87E-04	491	0.25			0.0E+00	0	0.00	0.25
Formaldehyde (HAP)	MHI		2.7E-04	6.0E-01	1.55E-03	4,065	2.03		3.0E-04	6.0E-01	864	0.43	2.46
Naphthalene (HAP)	AP-42		1.3E-06	2.9E-03	7.60E-06	20	0.01		3.5E-05	7.1E-02	102	0.05	0.06
PAH	AP-42		2.2E-06	5.0E-03	1.29E-05	34	0.02		4.0E-05	8.1E-02	116	0.06	0.07
Propylene Oxide (HAP)	AP-42		<2.9E-05	6.6E-02	1.70E-04	445	0.22			0.0E+00	0	0.00	0.22
Toluene (HAP)	AP-42		1.3E-04	2.9E-01	7.60E-04	1,993	1.00			0.0E+00	0	0.00	1.00
Xylenes (HAP)	AP-42		6.4E-05	1.4E-01	3.74E-04	981	0.49			0.0E+00	0	0.00	0.49
Total HAPS			5.8E-04	1.3E+00	3.39E-03	8,897	4.45		4.2E-04	8.4E-01	1,216	0.61	5.06

** Fuel oil metals emission factors are dervied from the "Survey of Ultra-Trace Metals in Gas Turbine Fuels", 2004.

Potential Emissions Summary
Combustion Turbine - Startup & Shutdown
Pioneer Valley Energy Center
Westfield, Massachusetts

Mitsubishi M501 G Combustion Turbine - Air Cooled		
Parameter	Natural Gas	Notes
Annual Operation	545 hr/yr	
Output	249.2 MW	60% Load @ 59F
Heat Rate	6,175.0 Btu/kWh	60% Load @ 59F
Heat Input	1,539.0 MMBtu/hr	60% Load @ 59F

Startup/Shutdown Emissions												
Projected Startups & Shutdowns				NOx Emissions			CO Emissions			NH3 Emissions		
	Events/Yr	Hrs/Event	Hrs/Yr	lb/hr	lb/event	ton/yr	lb/hr	lb/event	ton/yr	lb/hr	lb/event	ton/yr
Hot Starts	0	1.00	0	62	62	0.00	2,068	2,068	0.00	6.0	6	0.00
Warm Starts	141	2.00	282	48	96	6.77	1,772	3,544	249.85	5.0	10	0.71
Cold Starts	35	5.00	175	44	221	3.87	1,756	8,781	153.67	4.4	22	0.39
Shutdowns	176	0.50	88	44	22	1.94	1,906	953	83.86	8.0	4	0.35
Total			545			12.57			487.38			1.44

Pollutant	Emission Factor Source	Natural Gas Stack Conc. ppmvd15%	Emission Rate lb/MMBtu	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
SO2	MHI		0.0019	2.9	1,581	0.8
H2SO4	MHI		0.0019	3.0	1,635	0.8
PM10	MHI		0.0040	6.1	3,325	1.7
PM2.5	MHI		0.0040	6.1	3,325	1.7
CO2	MHI		129.6	199,400	108,673,000	54,337
VOC	MHI		0.0014	2.2	1,199	0.6
1,3-Butadiene (HAP)	AP-42		<4.3E-07	6.6E-04	0	0.00
Acetaldehyde (HAP)	AP-42		4.0E-05	6.2E-02	34	0.02
Acrolein (HAP)	AP-42		6.4E-06	9.8E-03	5	0.00
Benzene (HAP)	AP-42		1.2E-05	1.8E-02	10	0.01
Ethylbenzene (HAP)	AP-42		3.2E-05	4.9E-02	27	0.01
Formaldehyde (HAP)	MHI		2.6E-04	4.0E-01	218	0.11
Naphthalene (HAP)	AP-42		1.3E-06	2.0E-03	1	0.00
PAH	AP-42		2.2E-06	3.4E-03	2	0.00
Propylene Oxide (HAP)	AP-42		<2.9E-05	4.5E-02	24	0.01
Toluene (HAP)	AP-42		1.3E-04	2.0E-01	109	0.05
Xylenes (HAP)	AP-42		6.4E-05	9.8E-02	54	0.03
Total HAPS			5.8E-04	8.8E-01	482	0.24

Potential Emissions Summary
Auxiliary Boiler
Pioneer Valley Energy Center
Westfield, Massachusetts

Auxiliary Boiler	
Parameter	Natural Gas
Annual Operation	1,100 hr/yr
Heat Input Rate	21.0 MMBtu/hr
Fuel Firing Rate	0.021 MMscf/hr

Pollutant	Emission Factor Source	Natural Gas					
		Emission Factor Units	Emission Factor	MA ERP Limit	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
NOx	PFI	lb/MMBtu	0.029	0.035	0.61	670	0.3
CO	PFI	lb/MMBtu	0.037	0.080	0.78	855	0.4
SO2	PFI	lb/MMBtu	0.0005		0.011	12	0.0
PM10	PFI	lb/MMBtu	0.0048	0.010	0.10	111	0.1
PM2.5	PFI	lb/MMBtu	0.0048		0.10	111	0.1
CO2	AP-42	lb/MMscf	120,000.0		2,520	2,772,000	1,386.0
VOC	PFI	lb/MMBtu	0.003	0.030	0.063	69	0.0
Arsenic (HAP)	AP-42	lb/MMscf	2.0E-04		4.2E-06	0	0.00
Barium	AP-42	lb/MMscf	4.4E-03		9.2E-05	0	0.00
Beryllium (HAP)	AP-42	lb/MMscf	1.2E-05		2.5E-07	0	0.00
Cadmium (HAP)	AP-42	lb/MMscf	1.1E-03		2.3E-05	0	0.00
Chromium (HAP)	AP-42	lb/MMscf	1.4E-03		2.9E-05	0	0.00
Cobalt (HAP)	AP-42	lb/MMscf	8.4E-05		1.8E-06	0	0.00
Lead (HAP)	AP-42	lb/MMscf	5.0E-04		1.1E-05	0	0.00
Manganese (HAP)	AP-42	lb/MMscf	3.8E-04		8.0E-06	0	0.00
Mercury (HAP)	AP-42	lb/MMscf	2.6E-04		5.5E-06	0	0.00
Molybdenum	AP-42	lb/MMscf	1.1E-03		2.3E-05	0	0.00
Nickel (HAP)	AP-42	lb/MMscf	2.1E-03		4.4E-05	0	0.00
Selenium (HAP)	AP-42	lb/MMscf	2.4E-05		5.0E-07	0	0.00
Vanadium	AP-42	lb/MMscf	2.3E-03		4.8E-05	0	0.00
Zinc	AP-42	lb/MMscf	2.9E-02		6.1E-04	1	0.00
2-Methylnaphthalene	AP-42	lb/MMscf	2.4E-05		5.0E-07	0	0.00
3-Methylchloroanthrene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
7,12-Dimethylbenz(a)anthracer	AP-42	lb/MMscf	1.6E-05		3.4E-07	0	0.00
Acenaphthene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Acenaphthylene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Anthracene	AP-42	lb/MMscf	2.4E-06		5.0E-08	0	0.00
Benz(a)anthracene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Benzene (HAP)	AP-42	lb/MMscf	2.1E-03		4.4E-05	0	0.00
Benzo(a)pyrene	AP-42	lb/MMscf	1.2E-06		2.5E-08	0	0.00
Benzo(b)fluoranthene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Benzo(g,h,i)perylene	AP-42	lb/MMscf	1.2E-06		2.5E-08	0	0.00
Benzo(k)fluoranthene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Butane	AP-42	lb/MMscf	2.1E+00		4.4E-02	49	0.02
Chrysene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Dibenzo(a,h)anthracene	AP-42	lb/MMscf	1.2E-06		2.5E-08	0	0.00
Dichlorobenzene	AP-42	lb/MMscf	1.2E-03		2.5E-05	0	0.00
Ethane	AP-42	lb/MMscf	3.1E+00		6.5E-02	72	0.04
Fluoranthene	AP-42	lb/MMscf	3.0E-06		6.3E-08	0	0.00
Fluorene	AP-42	lb/MMscf	2.8E-06		5.9E-08	0	0.00
Formaldehyde (HAP)	AP-42	lb/MMscf	7.5E-02		1.6E-03	2	0.00
Hexane (HAP)	AP-42	lb/MMscf	1.8E+00		3.8E-02	42	0.02
Indeno(1,2,3-cd)pyrene	AP-42	lb/MMscf	1.8E-06		3.8E-08	0	0.00
Naphthalene (HAP)	AP-42	lb/MMscf	6.1E-04		1.3E-05	0	0.00
Pentane	AP-42	lb/MMscf	2.6E+00		5.5E-02	60	0.03
Phenanthrene	AP-42	lb/MMscf	1.7E-05		3.6E-07	0	0.00
Propane	AP-42	lb/MMscf	1.6E+00		3.4E-02	37	0.02
Pyrene	AP-42	lb/MMscf	5.0E-06		1.1E-07	0	0.00
Toluene (HAP)	AP-42	lb/MMscf	3.4E-03		7.1E-05	0	0.00
Total HAPS			1.9E+00		4.0E-02	44	0.02

Potential Emissions Summary
Emergency Generator
Pioneer Valley Energy Center
Westfield, Massachusetts

Emergency Generator	
Parameter	Diesel Fuel
Annual Operation	300 hr/yr
Fuel Usage Rate:	110.2 gal/hr
Heat Input Rate	15.43 MMBtu/hr
Power Output	2,174.0 hp

Pollutant	Emission Factor Source	Diesel Fuel				
		Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
NOx	PB	lb/hr		37.47	11,241	5.6
CO	PB	lb/hr		12.20	3,660	1.8
SO2	PB	lb/hr		3.13	939	0.5
PM10	PB	lb/hr		0.91	273	0.1
PM2.5	PB	lb/hr		0.91	273	0.1
CO2	AP-42	lb/MMBtu	165.0	2,545.95	763,785	381.9
VOC	PB	lb/hr		1.67	501	0.3
Benzene (HAP)	AP-42	lb/MMBtu	7.76E-04	1.20E-02	4	0.00
Toluene (HAP)	AP-42	lb/MMBtu	2.81E-04	4.34E-03	1	0.00
Xylenes (HAP)	AP-42	lb/MMBtu	1.93E-04	2.98E-03	1	0.00
Propylene	AP-42	lb/MMBtu	2.79E-03	4.30E-02	13	0.01
Formaldehyde (HAP)	AP-42	lb/MMBtu	7.89E-05	1.22E-03	0	0.00
Acetaldehyde (HAP)	AP-42	lb/MMBtu	2.52E-05	3.89E-04	0	0.00
Acrolein (HAP)	AP-42	lb/MMBtu	7.88E-06	1.22E-04	0	0.00
Naphthalene (HAP)	AP-42	lb/MMBtu	1.30E-04	2.01E-03	1	0.00
Acenaphthylene	AP-42	lb/MMBtu	9.23E-06	1.42E-04	0	0.00
Acenaphthene	AP-42	lb/MMBtu	4.68E-06	7.22E-05	0	0.00
Fluorene	AP-42	lb/MMBtu	1.28E-05	1.98E-04	0	0.00
Phenanthrene	AP-42	lb/MMBtu	4.08E-05	6.30E-04	0	0.00
Anthracene	AP-42	lb/MMBtu	1.23E-06	1.90E-05	0	0.00
Fluoranthene	AP-42	lb/MMBtu	4.03E-06	6.22E-05	0	0.00
Pyrene	AP-42	lb/MMBtu	3.71E-06	5.72E-05	0	0.00
Benz(a)anthracene	AP-42	lb/MMBtu	6.22E-07	9.60E-06	0	0.00
Chrysene	AP-42	lb/MMBtu	1.53E-06	2.36E-05	0	0.00
Benzo(b)fluoranthene	AP-42	lb/MMBtu	1.11E-06	1.71E-05	0	0.00
Benzo(k)fluoranthene	AP-42	lb/MMBtu	2.18E-07	3.36E-06	0	0.00
Benzo(a)pyrene	AP-42	lb/MMBtu	2.57E-07	3.97E-06	0	0.00
Indeno(1,2,3-cd)pyrene	AP-42	lb/MMBtu	4.14E-07	6.39E-06	0	0.00
Dibenzo(a,h)anthracene	AP-42	lb/MMBtu	3.46E-07	5.34E-06	0	0.00
Benzo(g,h,l)perylene	AP-42	lb/MMBtu	5.56E-07	8.58E-06	0	0.00
Total PAH	AP-42	lb/MMBtu	2.12E-04	3.27E-03	1	0.00
Total HAPS			1.49E-03	2.30E-02	7	0.00

Potential Emissions Summary
Fire Pump
Pioneer Valley Energy Center
Westfield, Massachusetts

Fire Pump	
Parameter	Diesel Fuel
Annual Operation	300 hr/yr
Fuel Usage Rate:	13.5 gal/hr
Heat Input Rate	1.89 MMBtu/hr
Power Output	270.0 hp

		Diesel Fuel				
Pollutant	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
NOx	PB	lb/hr		3.24	972	0.5
CO	PB	lb/hr		1.85	555	0.3
SO2	PB	lb/hr		0.37	111	0.1
PM10	PB	lb/hr		0.15	45	0.0
PM2.5	PB	lb/hr		0.15	45	0.0
CO2	AP-42	lb/MMBtu	164.0	309.96	92,988	46.5
VOC	PB	lb/hr		0.49	147	0.1
Benzene (HAP)	AP-42	lb/MMBtu	7.76E-04	1.47E-03	0	0.00
Toluene (HAP)	AP-42	lb/MMBtu	2.81E-04	5.31E-04	0	0.00
Xylenes (HAP)	AP-42	lb/MMBtu	1.93E-04	3.65E-04	0	0.00
Propylene	AP-42	lb/MMBtu	2.79E-03	5.27E-03	2	0.00
Formaldehyde (HAP)	AP-42	lb/MMBtu	7.89E-05	1.49E-04	0	0.00
Acetaldehyde (HAP)	AP-42	lb/MMBtu	2.52E-05	4.76E-05	0	0.00
Acrolein (HAP)	AP-42	lb/MMBtu	7.88E-06	1.49E-05	0	0.00
Naphthalene (HAP)	AP-42	lb/MMBtu	1.30E-04	2.46E-04	0	0.00
Acenaphthylene	AP-42	lb/MMBtu	9.23E-06	1.74E-05	0	0.00
Acenaphthene	AP-42	lb/MMBtu	4.68E-06	8.85E-06	0	0.00
Fluorene	AP-42	lb/MMBtu	1.28E-05	2.42E-05	0	0.00
Phenanthrene	AP-42	lb/MMBtu	4.08E-05	7.71E-05	0	0.00
Anthracene	AP-42	lb/MMBtu	1.23E-06	2.32E-06	0	0.00
Fluoranthene	AP-42	lb/MMBtu	4.03E-06	7.62E-06	0	0.00
Pyrene	AP-42	lb/MMBtu	3.71E-06	7.01E-06	0	0.00
Benz(a)anthracene	AP-42	lb/MMBtu	6.22E-07	1.18E-06	0	0.00
Chrysene	AP-42	lb/MMBtu	1.53E-06	2.89E-06	0	0.00
Benzo(b)fluoranthene	AP-42	lb/MMBtu	1.11E-06	2.10E-06	0	0.00
Benzo(k)fluoranthene	AP-42	lb/MMBtu	2.18E-07	4.12E-07	0	0.00
Benzo(a)pyrene	AP-42	lb/MMBtu	2.57E-07	4.86E-07	0	0.00
Indeno(1,2,3-cd)pyrene	AP-42	lb/MMBtu	4.14E-07	7.82E-07	0	0.00
Dibenzo(a,h)anthracene	AP-42	lb/MMBtu	3.46E-07	6.54E-07	0	0.00
Benzo(g,h,l)perylene	AP-42	lb/MMBtu	5.56E-07	1.05E-06	0	0.00
Total PAH	AP-42	lb/MMBtu	2.12E-04	4.01E-04	0	0.00
Total HAPS			1.49E-03	2.82E-03	1	0.00

Potential Emissions Summary
Cooling Tower
Pioneer Valley Energy Center
Westfield, Massachusetts

Cooling Tower Specification	Data Source	Data Result
Hours of Operation:		8,760 hours
Circulating Water Flow Rate:	SPX	81,935 gpm
Drift Eliminator Efficiency:	SPX	0.0005 %
Total Liquid Drift:	calc.	0.41 gpm
Density of Water:	constant	8.34 lb/gal
Total Liquid Drift:	calc.	205.0 lb/hr
Source Water TDS:	Holyoke Water Works	<5 ppm
Cycles of Concentration:		10 cycles
Circulating Water TDS:	calc.	50 ppm
PM_{10} Emission Rate:	calc.	0.010 lb/hr
PM_{10} Emission Rate:	calc.	0.045 ton/yr

Calculations

Total Liquid Drift (gpm) = (Circulating Water Flow Rate, gpm) x (Drift Eliminator Efficiency, %)
Total Liquid Drift (lb/hr) = (Total Liquid Drift, gpm) x (Density of Water, lb/gal)
Circulating Water TDS (ppm) = (Source Water TDS, ppm) x (Cycles of Concentration)
PM_{10} Emission Rate (lb/hr) = (Total Liquid Drift, lb/hr) x ((Circulating Water TDS, ppm) / 10^6)
PM_{10} Emission Rate (ton/yr) = (PM_{10} Emission Rate, lb/hr) x (Hours of Operation) x (1 ton / 2000 lbs)

Appendix B

RBLC BACT Determinations

RBLC Summary

Combined Cycle Turbines, >200 MW, Natural Gas Fuel, Permitted Since 2000

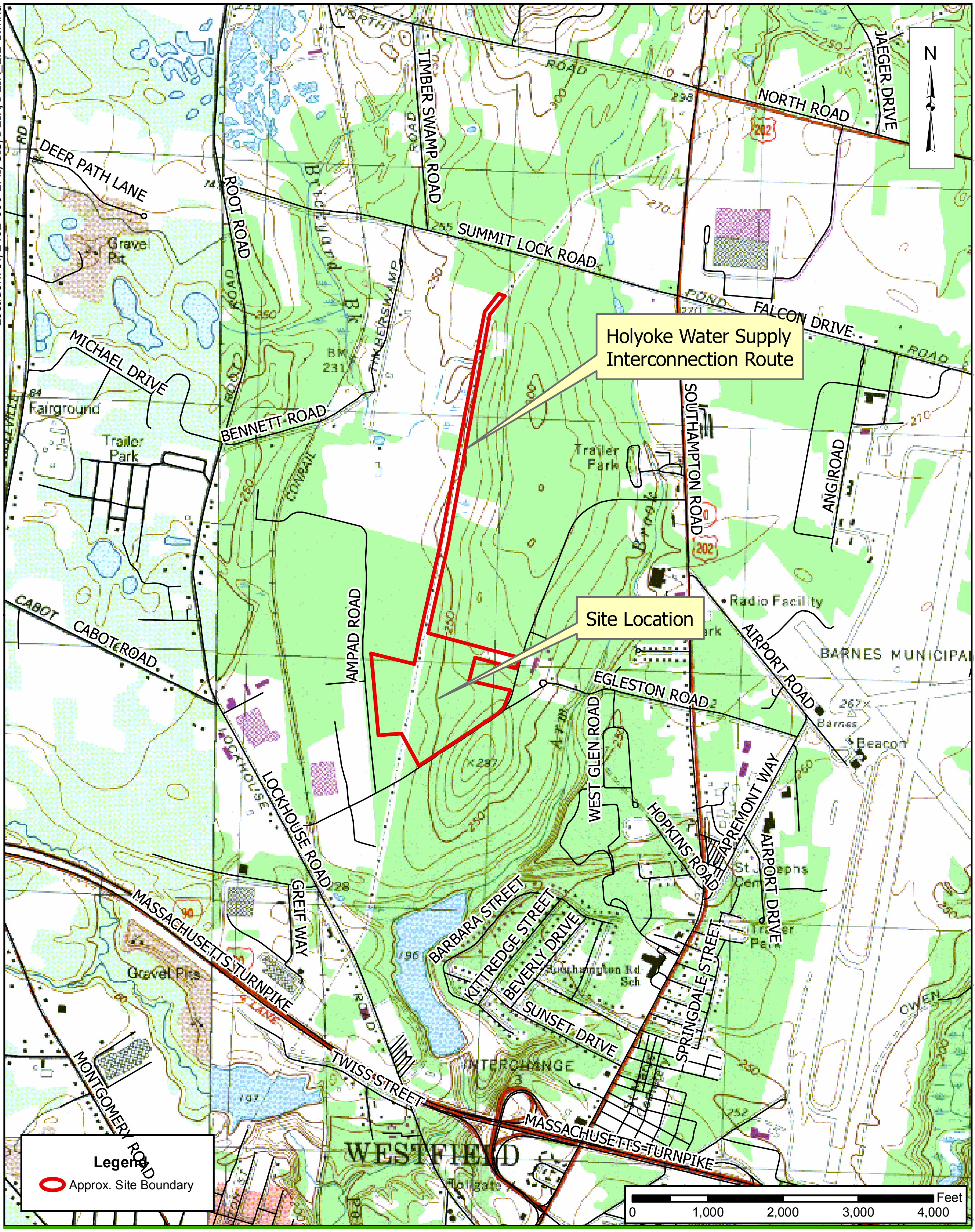
RBLC ID	Permit Date	Facility	Corporate/Company Name	State	MW	NOx		CO		VOC		PM10		SO2		H2SO4		NH3		Controls	CTG
CT-0151	05/12/08	Kleen Energy Systems, LLC	Kleen Energy Systems, LLC	CT	300	2.0000	ppm15	0.9000	ppm15	5.0000	ppm15	11.0000	lb/hr	4.9000	lb/hr			2.0000	ppm15	DLNC / SCR / OC	Siemens SGT6-5000F
NY-0095	05/10/06	Caithness Bellport Energy Center	Caithness Bellport, LLC	NY	346	2.0000	ppm15	2.0000	ppm15			0.0055	lb/MM	0.0011	lb/MM	0.0004	lb/MM			SCR / OC	
CO-0056	05/02/06	Rocky Mountain Energy Center, LLC	Calpine Corp.	CO	300	3.0000	ppm15	3.0000	ppm15	0.0029	lb/MM	0.0074	lb/MM							DLNC / SCR	
NV-0035	08/16/05	Tracy Substation Expansion	Sierra Pacific Power Company	NV	306	2.0000	ppm15	3.5000	ppm15	4.0000	ppm15	0.0110	lb/MM			1.0000	lb/hr			SCR / OC	
MN-0060	08/12/05	High Bridge Generating Plant	Northern States Power Company	MN	330			10.0000	ppm15	2.0000	ppm15										
MS-0073	11/23/04	Reliant Energy Choctaw County, LLC	Reliant Energy Choctaw County, LLC	MS	230	3.5000	ppm15	18.3600	ppm15	3.6400	ppm15	20.5900	lb/hr	1.3800	lb/hr					SCR	
NE-0023	06/22/04	Beatrice Power Station	Nebraska Public Power District	NE	250	3.5000	ppm15	18.4000	ppm15			10.8000	lb/hr							DLNC / SCR	
OR-0039	12/30/03	Cob Energy Facility, LLC	People Energy Resources	OR	290	2.5000	ppm15	2.0000	ppm15	7.1000	ppm15	14.0000	lb/hr	0.8000	lb/hr			5.0000	ppm15	DLNC / SCR / OC	GE 7FA
NV-0038	12/29/03	Ivanpah Energy Center, L.P.	Ivanpah Energy Center, L.P.	NV	250	2.0000	ppm15	4.0000	ppm15	2.3000	ppm15	11.2500	lb/hr	1.5500	lb/hr			10.0000	ppm15	SCR / OC	W 501 FD
AZ-0043	11/12/03	Duke Energy Arlington Valley	Duke Energy Arlington Valley	AZ	325	2.0000	ppm15	2.0000	ppm15	1.0000	ppm15	18.0000	lb/hr							CATOX / SCR	
AZ-0049	09/04/03	La Paz Generating Facility	Allegheny Energy Supply LLC	AZ	1080	2.0000	ppm15	3.0000	ppm15	2.5000	ppm15	0.0148	lb/MM	0.0021	lb/MM					DLNC / SCR / OC	SW501G
WA-0315	04/17/03	Sumas Energy 2	Sumas Energy 2, Inc.	WA	330	2.0000	ppm15	2.0000	ppm15	17.5000	lb/hr	8.0830	lb/hr	1.0000	lb/hr	1.6250	lb/hr	5.0000	ppm15	DLNC / SCR / OC	
OR-0040	03/12/03	Klamath Generation, LLC	Klamath Generation, LLC	OR	240	2.5000	ppm15	5.0000	ppm15	7.2000	ppm15	0.0042	lb/MM	0.8000	lb/hr			10.0000	ppm15	DLNC / SCR / OC	
MI-0357	02/04/03	Kalkaska Generating, Inc.	Kalkaska Generating LLC	MI	303	3.0000	ppm15	5.0000	ppm15	3.5000	ppm15	38.0000	lb/hr	5.2000	lb/hr	4.5000	lb/hr	10.0000	ppm15	DLNC / SCR / OC	
WA-0291	01/03/03	Wallula Power Plant	Wallula Generation, LLC	WA	325	2.5000	ppm15	2.0000	ppm15	5.0000	ppm15	20.8000	lb/hr	4.5000	lb/hr	1.9100	lb/hr	5.0000	ppm15	SCR / OC	
VA-0255	11/18/02	Possum Point	Virginia Power	VA	270	3.5000	ppm15	19.3000	ppm15	2.3000	ppm15	22.2000	lb/hr	2.0800	lb/hr					SCR	GE 7FA
WA-0299	09/06/02	Sumas Energy 2	Sumas Energy 2, Inc.	WA	335	0.0080	lb/MM	0.0110	lb/MM	0.0085	lb/MM	0.0115	lb/MM	0.0038	lb/MM	0.0008	lb/MM	5.0000	ppm15	SCR / OC	
CO-0052	08/11/02	Rocky Mountain Energy Center, LLC	Rocky Mountain Energy Center, LLC	CO	315	3.0000	ppm15	9.0000	ppm15	0.0026	lb/MM	0.0065	lb/MM							DLNC / SCR	
TX-0437	07/05/02	Hartburg Power, LP	Hartburg Power, LP	TX	277	5.0000	ppm15	15.0000	ppm15	4.0000	ppm15									DLNC / SCR	
OH-0264	05/23/02	Norton Energy Storage, LLC	Norton Energy	OH	300	3.5000	ppm15	11.0000	ppm15	4.0000	ppm15	13.0000	lb/hr	2.5500	lb/hr	0.1980	lb/hr	20.0000	lb/hr	DLNC / SCR	
IA-0058	04/10/02	Greater Des Moines Energy Center	Midamerican Energy	IA	350	0.0110	lb/MM	0.0120	lb/MM			0.0108	lb/MM							DLNC / SCR / OC	
PA-0226	04/09/02	Limerick Power Station	Limerick Partners, LLC	PA	275	2.0000	ppm15	10.0000	ppm15	2.4000	ppm15	0.0140	lb/MM							DLNC	
TX-0350	01/31/02	Ennis Tractebel Power	Ennis-Tractebel II LP	TX	230	9.0000	ppm15	20.0000	ppm15	7.0900	ppm15	25.6200	lb/hr	19.3300	lb/hr	2.3700	lb/hr	37.6600	lb/hr		
PA-0223	01/30/02	Duke Energy Fayette, LLC	Duke Energy Fayette, LLC	PA	280	2.5000	ppm15	5.0000	ppm15	5.3000	ppm15	34.8000	lb/hr	1.6000	lb/hr					DLNC / SCR / OC	
OR-0035	01/16/02	Port Westward Plant	Portland General Electric Company	OR	325	2.5000	ppm15	4.9000	ppm15	4.9000	ppm15	0.1400	lb/MM	0.8000	lb/hr			10.0000	ppm15	DLNC / SCR / OC	
VA-0256	01/11/02	Tenaska Fluvanna	Tenaska Virginia Partners LP	VA	300	3.0000	ppm15	21.0000	ppm15	15.5000	lb/hr	16.2000	lb/hr	4.0000	lb/hr	4.8000	lb/hr			SCR	
OH-0257	12/27/01	Jackson County Power, LLC	Jackson County Power, LLC	OH	305	3.5000	ppm15	9.0000	ppm15	8.5000	ppm15	30.2000	lb/hr	15.3000	lb/hr	1.1700	lb/hr	34.0000	lb/hr	DLNC / SCR	
WV-0014	12/18/01	Panda Culloden Generating	Panda Culloden Power LP	WV	300	3.5000	ppm15	8.2000	ppm15	1.4000	ppm15	18.0000	lb/hr	5.4000	lb/hr	0.6200	lb/hr			DLNC / SCR	GE 7FA
IN-0095	12/07/01	Allegheny Energy Supply Co.	Acadia Bay Energy	IN	315	2.5000	ppm15	6.0000	ppm15	0.0034	lb/MM	0.0120	lb/MM	0.0034	lb/MM			10.0000	ppm15	DLNC / SCR	SW 501FD
AR-0047	11/09/01	Hot Springs Power Project	Hot Springs Power Project	AR	700	3.5000	ppm15	12.0000	ppm15	4.0000	ppm15	0.0130	lb/MM							CATOX / DLNC / SCR	
GA-0093	10/28/01	Augusta Energy Center	August Energy Center	GA	250	3.0000	ppm15	2.0000	ppm15	2.0000	ppm15									SCR / OC	
PA-0192	10/20/01	Lower Mount Bethel Energy, LLC	Lower Mount Bethel Energy, LLC	PA	370	3.5000	ppm15	6.0000	ppm15	3.0000	ppm15	0.0135	lb/MM	0.0027	lb/MM	0.0008	lb/MM			DLNC / SCR / OC	
ID-0012	10/19/01	Garnet Energy Middleton	Garnet Energy LLC	ID	268	2.5000	ppm15	2.0000	ppm15	10.2000	ppm15	0.0150	lb/MM	6.6000	lb/hr			10.0000	ppm15	DLNC / SCR / OC	
FL-0233	09/21/01	OUC Stanton Energy Center	Orlando Utilities Commission	FL	320	3.5000	ppm15	17.0000	ppm15											SCR	
FL-0226	09/11/01	El Paso Manatee Energy Center	El Paso Merchant Energy Company	FL	250	2.5000	ppm15	7.4000	ppm15	1.4000	ppm15	20.0000	lb/hr							DLNC / SCR	
FL-0227	09/07/01	El Paso Belle Glade Energy Center	El Paso Merchant Energy Company	FL	250	2.5000	ppm15	7.4000	ppm15	1.4000	ppm15	20.0000	lb/hr							DLNC / SCR	
WA-0288	09/04/01	Longview Energy Development	Longview Energy Development	WA	290	2.5000	ppm15	2.0000	ppm15	5.7000	ppm15	17.0000	lb/hr	1.4000	lb/hr			10.0000	ppm15	SCR / OC	
NJ-0058	08/24/01	PSEG Linden Generating Station	PSEG Fosill LLC	NJ	600	2.0000	ppm15	2.0000	ppm15	2.1000	ppm15	21.0000	lb/hr	2.0000	lb/hr					DLNC / SCR / OC	GE 7FA
OK-0045	08/15/01	Redbud Power Plant	Redbud Energy LP	OK	275	15.0000	ppm15	15.0000	ppm15	7.0000	ppm15	0.0100	lb/MM	0.0050	lb/MM					DLNC	
PA-0196	08/07/01	SWEC-Falls Township	SWEC-Falls Township	PA	544	3.0000	ppm15	3.0000	ppm15	0.0020	lb/MM	0.0140	lb/MM	0.0020	lb/MM					DLNC / SCR / OC	
MI-0303	07/26/01	Midland Cogeneration	Midland Cogeneration Venture	MI	262	3.5000	ppm15	15.0000	ppm15	4.2000	ppm15	0.0200	lb/MM					10.0000	ppm15	DLNC / SCR	GE 7FA
PA-0197	06/15/01	Reliant Energy Hunterstown, LLC	Reliant Energy Hunterstown, LLC	PA	300	3.5000	ppm15	14.0000	ppm15	3.5000	ppm15	0.0106	lb/MM	0.0015	lb/MM	0.0009	lb/MM			DLNC / SCR / OC	
IN-0085	06/07/01	PSEG Lawrenceburg Energy	PSEG Lawrenceburg Energy	IN	282	3.0000	ppm15	6.0000	ppm15	3.0000	ppm15	21.0000	lb/hr	11.0000	lb/hr					SCR	
FL-0219	05/03/01	CPV Atlantic Power	CPV Atlantic, LTD	FL	245	3.5000	ppm15	9.0000	ppm15	1.4000	ppm15	11.0000	lb/hr	0.0065	lb/MM	0.0065	lb/MM			DLNC / SCR	GE 7FA
WA-0302	02/23/01	Goldendale Energy Project	Goldendale Energy, Inc.	WA	249	2.0000	ppm15	2.0000	ppm15	2.8000	ppm15	19.0000	lb/hr	1.0000	lb/hr	0.2070	lb/hr	12.2000	lb/hr	DLNC / SCR / OC	
AZ-0034	02/15/01	Harquahala Generating Project	Harquahala Generating Co.	AZ	240	2.5000	ppm15	10.0000	ppm15	2.8000	ppm15	24.0000	lb/hr	5.8000	lb/hr					SCR / OC	SW501G
CO-0049	01/17/01	Kiowa Creek	North American Power Gp	CO	250	4.0000	ppm15	25.0000	ppm15	0.0028	lb/MM	0.0136	lb/MM							DLNC / SCR	
MN-0048	01/12/01	Black Dog Generating Plant	Northern States Power Company	MN	290			18.0000	ppm15	0.0073	lb/MM									DLNC / SCR	
AZ-0035	12/14/00	Duke Energy Arlington Valley	Duke Energy Arlington Valley	AZ	255	2.5000	ppm15	20.0000	ppm15	1.4000	ppm15	27.0000	lb/hr							SCR	
PA-0184	10/10/00	Calpine Berks Ontelaunee	Calpine Construction Finance Co.	PA	272	2.5000	ppm15	10.0000	ppm15	1.8000	ppm15					0.0003	lb/MM			SCR / OC	
AR-0041	08/08/00	TPS - Dell, LLC	TPS - Dell, LLC	AR	320	3.5000	ppm15	7.0000	ppm15	0.0049	lb/MM	0.0210	lb/MM	0.0020	lb/MM					DLNC / SCR	
TX-0372	07/28/00	West Texas Energy Facility	West Texas Energy LP	TX	250	5.0000	ppm15	5.0000	ppm15	2.1000	ppm15	15.9000	lb/hr	3.4000	lb/hr			14.1000	lb/hr	DLNC / SCR	
TX-0326	07/20/00	AES Wolf Hollow LP	THE AES Aurora	TX	404	9.0000	ppm15	25.0000	ppm15	12.3000	ppm15	30.1000	lb/hr	41.8000	lb/hr	2.2000	lb/hr	20.5000	lb/hr	SCR	
TX-0296	07/14/00	Wise County Power	Wise County Power Company	TX	230	5.0000	ppm15	9.0000	ppm15	2.0000	ppm15	39.8000	lb/hr	4.8000	lb/hr			10.0000	ppm15	SCR / OC	
AL-0165	06/06/00	Decatur Energy Center	Calpine Construction Corp.	AL	233	0.0130	lb/MM	0.1000	lb/MM	0.0131	lb/MM	0.0050	lb/MM							DLNC / SCR	
TX-0325	05/09/00	Midlothian Energy Project	Midlothian Energy LP	TX	275	5.0000	ppm15	5.0000	ppm15	0.4000	ppm15	24.0000	lb/hr	5.0000	lb/hr			10.0000	ppm15	DLNC / SCR	
TX-0328	02/11/00	Baytown Cogeneration Plant	Baytown Energy Center, LP	TX	250	3.5000	ppm15	228.0000	lb/hr	24.8000	lb/hr	28.3000	lb/hr	28.2000	lb/hr	4.8000	lb/hr	30.9000	lb/hr	DLNC / SCR	

Appendix C

Air Dispersion Modeling Analysis Input & Output Files (CD-ROM)

Figures

Location: J:/E402-000 EMI/GIS/DEIR/DEIR_2.2-1.mxd



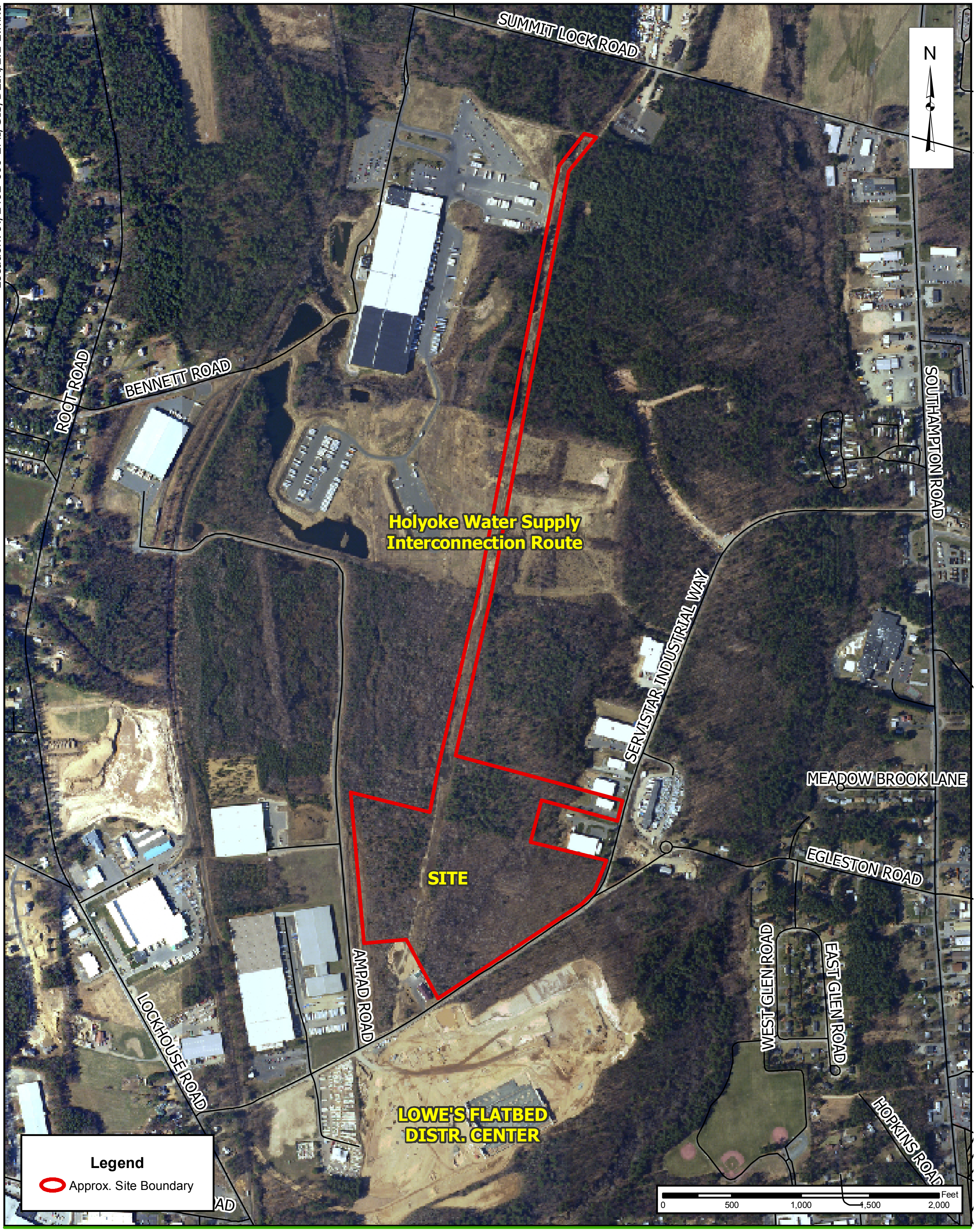
USGS Locus Map

ESS Group, Inc.
Engineers
Scientists
Consultants

PIONEER VALLEY ENERGY CENTER

Scale: 1:22,000
Westfield, Massachusetts
Source: 1) MassGIS, USGS DRG, 1987

Figure 2-1



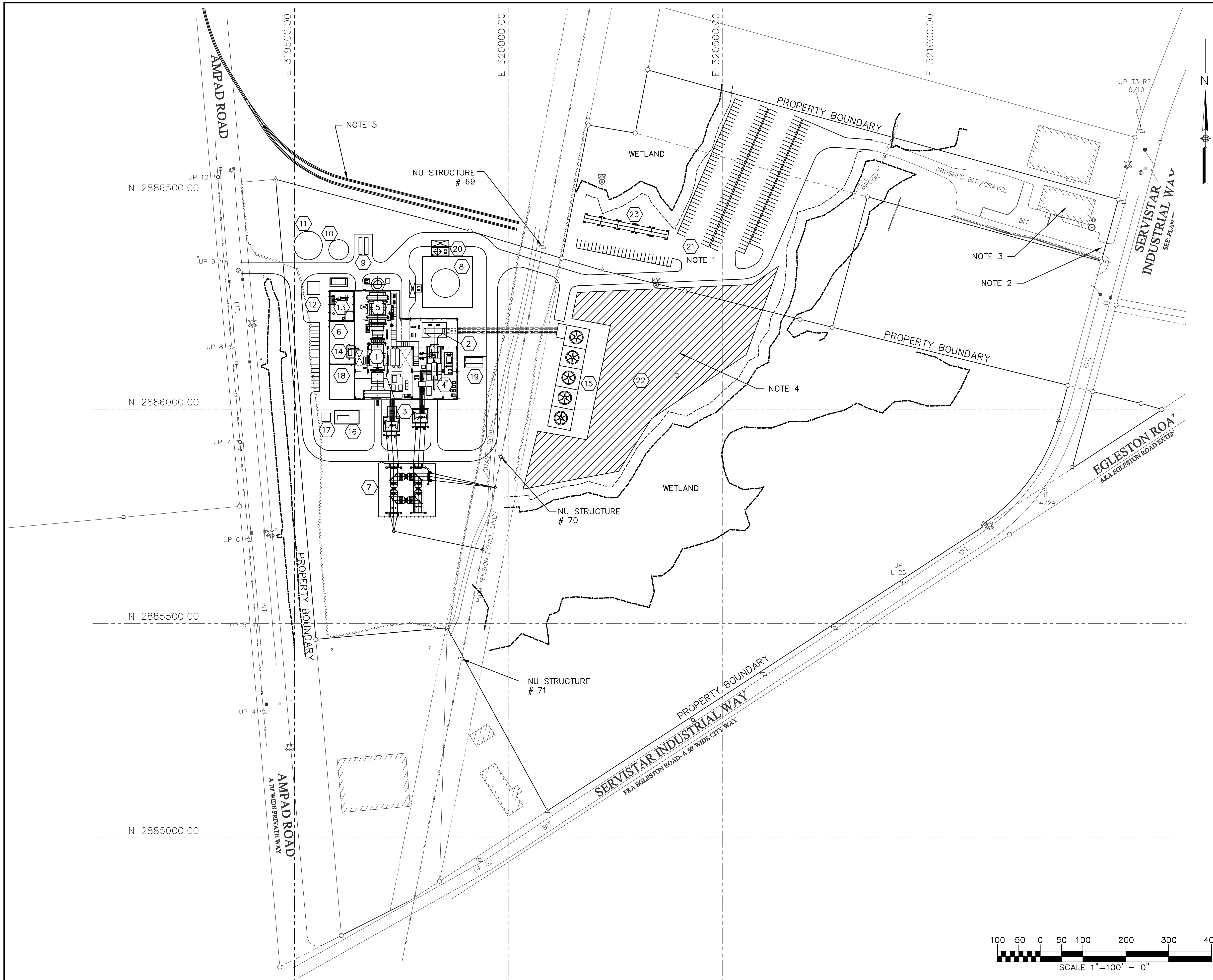
ESS Group, Inc.
Engineers
Scientists
Consultants

PIONEER VALLEY ENERGY CENTER

Aerial Photo of Site and Vicinity

Scale: 1:12,000
Westfield, Massachusetts
Source: 1) MassGIS 1/2 Meter Digital Orthophotograph, 2005

Figure 2-2



LEGEND:

1. COMBUSTION TURBINE GENERATOR
2. CONDENSER
3. STEP-UP TRANSFORMERS
4. STEAM TURBINE GENERATOR
5. HEAT RECOVERY STEAM GENERATOR
6. CONTROL / ADMINISTRATION
7. ELECTRICAL SWITCHYARD
8. FUEL OIL STORAGE TANK
9. LEASED WATER TREATMENT EQUIPMENT
10. DEMINERALIZED WATER STORAGE TANK
11. RAW WATER STORAGE TANK
12. FIRE PUMP HOUSE
13. AUXILIARY BOILER
14. EMERGENCY DIESEL GENERATOR
15. COOLING TOWER
16. FUEL GAS COMPRESSOR
17. FUEL GAS CHROMATOGRAPH / METER BUILDING
18. WAREHOUSE AND MAINTENANCE SHOP
19. HYDROGEN TRAILERS
20. AQUEOUS AMMONIA STORAGE TANK
21. WORKER PARKING
22. CONSTRUCTION LAYDOWN
23. CONSTRUCTION TRAILERS

NOTES:

1. WORKER PARKING SPACES 220.
2. SECONDARY SITE ACCESS DURING CONSTRUCTION.
3. INSIDE STORAGE AND CONSTRUCTION OFFICES IN EXISTING BUILDING.
4. CONSTRUCTION LAYDOWN AREA APPROX. 3 ACRES.
5. AREA OF POTENTIAL RAIL EXTENSION FOR CONSTRUCTION EQUIPMENT DELIVERY.

ISSUE	DATE	DESCRIPTION	BY	CHK'D
F	11/21/08	RELOCATED COOLING TOWER TO ORIGINAL POSITION	JCM	RJL
E	10/22/08	REVISED SWITCHYARD	JCM	RJL
D	9/24/08	ADDED CONSTRUCTION PARKING, LAYDOWN AND EMERGENCY EGRESS	JCM	RJL
C	8/12/08	ISSUED FOR DEIR	JCM	RJL
B	6/5/08	REV LOCATION OF EMERGENCY GEN	JCM	RJL
A	5/20/08	ISSUED FOR EFSB SUBMISSION	JCM	RJL

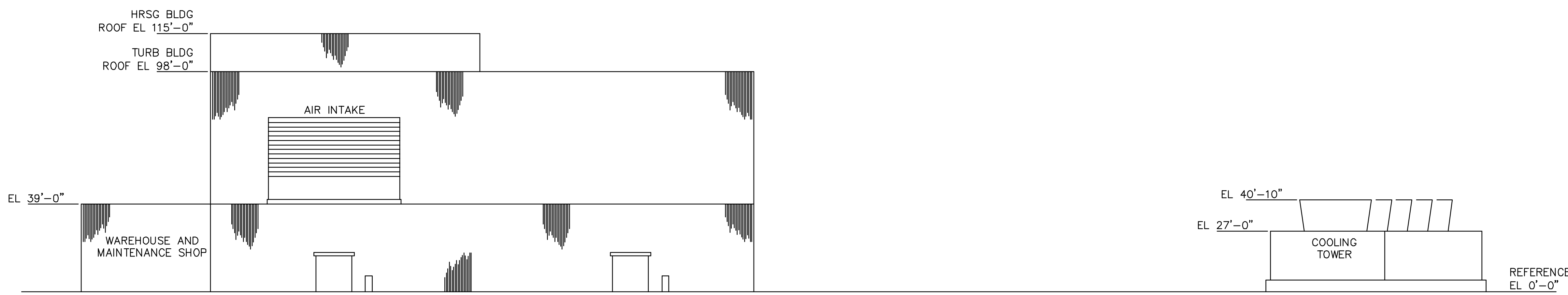
PIONEER VALLEY ENERGY CENTER

PB Power

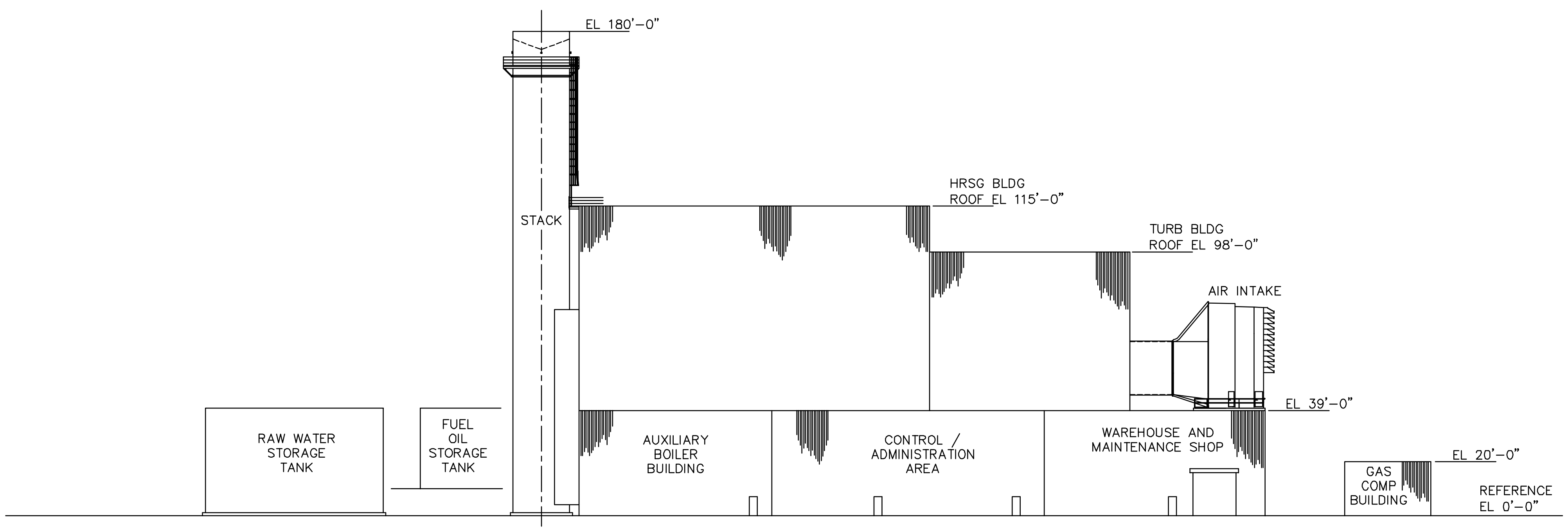
WESTFIELD LAND DEVELOPMENT COMPANY, LLC
PIONEER VALLEY ENERGY CENTER

2-1

DR. JCM	APPROVED DATE	DRAWING NO. G1	REV F
DES.			
CHK.	PRINCIPAL IN CHARGE DATE	SHEET OF	



SECTION B–B
(LOOKING NORTH)



SECTION A–A
(LOOKING EAST)

0 20 40 60 80 100

GRAPHIC SCALE (FEET)

ISSUE	DATE	DESCRIPTION	BY	CHK'D
B	8/12/08	ISSUED FOR DEIR	JCM	RJL
A	5/20/08	ISSUED FOR EFSB SUBMISSION	JCM	RJL

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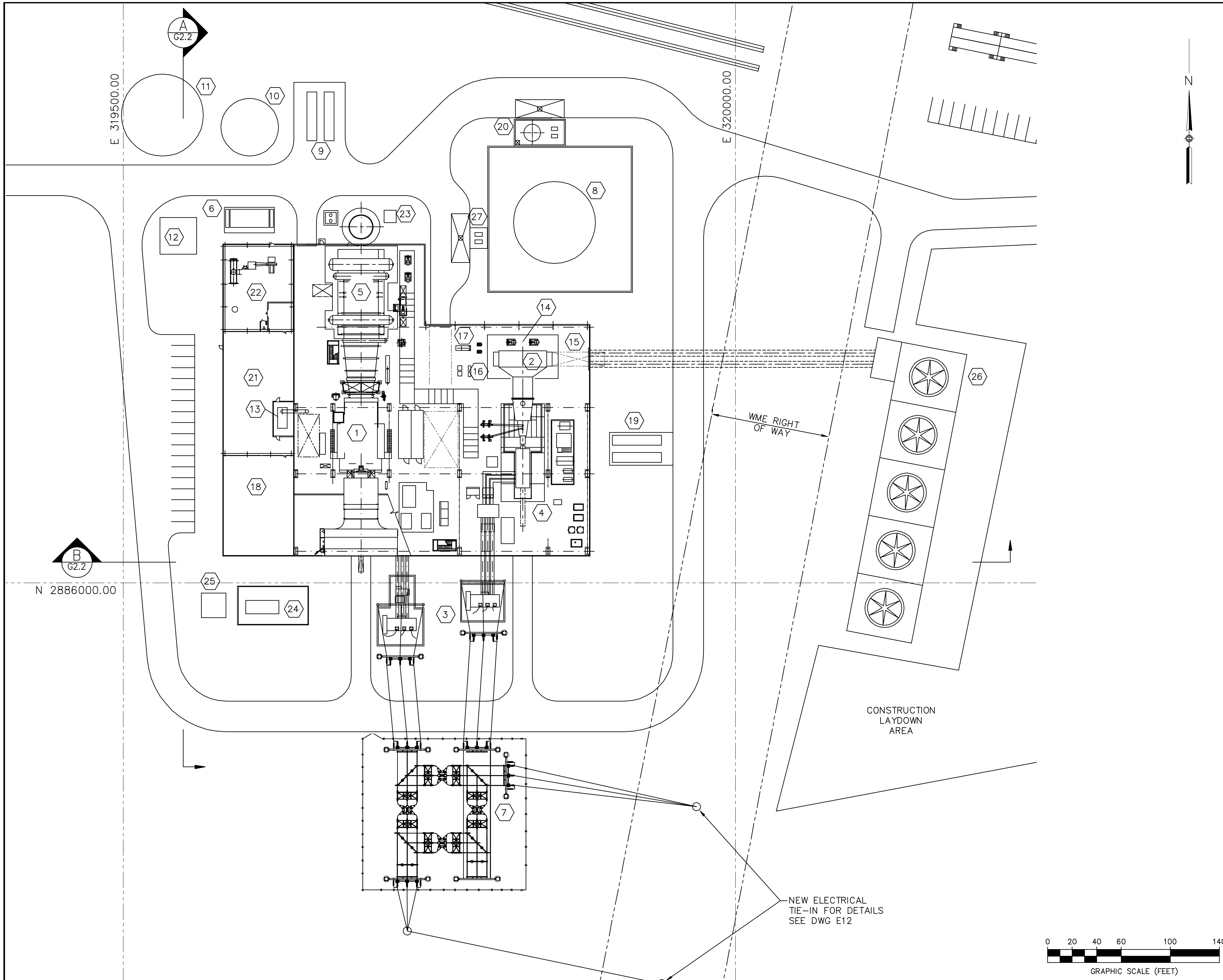
2-1

DR. JCM
DES. JCM
CHK.
APPROVED DATE
PRINCIPAL IN CHARGE DATE
DRAWING NO. G2.2
REV B
SHEET OF



LEGEND:

1. COMBUSTION TURBINE GENERATOR
2. CONDENSER
3. STEP-UP TRANSFORMERS
4. STEAM TURBINE GENERATOR
5. HEAT RECOVERY STEAM GENERATOR
6. TCA COOLER
7. ELECTRICAL SWITCHYARD
8. FUEL OIL STORAGE TANK
9. LEASED WATER TREATMENT EQUIPMENT
10. DEMINERALIZED WATER STORAGE TANK
11. RAW WATER STORAGE TANK
12. FIRE PUMP HOUSE
13. EMERGENCY DIESEL GENERATOR
14. CONDENSATE PUMPS
15. CONDENSER TUBE REMOVAL AREA
16. GLAND STEAM CONDENSER
17. CLOSED LOOP COOLING WATER HEAT EXCHANGER
18. WAREHOUSE AND MAINTENANCE SHOP
19. HYDROGEN TRAILERS
20. AQUEOUS AMMONIA STORAGE TANK
21. CONTROL / ADMINISTRATION
22. AUXILIARY BOILER
23. CEMS ENCLOSURE
24. FUEL GAS COMPRESSOR
25. FUEL GAS CHROMATOGRAPH / METER BUILDING
26. COOLING TOWER
27. FUEL UNLOADING STATION / TRANSFER PUMPS

ISSUE	DATE	DESCRIPTION	BY	CHK'D
E	11/21/08	RELOCATED COOLING TOWER TO ORIGINAL POSITION	JCM	RJL
D	10/22/08	REVISED SWITCHYARD CONFIGURATION	JCM	RJL
C	8/12/08	ISSUED FOR DEIR	JCM	RJL
B	6/5/08	REV LOCATION OF EMERGENCY GEN	JCM	RJL
A	5/20/08	ISSUED FOR EFSB SUBMISSION	JCM	RJL

PIONEER VALLEY ENERGY CENTER

PB Power
A PB Americas, Inc. Company
75 ARLINGTON STREET, BOSTON, MASS. 02116

WESTFIELD LAND DEVELOPMENT COMPANY, LLC
PIONEER VALLEY ENERGY CENTER

2-2

DR. JCM
DES. JCM
CHK.

APPROVED DATE
PRINCIPAL IN CHARGE DATE

DRAWING NO. G2.1
REV E
SHEET OF

Tables

Table 3-1
Maximum Stack Concentrations & Emission Rates

Pollutant	Combustion Turbine Normal Operation			Combustion Turbine Normal Operation			Auxiliary Boiler	Emergency Generator	Fire Pump	Cooling Tower	CT Startup/ Shutdown
	Natural Gas			ULSD			Natural Gas	Diesel	Diesel		Natural Gas
	ppm@15%O_2	lb/MMBtu	lb/hr	ppm@15%O_2	lb/MMBtu	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
NO_x	2.0	0.0080	20.2	5.0	0.021	43.0	0.58	37.5	3.2		62.0
CO	2.0	0.0049	12.3	6.0	0.016	31.5	0.74	12.2	1.9		2,068.0
SO_2		0.0019	4.7		0.0017	3.4	0.010	3.1	0.37		2.9
H_2SO_4		0.0019	4.9		0.0018	3.6					3.0
$PM/PM_{10}/PM_{2.5}$		0.0040	9.8		0.014	26.8	0.10	0.91	0.15	0.010	6.1
CO_2		130	329,700		177	354,300	2,400	2,546	310		199,400
NH_3	2.0	0.0030	7.5	2.0	0.0032	6.4					8.0
VOC	1.0	0.0015	3.6	6.0	0.0090	18.0	0.060	1.7	0.49		2.2
Formaldehyde		0.00028	0.6		0.00031	0.6	0.0015	0.0012	0.00015		0.4

Note: The combustion turbine maximum stack concentrations and emission rates do not apply during normal operation at less than 60% of maximum load.

Table 5-1
Summary of Facility BACT Determinations

Pollutant	Natural Gas Firing			ULSD Firing		
	Proposed Stack Concentration	Proposed Emission Rate	Proposed Control Technology	Proposed Stack Concentration	Proposed Emission Rate	Proposed Control Technology
NO_x BACT	2.0 ppmvd @ 15% O_2		Dry Low-Nox Combustion (DLNC) Selective Catalytic Reduction (SCR)	5.0 ppmvd @ 15% O_2		Water Injection Selective Catalytic Reduction (SCR)
H_2SO_4 BACT		0.0019 lb/MMBtu	Natural Gas Fuel		0.0018 lb/MMBtu	ULSD Fuel
$PM/PM_{10}/PM_{2.5}$ BACT		0.0040 lb/MMBtu	Natural Gas Fuel		0.014 lb/MMBtu	ULSD Fuel
CO BACT	2.0 ppmvd @ 15% O_2		Oxidation Catalyst	6.0 ppmvd @ 15% O_2		Oxidation Catalyst

Table 6-3
Facility Potential Emissions Summary

Pollutant	Potential Total Emissions (tons per year)								PSD
	CT Normal Operation	Auxiliary Boiler	Emergency Generator	Fire Pump	Cooling Tower	PTE - Normal Operation[1]	CT Startup/ Shutdown [2]	Facility PTE[3]	Significance Threshold
Maximum Hours of Operation per Year	8,215	1,100	300	300	8,760		545		
NO_x	91.9	0.3	5.6	0.5	0.0	98.4	12.6	110.9	40
CO	59.9	0.4	1.8	0.3	0.0	62.5	487.4	549.9	100
SO_2	16.7	0.0	0.5	0.1	0.0	17.2	0.8	18.0	40
H_2SO_4	17.2	0.0	0.0	0.0	0.0	17.2	0.8	18.0	7
$PM/PM_{10}/PM_{2.5}$ (Total)	49.1	0.1	0.1	0.0	0.04	49.4	1.7	51.0	25/15/10
$PM/PM_{10}/PM_{2.5}$ (Filterable)	24.6	0.0	0.1	0.0	0.02	24.7	0.8	25.5	25/15/10
$PM/PM_{10}/PM_{2.5}$ (Condensible)	24.6	0.0	0.1	0.0	0.02	24.7	0.8	25.5	25/15/10
CO_2	1,250,005	1,386	382	46	0	1,251,819	54,337	1,306,156	NA
NH_3	27.3	0.0	0.0	0.0	0.0	27.3	1.4	28.8	NA
VOC	23.8	0.0	0.3	0.1	0.0	24.2	0.6	24.8	40
Lead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Formaldehyde	2.5	0.0	0.0	0.0	0.0	2.5	0.1	2.6	NA
Total HAPS	5.1	0.0	0.0	0.0	0.0	5.1	0.2	5.3	NA

[1] Total emissions represent maximum potential of all equipment operating independently in normal operation. As all equipment will not run for maximum potential hours shown, actual emissions will be less.

[2] Startup/shutdown emissions have been estimated assuming a total of 176 startups & shutdowns per year. It has been assumed that 80% of the startups will be warm starts, while 20% will be cold starts.

[3] The Facility PTE is the sum of the PTE during normal operation and during startup/shutdown of the CT.

Table 6-4
Pioneer Valley Energy Center
GEP Stack Height Analysis

Building Tiers	Height (ft)	Projected Width (ft)	Formula GEP Height (ft)	Stacks > GEP Height	Building Distance from Stack (ft)				'5L' Distance (ft)	Stacks within 5L?
					Turbine	Auxiliary Boiler	Generator	Fire Pump		
HRSG only	115	177	287.5	None	5	0	0	90	575	All
Turbines & HRSG	98	312	245	None	5	0	0	90	490	All
HRSG, Turbines, & Operations Center	39	608	97.5	All but fire pump	5	0	0	55	195	All

Table 6-5
Pioneer Valley Energy Center
Cavity Analysis

Building Tiers	Height (ft)	Projected Width (ft)	Cavity Height (1.5L) (ft)	Stacks > Cavity Height	Cavity Region Distance (ft)	Stacks Within Cavity Region	Distance From Property Line (ft)	Cavity Extends Offsite?
HRSG	115	177	172.5	None	345	All	140	Yes
HRSG & Turbines	98	312	147	Turbine only	294	All	140	Yes
HRSG, Turbines & Operations Center	39	608	58.5	All but fire pump	117	All	90	Yes

Table 6-6
Pioneer Valley Energy Center
Stability Class/Wind Speed Combinations Used for the Screening Modeling

Stability Class	Wind Speed (m/sec)
A	1, 1.5, 2, 2.5, 3
B	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5
C	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5, 8, 10
D	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5, 8, 10, 15, 20
E	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5
F	1, 1.5, 2, 2.5, 3, 3.5, 4

Table 6-7
Pioneer Valley Energy Center
Wind Speed/Mixing Height Combinations Used for the Screening Modeling

Wind Speed (m/sec)	Mixing Height (m)
1	320
1.5	480
2	640
2.5	800
3	960
3.5	1,120
4	1,280
4.5	1,440
5	1,600
8	2,560
10	3,200
15	4,800
20	6,400

Table 6-8
Pioneer Valley Energy Center
Simple Terrain Screening Receptor Distances and Elevations

Distance (km)	Elevation (meters mean sea level)	Elevation (meters above stack base)
0.106	74	1
0.2	77	4
0.3	83	10
0.4	90	17
0.5	90	17
0.6	90	17
0.7	90	17
0.8	91	18
0.9	91	18
1.0	91	18
1.1	91	18
1.2	91	18
1.3	91	18
1.4	91	18
1.5	91	18
1.6	91	18
1.7	91	18
1.8	91	18
1.9	91	18
2.0	91	18
2.2	91	18
2.4	91	18
2.6	97	24
2.8	119	46
3.0-20	137	55

Table 6-9
Pioneer Valley Energy Center
Complex Terrain Screening Receptor Elevations and Distances

Elevation (meters above mean sea level)	Elevation (meters above stack base)	Distance (km)	Elevation (meters above mean sea level)	Elevation (meters above stack base)	Distance (km)
128.0-140.2	55-67	2.97	356.6-359.7	283-287	10.42
143.3	70	4.46	362.7-368.8	290-296	10.43
146.3-149.4	73-76	4.47	371.9	299	10.44
152.4	79	4.48	374.9	302	10.45
155.5-158.5	82-85	4.49	378.0	305	10.47
161.5-167.6	88-94	4.50	381.0	308	10.48
170.7-173.7	98-101	4.51	384.1	311	10.49
176.8	104	4.52	387.1-390.1	314-317	10.50
179.8-185.9	107-113	4.53	393.2-396.2	320-323	10.51
189.0-192.0	116-119	4.54	399.3-402.3	326-329	10.52
195.1	122	4.57	405.4	332	10.53
198.1	125	4.59	408.4-411.5	335-338	10.54
201.2-204.2	128-131	4.60	414.5-429.8	341-357	10.55
207.3-214.4	134-140	4.62	432.8	360	10.57
216.4	143	7.44	435.9	363	10.59
219.5	146	7.47	438.9	366	10.60
222.5-255.6	149-152	7.71	442.0	369	10.61
228.6	155	7.81	445.0	372	10.62
231.7	158	7.93	448.1-451.1	375-378	10.65
234.7	162	8.18	454.2	381	17.90
237.7-271.3	165-198	8.37	457.2	384	17.94
274.3-301.8	201-229	8.41	460.3	387	18.00
304.8-329.2	232-256	8.46	463.3	390	18.06
332.2-341.4	259-268	8.53	466.3	393	18.15
344.4-347.5	271-274	10.16	469.4	369	19.97
350.5	277	10.17	472.4-487.7	399-415	20.00
353.6	280	10.18			

Table 6-17
Pioneer Valley Energy Center
Refined Modeling - Maximum 24-Hour $PM_{2.5}$ Concentrations

Sources	Turbine and Auxiliary Boiler				
Load	60%	60%	60%	60%	60%
Time Period	4/4/1991	6/27/1994	2/5/1995	4/5/1995	2/5/1995
Location					
	686960	686748	686998	687010	687047
UTM E (meters)	4669621	4670412	4669789	4669692	4669771
Concentration (ug/m3) UTM N (meters)	1.78	1.71	1.79	1.77	1.76
Sources	Generator and Fire Pump Testing				
Time Period	1/24/1991	10/12/1994	12/15/1995	1/12/1995	12/15/1995
Location					
	686960	686748	686998	687010	687047
UTM E (meters)	4669621	4670412	4669789	4669692	4669771
Concentration (ug/m3) UTM N (meters)					
	3.38	1.29	2.55	3.50	2.49
1-hr r	0.14	0.05	0.11	0.15	0.10
24-h					
Total Concentration (ug/m3)	1.92	1.76	1.90	1.92	1.86
SIL	2	2	2	2	2

1 - 1-hr PM values from the generator and firepump are based on maintenance only between 8am and 5pm.

Table 6-18
Pioneer Valley Energy Center
Background Concentration Values (2005-2007)

Pollutant	Averaging Period	2005	2006	2007	Background
CO	1-hr	3.3 ppm Liberty P-Lot, Springfield, MA	3.1 ppm Liberty P-Lot, Springfield, MA	2.1 ppm Liberty P-Lot, Springfield, MA	3.3 ppm 3,843 $\mu g/m^3$
	8-hr	2.6 ppm Liberty P-Lot, Springfield, MA	2.4 ppm Liberty P-Lot, Springfield, MA	1.3 ppm Liberty P-Lot, Springfield, MA	2.6 ppm 3,028 $\mu g/m^3$
NO_2	Annual	0.010 ppm Anderson Rd, AFB, Chicopee, MA	0.010 ppm Anderson Rd, AFB, Chicopee, MA	0.009 ppm Anderson Rd, AFB, Chicopee, MA	0.010 ppm 19.1 $\mu g/m^3$
$PM_{2.5}$	24-hr	26 $\mu g/m^3$ Anderson Rd, AFB, Chicopee, MA	29 $\mu g/m^3$ Anderson Rd, AFB, Chicopee, MA	30 $\mu g/m^3$ Anderson Rd, AFB, Chicopee, MA	28.3 $\mu g/m^3$ *(average)*
	Annual	10.6 $\mu g/m^3$ Anderson Rd, AFB, Chicopee, MA	9.2 $\mu g/m^3$ Anderson Rd, AFB, Chicopee, MA	10.2 $\mu g/m^3$ Anderson Rd, AFB, Chicopee, MA	10.0 $\mu g/m^3$ *(average)*
PM_{10}	24-hr	53 $\mu g/m^3$ 1860 Main St, Springfield, MA	49 $\mu g/m^3$ 1860 Main St, Springfield, MA	35 $\mu g/m^3$ 1860 Main St, Springfield, MA	53 $\mu g/m^3$
	Annual	23 $\mu g/m^3$ 1860 Main St, Springfield, MA	19 $\mu g/m^3$ 1860 Main St, Springfield, MA	18 $\mu g/m^3$ 1860 Main St, Springfield, MA	23 $\mu g/m^3$
SO_2	3-hr	0.037 ppm Liberty P-Lot, Springfield, MA	0.030 ppm Liberty P-Lot, Springfield, MA	0.030 ppm Liberty P-Lot, Springfield, MA	0.037 ppm 99 $\mu g/m^3$
	24-hr	0.021 ppm Liberty P-Lot, Springfield, MA	0.017 ppm Liberty P-Lot, Springfield, MA	0.016 ppm Liberty P-Lot, Springfield, MA	0.021 ppm 56 $\mu g/m^3$
	Annual	0.006 ppm Liberty P-Lot, Springfield, MA	0.004 ppm Liberty P-Lot, Springfield, MA	0.003 ppm Liberty P-Lot, Springfield, MA	0.006 ppm 16 $\mu g/m^3$

Notes:
1. The short-term CO, PM_{10}, and SO_2 background concentrations (1-hr, 3-hr, 8-hr, and 24-hour) are the highest of the second-high values.
2. The annual NO_2 and SO_2 background concentrations are the highest of the annual mean values.
3. The 24-hour $PM_{2.5}$ background concentration is the 3-year average of the 98th percentile values.
4. The annual $PM_{2.5}$ background concentration is the 3-year average of the annual mean values.
5. Background values selected were the highest values meeting the above criteria from among the monitors in Springfield and Chicopee MA, over the most recent 3-year period (2005-2007).

Table 6-19
Pioneer Valley Energy Center
Comparison of Project Impacts to SILs and NAAQS

Pollutant	Averaging Period	NAAQS (ug/M^3)	Significant Impact Level (ug/M^3)	Maximum Project Impacts		Background Concentrations (ug/M^3)	Total Predicted Ambient Concentrations	
				(ug/M^3)	% of SIL		(ug/M^3)	% of NAAQS
CO	1-hr	40,000	2000	104.2	5%	3843	3947	10%
	8-hr	10,000	500	18.2	4%	3028	3046	30%
NO_2	Annual	100	1	0.6	60%	19.1	20	20%
PM_{10}	24-hr	150	5	1.9	38%	53	55	37%
$PM_{2.5}$	24-hr	35	2	1.9	95%	28.3	30	86%
	Annual	15	0.3	0.2	67%	10.0	10	67%
SO_2	3-hr	1300	25	2.0	8%	99	101	8%
	24-hr	365	5	0.4	8%	56	56	15%
	Annual	80	1	0.04	4%	16	16	20%

Table 6-20
Pioneer Valley Energy Center
Comparison of Project Concentrations to PSD Increments

Pollutant	Averaging Period	Maximum Project Impacts (ug/M^3)	PSD Increment
NO_2	Annual	0.6	25
PM_{10}	24-hr	1.9	30
	Annual	0.2	17
SO_2	3-hr	2.0	512
	24-hr	0.4	91
	Annual	0.04	20

Table 6-21
Summary of Modeled Ambient Air Impacts on Soils and Vegetation

Pollutant	Averaging Time	Modeling Results (μg/m^3)			Background (μg/m^3)	Total Impact (μg/m^3)	Sensitivity Screening Levels (μg/m^3)[1]		
		Modeled Impact	Scaling Factor	Impact			Sensitive	Intermediate	Resistant
SO_2	1 hr		1.11	2.2	149	151	917	NA	NA
	3 hrs	2.0	1.00	2.0	99	101	786	2,096	13,100
	1 year	0.04	1.00	0.04	16	16	18	18	18
NO_2	4 hrs		11.25	6.8	94	101	3,760	9,400	16,920
	8 hrs		8.75	5.3	94	99	3,760	7,520	15,040
	1 month		5.00	3.0	94	97	564	564	564
	1 year	0.6	1.00	0.6	19	20	94	94	94
CO	1 hour	104.2	1.00	104.2	40,000	40,104	NA	NA	NA
	1 week		0.4	41.7	3,028	3,070	1,800,000	NA	18,000,000

[1] The Sensitivity Screening Levels are from Table 3.1 of the EPA's "A Screening Procedure for the Impacts of Air Pollution on Plants, Soils and Animals" (EPA, 1980)

Prevention of Significant Deterioration Permit Application

PIONEER VALLEY ENERGY CENTER
AMPAD ROAD
WESTFIELD, MASSACHUSETTS

SUBMITTED TO	United States Environmental Protection Agency Region I Office New Source Review 1 Congress Street, Suite 1100 Boston, Massachusetts 02114-2023
PREPARED FOR	Westfield Land Development Company LLC 102 Elm Street, Suite 15 Westfield, Massachusetts 01085
PREPARED BY	ESS Group, Inc. 888 Worcester Street, Suite 240 Wellesley, Massachusetts 02482 ESS Project No. E402-007.1 November 24, 2008

ESS Group, Inc.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION
Pioneer Valley Energy Center
Ampad Road
Westfield, Massachusetts

Prepared For:

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102 Elm Street, Suite 15
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ESS Project No. E402-007.1

November 24 , 2008

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ESS Group, Inc.

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1.0 INTRODUCTION

This document is a Prevention of Significant Deterioration (PSD) Permit Application for the Pioneer Valley Energy Center (PVEC, the Facility) on Ampad Road in Westfield, Massachusetts. This 400 megawatt (MW) generating facility will be developed by Westfield Land Development Company, LLC (WLDC). Delegated authority for the PSD program is no longer retained by the Massachusetts Department of Environmental Protection (MassDEP); the US EPA currently implements the PSD rules for major sources and major modifications in Massachusetts. This PSD Permit Application has been prepared for submittal to the United States Environmental Protection Agency's (US EPA) Region I Office.

The US EPA's PSD regulations (40 CFR 52.21), apply to any new major stationary source located in an area that is designated as being in attainment or unclassifiable with the National Ambient Air Quality Standards (NAAQS). The Facility, as a fossil fuel fired electric steam generating plant of more than 250 million British thermal units per hour (MMBtu/hr) heat input, with the potential to emit 100 tons or more per year of a regulated New Source Review (NSR) pollutant (NO_2 and CO), meets the definition of a major stationary source contained in the PSD rules. Massachusetts is designated as being in attainment with the NAAQS for all pollutants except ozone. As a new major stationary source in an attainment area, the Facility is subject to the PSD rules, and requires a PSD Permit prior to construction.

Because the Facility will include a combustion turbine with a rated output greater than 10 MW, the project exceeds the minimum output threshold that requires a Plan Approval under the Massachusetts Air Pollution Control regulations. The regulations specify that a new major stationary source with a combustion turbine of this size also requires the filing of a Major Comprehensive Plan Approval (MCPA) with the MassDEP, including compliance with the state Nonattainment Review (310 CMR 7.00, Appendix A) regulations. A separate application has been submitted to MassDEP to satisfy the state Pre-Construction Permitting and Nonattainment Review requirements.

The PSD program requires a new major stationary source to meet each applicable emissions limitation under the State Implementation Plan (SIP) and each applicable emissions standard and standard of performance under 40 CFR Parts 60 and 61. It also requires a new major stationary source to apply Best Available Control Technology (BACT) for each regulated NSR pollutant that it has the potential to emit in significant amounts, and to demonstrate that the allowable emissions from the proposed source will not cause or contribute to air pollution in violation of NAAQS or any applicable maximum allowable increase over the baseline concentration in any area.

The PSD rules contain requirements for a pre-construction analysis of the ambient air quality for each pollutant the source would have the potential to emit in a significant amount in the area the source would affect, as well as post-construction monitoring as the EPA determines is necessary to determine the effect emissions from the stationary source may have on air quality in any area. They also contain requirements for an analysis of the impairment to soils and vegetation that would occur as a result of the source.

Section 2 of this application provides a brief description of the Facility. The potential emissions associated with the Facility are detailed in Section 3. Section 4 summarizes the regulatory framework and applicable requirements for the Facility. Section 5 details the BACT analysis conducted for this

Facility for each pollutant. The air dispersion modeling analysis conducted for the Facility is detailed in Section 6.

2.0 FACILITY DESCRIPTION

The Facility will consist of a combined-cycle power train using state-of-the-art electric generating technology to achieve reliable operation and low emissions, while generating up to 431 MW of power. Figure 2-1 is a USGS locus map and Figure 2-2 is an aerial photograph of the site and the vicinity. A site plan has been included as Figure 2-3. The building elevations are shown of Figure 2-4. Figure 2-5 is a general arrangement plan.

The combined-cycle power train will consist of a Mitsubishi M501G air-cooled combustion turbine with a direct connected electric generator and a heat recovery steam generator (HRSG) that will supply high pressure superheated steam to a steam turbine generator. The combustion turbine will fire natural gas as a primary fuel and will utilize Ultra Low Sulfur Distillate (ULSD) fuel as a backup fuel. The combustion turbine will have a maximum heat input rate of 2,542 million British thermal units per hour (MMBtu/hr) and a maximum gross power output (including the steam turbine) of 431 MW while firing natural gas. The maximum heat input rate and gross power output will be 2,016 MMBtu/hr and 306 MW, respectively, while firing ULSD fuel.

The turbine will be equipped with a Selective Catalytic Reduction (SCR) emissions control system to minimize emissions of nitrogen oxides (NO_x) and an oxidation catalyst to minimize emissions of carbon monoxide (CO) and volatile organic compounds (VOC). Exhaust gases from the combustion turbine will be discharged through an exhaust stack, 23 feet in diameter and 180 feet tall. There will also be an auxiliary boiler and an emergency generator associated with the Facility that will be housed within the main plant building. The auxiliary boiler will have a maximum heat input rate of approximately 21 MMBtu/hr and will be fired by natural gas. The diesel-powered emergency generator will have a power output of approximately 2,174 horsepower (hp). A separate, small building located to the north of the main plant building will contain a 270-hp diesel-powered emergency fire water pump system. The diesel powered equipment will be fueled with ULSD fuel oil, and/or ULSD blended with biodiesel fuel.

The Facility will also include a mechanical draft wet cooling tower equipped with drift eliminators, an electrical switchyard, and on-site tanks for the storage of ULSD fuel along with water and aqueous ammonia used by the combustion turbine's emissions control system. Other pieces of support equipment located outside the building will include an auxiliary lube-oil cooling system, water purification systems, and a fuel gas compressor and metering station.

There will be no restrictions on the daily operation of the combustion turbine. The combustion turbine will be permitted for unrestricted annual operation on natural gas and for the equivalent usage of up to 1,440 hours per year of operation at its maximum firing rate on ULSD. The maximum heat input rate to the combustion turbine while firing ULSD is approximately 2,016.1 MMBtu/hr. This heat input rate is equivalent to approximately 14,609 gallons per hour at an average heating value of 138,000 Btu/gallon. Therefore, combustion turbine ULSD usage will be limited to 21.0 million gallons per 12-month period. WLDC will record its ULSD usage on a monthly basis to demonstrate compliance with its 12-month rolling ULSD usage limit.

The auxiliary boiler will be limited to the equivalent of no more than 1,100 hours of operation per year at maximum heat input. The emergency generator and fire pump will each be limited to no more than 300 hours of operation per year. Other than one hour per week for maintenance and testing, which will only occur between the hours of 8 AM and 5 PM, the diesel generator and fire pump will not operate concurrently with the combustion turbine. WLDC will record the hourly operation of the auxiliary boiler, emergency generator, and fire pump on a monthly basis to demonstrate compliance with the 12-month rolling operating hour limitations.

3.0 FACILITY EMISSIONS

The Facility will provide the highest level of emissions control technically and economically feasible for a combined-cycle power generating facility. The Facility will be required to implement BACT for each regulated NSR pollutant that it would have the potential to emit in significant amounts, as defined in the PSD regulation. As shown on Table 6-3, the regulated NSR pollutants which the Facility has the potential to emit in significant amounts are nitrogen oxides (NO_x), carbon monoxide (CO), sulfuric acid mist (H_2SO_4), particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). The Facility is also subject to the applicable emissions limitations contained in the federal New Source Performance Standards (NSPS) for combustion turbines.

The air contaminants potentially emitted by the combustion turbine and the specific measures that will be used to meet the BACT and NSPS requirements and minimize those emissions are discussed below. The emission limits and performance standards for the other sources at the Facility are detailed in Section 4.3.1. Table 3.1 summarizes the maximum stack concentrations and hourly emission rates from each of the emission sources at the Facility for each fuel fired.

3.1 Nitrogen Oxides

Combustion turbines produce NO_x emissions from the oxidation of nitrogen contained in both the fuel being fired and the combustion air. The fuel-bound nitrogen content of natural gas is the lowest of any fossil fuel. The fuel-bound nitrogen in the USLD fuel that will be used as a back-up fuel for the Facility is lower than that found in any other liquid fossil fuel. High combustion temperatures cause "thermal" NO_x emissions to occur in many combustion turbines. Mitsubishi combustion turbines utilize specially designed combustors to minimize combustion temperatures and resulting NO_x formation. The combustion turbine system is designed to limit NO_x emissions to approximately 20 parts per million by volume on a dry basis (ppmvd) while firing natural gas, and to 42 ppmvd while firing ULSD, prior to additional controls.

Further NO_x emission control will be achieved by an SCR system. SCR removes NO_x from the combustion turbine exhaust gas stream by the injection of vaporized aqueous ammonia into the hot exhaust gas path where it passes through a catalyst grid. The catalyst causes a chemical reaction between the ammonia and the hot stack gases which reduces most of the NO_x to nitrogen and water. The Facility will also utilize water injection for NO_x emissions control during ULSD firing. NO_x emissions will be reduced by approximately 90% by the SCR system, to no more than 2 ppmvd corrected to a flue gas oxygen concentration of 15 percent (ppmvd@15%O_2) while firing natural gas, and to no more than 5 ppmvd@15%O_2 while firing ULSD fuel.

3.2 Sulfur Dioxide / Sulfuric Acid

Emissions of sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) are formed from oxidation of sulfur in fuel. Given that flue gas desulfurization systems have not been applied to combustion turbine facilities, the only means for controlling SO_2 and H_2SO_4 emissions from the Facility is to limit the sulfur content of the fuel. Natural gas has very low sulfur content, resulting in the lowest SO_2 and H_2SO_4 emission rates achievable for a combustion turbine. Because ULSD contains only 15 parts per million of sulfur, SO_2 and H_2SO_4 emissions will be minimized to the maximum possible extent for any liquid fuel fired combustion turbine. The use of natural gas and ULSD fuel will result in SO_2 emission rates no greater than 0.0019 lb/MMBtu of heat input to the turbine firing natural gas and 0.0017 lb/MMBtu firing ULSD. The H_2SO_4 emission rates will be no greater than 0.0019 lb/MMBtu while firing natural gas and 0.0018 lb/MMBtu while firing ULSD.

3.3 Particulate Matter

PM emissions from fuel combustion are primarily the result of non-combustible constituents (ash) in the fuel. In less efficient combustion systems, particulate may also be comprised of soot resulting from unburned hydrocarbons. In combustion systems that utilize SCR controls, a small fraction of the particulate emissions is ammonium bisulfate compounds formed when the ammonia reagent reacts with sulfur trioxide.

For combustion turbines, all PM is typically less than 10 microns in diameter (PM_{10}). Although logically a subset of PM_{10}, the emissions of fine particulate matter ($PM_{2.5}$) from the turbine have been conservatively assumed to be equal to the emissions of PM_{10}. It has also been conservatively assumed that the turbine's $PM_{2.5}$ emissions' filterable and condensable fractions are equal (each 50% of the total).

The type of fuel, the design and operation of the turbine, and the SCR system design and operation will each impact the formation of PM emissions. Add-on particulate controls such as electrostatic precipitators, fabric filters or wet scrubbers are not technically feasible for combustion turbines. Rather, particulate emission control is achieved at the source by efficiently burning low ash and low sulfur fuel. The Facility will use natural gas and ULSD fuel only, combined with state-of-the-art combustion technology and operating controls, to provide the most stringent degree of particulate emissions control available for combustion turbines. These measures will result in a $PM/PM_{10}/PM_{2.5}$ emission rate no greater than 0.0040 lb/MMBtu of heat input to the turbine while firing natural gas, and 0.014 lb/MMBtu while firing ULSD.

3.4 Carbon Monoxide

CO emissions are formed due to incomplete combustion of the fuel typically caused by insufficient residence time, temperature, turbulence, or oxygen to combine unburned carbon with oxygen at high temperatures. CO emissions are typically higher during transient and low load operating conditions. Control technologies used to minimize CO emissions include the use of clean burning fuels, state-of-the-art combustion technology, add-on oxidation catalyst systems, and establishing minimum load restrictions.

The combustion turbine proposed for the Facility will use a combustor design and configuration that achieves among the lowest CO emission rate of any similar type of unit. The clean burning nature of natural gas and ULSD fuel further minimizes CO emissions due to unburned carbon. Additional reduction of CO emissions will come from an oxidation catalyst located in the HRSG. Except during periods of startup and shutdown, the combustion turbine will operate at greater than 60% load and will achieve combustion temperatures high enough to minimize CO formation in the combustion process.

The design and configuration of the combustion equipment, the use of natural gas and ULSD fuels, and the use of an oxidation catalyst will maintain the CO stack concentration to no more than 2 ppmvd@15%O_2 while firing natural gas, and 6 ppmvd@15%O_2 while firing ULSD fuel, at operating loads of 60% of full load and greater.

3.5 Volatile Organic Compounds

Much like CO, VOC emissions are generated due to incomplete combustion of fuel. Control technologies used to minimize VOC emissions include the use of clean burning fuels, state-of-the-art combustion technology, add-on oxidation catalyst systems, and establishing minimum load restrictions.

The combustion turbine proposed for the Facility will use a combustor design and configuration that achieves among the lowest VOC emission rate of any similar type of unit. The clean burning nature of natural gas and ULSD fuel further minimizes VOC emissions due to unburned carbon. Additional reduction of VOC emissions will come from an oxidation catalyst located in the HRSG. Except during periods of startup and shutdown, the combustion turbine will operate at greater than 60% load and will achieve combustion temperatures high enough to minimize VOC formation in the combustion process.

The design and configuration of the combustion equipment, the use of natural gas and ULSD fuels, and the use of an oxidation catalyst will maintain the VOC stack concentration to no more than 1 ppmvw@15%O_2 while firing natural gas, and 6 ppmvw@15%O_2 while firing ULSD fuel, at operating loads of 60% of full load and greater.

3.6 Ammonia (NH_3)

The SCR emissions control systems will reduce the NO_X emissions from the turbine by injecting NH_3 into the exhaust gas stream upstream of a catalyst. The NO_X and NH_3 react on the surface of the catalyst to form nitrogen (N_2) and water (H_2O). Some portion of the injected NH_3 will pass through the catalyst unreacted. These unreacted NH_3 emissions are referred to as NH_3 slip. The SCR system to be utilized at this facility will be designed to maintain a stack NH_3 slip concentration of no greater than 2 ppmvd@15%O_2 while firing natural gas and while firing ULSD fuel.

3.7 Carbon Dioxide

Carbon dioxide (CO_2) emissions are produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

There are no add-on controls available for CO_2 emissions for the Facility. The Facility has been designed to provide a high level of CO_2 mitigation for an energy generating facility, primarily by the use of clean-burning fuels and highly efficient combustion and power generating technology. Another way the Facility design has been optimized for CO_2 mitigation is the use of a wet cooling tower. The use of a mechanical draft wet cooling tower is a more effective means of reducing the steam pressure in the condenser than an air cooled condenser. This increase in efficiency results in a reduction of nearly 51 MMBtu/hr of additional heat input or an additional 51,000 ft^3/hr of natural gas from a water cooled facility compared to air cooled to produce the same amount of power. The additional heat input that would be required to produce the same power output using an air cooled condenser would result in a proportional increase in CO_2 emissions.

The Facility's average annual CO_2 emission rate of approximately 831 lb/MW-hr is significantly lower than the marginal emission rates reported for New England (993 lb/MW-hr) and Massachusetts (1,015 lb/MW-hr) by ISO-NE for 2006. The Facility may displace energy currently being provided by less efficient, higher CO_2 emitting sources, and will help continue the downward trend of the ISO-NE marginal CO_2 emission rates exhibited over the past 15 years. The Facility's emissions of CO_2 will also be regulated and limited by its allowances obtained under the MassDEP CO_2 Budget Trading Program.

3.8 Hazardous Air Pollutants (HAPS)

Combustion turbines generally have lower HAP emissions than other combustion sources due to the high combustion temperatures reached during normal operation. According to EPA's reference document "AP-42 – A Compilation of Air Pollutant emissions Factors," the primary HAPs emitted from natural gas and distillate oil fired combustion turbines are formaldehyde, polycyclic aromatic hydrocarbons (PAH), benzene, toluene, and xylenes, while small amounts of metallic HAP carried over from the fuel constituents are also present in the emissions from distillate-oil fired turbines.

Much like CO and VOC, most HAP emissions are generated due to incomplete combustion of fuel. The control technologies for minimizing HAP emissions achieved in practice are combustion control and the use of an oxidation catalyst. Combustion control includes proper time, temperature, and mixing within the combustor to allow for the most complete burning possible. The use of an oxidation catalyst in the HRSG will further reduce the HAP emissions from the combustion turbine. The turbine combustor design and the use of an oxidation catalyst will minimize the HAP emissions in the combustion turbine exhaust.

3.9 Summary of Potential Pollutant Emissions

The control measures discussed above will minimize emissions to the maximum extent feasible for the combustion turbine. The resulting emission rates, per unit of power generated by the Facility, will be lower than many existing base-load and peaking power facilities, and well below most existing demand response resources such as emergency engines located at commercial and industrial facilities. The potential annual emissions of the Facility, including the emissions from all of the proposed combustion sources and from the wet cooling tower, are shown in Table 6-3.

The potential pollutant emissions presented in Table 6-3 represent the potential emissions from each source operated at its maximum operating load at the most representative average ambient conditions at its maximum permitted annual hourly operation. As all equipment will not operate at the maximum permitted annual hours, the actual emissions from the Facility will be significantly lower.

Table 6-3 also includes an estimate of the total potential emissions from the combustion turbine during periods of startup and shutdown. A total of 176 startups and shutdowns have been assumed for the Facility. It has been further assumed that approximately 80% of the startups will be warm starts, while the remaining 20% of the startups will be cold starts. WLDC is proposing to limit potential emissions during startup and shutdown activities to the total tons per rolling 12-month period shown in Table 6-3, without limitation on the total number and type (hot, warm, cold) of events.

As shown in Table 6-3, the potential total HAP emissions from the Facility will not exceed the major source threshold of 25 tons per year or more. The Facility's potential emissions of formaldehyde, the single HAP with the highest annual potential emissions, will not exceed the major source threshold of 10 tons per year or more. The Facility will therefore not be a major source of HAP emissions.

4.0 REGULATORY FRAMEWORK

The US EPA and the MassDEP have established regulations to ensure that emissions sources such as those proposed for the Facility do not result in adverse impacts to human health or the environment. This section provides a discussion of the applicability of many of those regulations, a summary of the requirements imposed by the regulations that apply to the Facility, and a discussion of how the applicable requirements will be met. Appropriate compliance certifications and monitoring conditions for each applicable requirement are discussed below and presented in the application forms contained in Section 9.0 of this document.

4.1 Federal and State Permitting Requirements

4.1.1 Major Comprehensive Plan Approval

As a new emissions source that will utilize natural gas fuel and have a heat input rating greater than 40 million Btu per hour, and with a combustion turbine with a rated output greater than 10 MW, the Facility will require a Pre-Construction Plan Approval from the MassDEP prior to starting construction.

The MassDEP's air permit provisions specify the contents of the application document that includes detailed descriptions of the emissions source, the predicted maximum emission rates, the measures used to control emissions and noise, and the resulting impacts to ambient air quality. The permitting process will assure that the Project is thoroughly reviewed by trained professionals in air quality control, charged with protecting health and the environment.

As noted, the MassDEP's regulations specify that all projects are required to implement BACT to minimize air emissions. Section 5 contains the BACT Analysis conducted for the Facility. The MassDEP also requires a demonstration that the project will not cause or contribute to an exceedance of state or national ambient air quality standards. Section 6 details the air dispersion modeling analysis conducted for the Facility. The results of this analysis demonstrate that the maximum ambient air impacts resulting from the emissions from the Facility are below EPA's Significant Impact Levels (SILs), and will not cause or contribute to an exceedance of NAAQS or MAAQS. The MassDEP also requires all projects to demonstrate compliance with the state's noise policy. The MCPA submitted to MassDEP for the Facility includes an assessment of potential noise impacts that address the MassDEP Noise Policy.

4.1.2 Nonattainment New Source Review

The Facility's potential NO_x emissions, as presented in Table 6-3, exceed the major source threshold of 50 tons per year. The Facility is located in a moderate non-attainment area for ozone. Therefore, the Facility will be subject to review under the MassDEP's Non-attainment NSR program (310 CMR 7, Appendix A). The requirements of the NSR program applicable to the Facility are summarized below.

The Facility will implement LAER for the NO_x emissions from the combustion turbine to meet the NSR requirements. The Facility must meet each applicable emission limitation under the

Massachusetts State Implementation Plan (SIP) and each applicable emissions standard of performance under 40 CFR Part 60 (New Source Performance Standards). Section 4.2.1 details the NSPS requirements for the Facility. The Facility will not be a major source of hazardous air pollutants (HAPs), so it will not be subject to an emissions standard of performance under 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants).

The Facility must address the Reasonable Further Progress requirement of the NSR program. It requires that NO_x emission offsets from other sources be obtained by the Facility so that the total emissions from existing sources in the area, new or modified sources that are not major sources, and the proposed source will be sufficiently less than the total emissions from existing sources prior to the application to construct the proposed source. This requirement ensures reasonable further progress by the time operation commences. The Facility must obtain NO_x emission offsets from other sources within the Ozone Transport Region. The total annual NO_x emissions from the Facility must be offset by an equal or greater reduction in the actual emissions of NO_x from other sources. The ratio of total actual emission reductions to the increase in actual emissions must be at least 1.26:1 (a 1.2:1 offset ratio coupled with a 5% public benefit set aside). All offsets used must be federally enforceable.

WLDC has identified several sources with sufficient Massachusetts Emission Reduction Credits (ERCs), which are federally enforceable, to meet the NSR offset requirement for its NO_x emissions. WLDC will acquire Massachusetts ERCs from such a source in the required ratio to fully offset the Facility's NO_x emissions prior to receiving its Plan Approval from MassDEP.

The NSR program requires the completion of a source impact analysis to demonstrate that its NO_x emissions will not contribute to nonattainment in any other state, or interfere with compliance by any other state, with any NAAQS, and will not interfere with measures required to be included in the applicable implementation plan for any other state under a PSD program. The air dispersion modeling analysis conducted for the Facility, which makes the required compliance demonstrations, is detailed in Section 6.

4.1.3 Prevention of Significant Deterioration

The Facility's potential NO_x and CO emissions, as presented in Table 6-3, exceed the PSD applicability threshold of 100 tons per year. The Facility is located in an area that is in attainment for all pollutants except ozone. Therefore, the PSD regulations (40 CFR Part 52.21) apply to the Facility for all attainment pollutants with potential emissions above the Significance Emission Rates defined in the PSD regulations (NO_x, CO, PM, PM_{10}, $PM_{2.5}$ and H_2SO_4). Delegated authority for the PSD program is no longer retained by MassDEP and the US EPA currently implements the rules. The requirements of the PSD program applicable to the Facility are summarized below.

The PSD program requires the application of BACT for each regulated attainment NSR pollutant with potential emissions exceeding the defined significance levels. The BACT analysis for the Facility for these pollutants can be found in Section 5.

The PSD program requires a source impact analysis to demonstrate that allowable emission increases from the proposed source, in conjunction with all other applicable emissions increases or reductions would not cause or contribute to air pollution in violation of any NAAQS in any air quality control region, or any applicable maximum allowable increase over the existing background concentration in any area. An air dispersion analysis was conducted for the Facility, as described in Section 6. The results of this analysis demonstrated that the ambient air impacts from the Facility are below the Significant Impact Levels (SILs) and PSD increments established by the EPA.

The PSD rules require any application for a permit must contain an analysis of ambient air quality in the area that the source would affect for each pollutant that it would have the potential to omit in a significant amount. For pollutants for which there is no NAAQS, the analysis must contain such air quality monitoring data as the Administrator determines is necessary to assess ambient air quality for that pollutant in the area that the emissions of that pollutant would affect. For pollutants for which there is an NAAQS, the analysis must contain continuous air quality monitoring data gathered for the purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase. In general, the continuous air quality monitoring data that is required must be gathered over a period of at least one year representing at least the year preceding receipt of the application. However, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not less than four months), the required data must be gathered over at least that shorter period. Post-construction monitoring is to be conducted as the Administrator determines is necessary to determine the effect emissions from the stationary source may have on air quality in any area.

WLDC has completed the required source impact analysis, which is detailed in Section 6 of this application. This analysis demonstrated that the maximum ambient impacts predicted from the Facility are below their respective SILs and PSD increments. Compliance with NAAQS has been demonstrated using conservative monitoring data from representative monitoring stations located in the area. Because the predicted maximum ambient air impacts from the Facility have been shown to be insignificant, as defined by the EPA, the conservative nature of the background data used in the analysis, and long-standing historical EPA precedent for sources with insignificant impacts, WLDC formally requests from the EPA a waiver from the pre-construction and post-construction monitoring requirements of the PSD program.

The PSD rules also include provisions for additional impact analyses. It requires an analysis of the impairment to soil and vegetation that would occur as a result of the source. Section 6.12 of this application describes the analysis conducted to determine the impact of the Facility on soils and vegetation. The results of this analysis demonstrated that the impacts of the Project on soils and vegetation do not exceed the EPA's Sensitivity Screening Levels.

4.1.4 Acid Rain Permit

The combustion turbine will be designated as a Phase II New Affected Unit under the federal Acid Rain Program. The Acid Rain Program requires coal-fired utility boilers to meet specified NO_x emission limits and requires all affected units to establish a compliance account and hold allowances not less than the total annual emissions of SO_2 from the previous calendar year. Every emissions source affected by the Acid Rain Program must obtain a permit. The Acid Rain Permit specifies the monitoring, recordkeeping, and reporting requirements for each affected unit at an affected source.

WLDC will certify a designated representative, and submit a complete Acid Rain permit application to the EPA at least 24 months before commencing operation. WLDC will establish a compliance account and obtain allowances for its annual SO_2 emissions. WLDC will meet all of the applicable certification, monitoring, recordkeeping, and reporting requirements of the Acid Rain Program by the established compliance deadlines, in accordance with 40 CFR Parts 72 and 75.

4.2 Federal Emissions Control Requirements

4.2.1 New Source Performance Standards

The Facility will be subject to the Federal New Source Performance Standards (NSPS) for newly constructed emission sources. Stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour which commence construction after February 18, 2005, are subject to the emission standards and compliance schedules set forth in 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines." This subpart regulates the emissions of NO_X and SO_2 from applicable units, such as the turbine proposed for this Facility.

According to Table 1 of Subpart KKKK, the NO_x emission standard for a new turbine firing natural gas with a heat input at peak load greater than 850 MMBtu/hr is 15 ppm at 15 percent O_2. For a new turbine firing fuels other than natural gas, with a heat input at peak load greater than 850 MMBtu/hr, the Subpart KKKK, Table 1 NO_x emission standard is 42 ppm at 15 percent O_2. With proposed stack concentrations of 2 ppm at 15 percent O_2 while firing natural gas, and 5 ppm at 15 percent O_2 while firing ULSD fuel, the NO_X emissions from the proposed combustion turbine will comply with the NSPS natural gas emissions standards.

Continuous compliance with the NSPS NO_X emission standards will be demonstrated by the use of a certified continuous emissions monitoring system (CEMS) to be installed on the turbine stack. The NO_X CEMS will be certified, operated, and maintained in accordance with the applicable requirements of the NSPS and 40 CFR 60, Appendix B, Performance Specification 2, "Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources."

The NSPS emission standard for SO_2 is the same for all turbines regardless of size and fuel type. SO_2 emissions must not exceed 110 nanograms per joule (ng/J) or 0.9 pounds per megawatt-hour (lb/MWh) for turbines that are located in continental areas. The maximum SO_2 emission rates from the combustion turbine of approximately 0.012 lb/MWh while firing natural gas 0.013 lb/MWh while firing ULSD fuel complies with the NSPS for SO_2 emissions.

The NSPS also establishes a fuel sulfur content limit of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) for turbines that are located in continental areas. This is approximately equivalent to a fuel sulfur content of 0.05 percent by weight (500 parts per million). The combustion turbine will utilize pipeline natural gas with a sulfur content of less than 0.6 grains per 100 standard cubic feet (gr/100 scf) or approximately 15 ppm sulfur by weight, and ULSD fuel containing 15 ppm sulfur by weight. Both fuels meet the NSPS fuel sulfur content limit.

WLDC will demonstrate compliance with the Subpart KKKK SO_2 emission standard by conducting sulfur analyses on the natural gas and ULSD fuels in accordance with the requirements of the NSPS. WLDC will submit reports of excess emissions and monitor downtime in accordance with the NSPS. Excess emissions will be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Steam generating units with a maximum design heat input capacity of 100 MMBtu per hour or less, but greater than 10 MMBtu per hour that commence construction after June 9, 1989, are subject to the requirements set forth in 40 CFR 60, Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." The auxiliary boiler proposed for the Facility, with a maximum heat input rate of approximately 21 MMBtu/hr, meets these applicability criteria and is therefore subject to this NSPS.

The SO_2 and PM emission standards contained in Subpart Dc do not apply to affected units that fire natural gas, such as the proposed auxiliary boiler. To comply with Subpart Dc, an initial notification will be submitted, indicating the date of construction and startup, the boiler's design heat capacity, and the fuel to be fired. Records will be kept of the amount of fuel combusted by the boiler during each day of operation. These records will be maintained for a period of at least two years, to comply with the NSPS recordkeeping requirements.

Stationary compression-ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, that are manufactured after April 8, 2006, and are not fire pump engines, must meet the requirements of 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." Subpart IIII also applies to certified National Fire Protection Association (NFPA) fire pump engines that are manufactured after July 1, 2006, and commence construction after July 11, 2005. Both the emergency diesel engine/generator set and the diesel fire pump proposed for the Facility will be subject to this NSPS.

Owners and operators of 2007 model year or later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW and a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new non-road CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007. For new non-road CI engines with a model year after 2006 with a maximum engine power greater than 560 kW, the Tier 2 emission standards listed in 40 CFR 89.112, Table 1 apply. Fire pump engines must comply with the emission standards listed in Table 4 of the NSPS.

The diesel fuel fired by both the emergency generator and the fire pump must meet the requirements of 40 CFR 80.510(a), which limits the sulfur content to 500 ppm or less. Beginning October 1, 2010, the fuel requirements of 40 CFR 80.510(b) must be met, which limits fuel sulfur content to 15 ppm or less.

The emergency diesel engine/generator set to be selected for the Facility will be certified by the manufacturer to meet the applicable emissions standards set forth at 40 CFR 89.112, Table 1, for Tier 2 engines. The fire pump will be certified to meet the applicable emission standards set forth in Table 4of the regulation. The generator and fire pump will be installed, configured and operated according to the manufacturer's specifications. The diesel generator and the fire pump will each be equipped with a non-resettable hour meter. Maintenance checks and readiness testing will be limited to 100 hours per year and annual operations of the emergency generator and the fire pump will be limited to 300 hours. The diesel fuel fired by the generator and the fire pump will be certified to meet the fuel sulfur content limit at the time of use.

Records will be kept of the operation of the diesel generator and fire pump, and of all non-emergency service that are recorded by the non-resettable hour meters. An initial notification will not be required for the emergency generator or fire pump, nor will there be any additional record keeping or reporting required to comply with the NSPS.

4.2.2 National Emission Standards for Hazardous Air Pollutants

The US EPA has established National Emission Standards for Hazardous Air Pollutants (NESHAPS) for a variety of source categories. 40 CFR 63, Subpart YYYY, establishes national emission standards and operating limits for HAP emissions from stationary combustion turbines located at major sources of HAP emissions. A major source of HAP emissions is a facility with the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAPS at a rate of 25 tons or more per year. The proposed project does not exceed either of the HAP major source thresholds. The proposed Facility is not a major source of HAPS, and is therefore exempt from the requirements of Subpart YYYY.

4.3 State Emissions Control Requirements

4.3.1 MassDEP Industry Performance Standards

The MassDEP has established Industry Performance Standards (310 CMR 7.26) for specified source categories that establishes a permit by rule in lieu of a source specific Plan Approval. The regulations at 310 CMR 7.26(30) through (37) establish performance standards for boilers installed on or after September 14, 2001 with a heat input rating equal to or greater than 10 MMBtu per hour but less than 40 MMBtu per hour. Although the auxiliary boiler proposed for the Facility has a maximum heat input rating of approximately 21 MMBtu per hour, which falls within the applicability range of the Performance Standards, the regulations do not apply to units located at facilities required to obtain an Operating Permit. However, the proposed auxiliary boiler will be designed, installed and operated consistent with the requirements set forth in 310 CMR 7.26(30) through (37).

The auxiliary boiler will be operated in accordance with the manufacturer's standard operating and maintenance procedures and will be limited to no more than 1,100 hours per 12-month period firing natural gas only. A tune-up will be performed on the auxiliary boiler annually, including an inspection for proper operation, any other maintenance recommended by the manufacturer, and an efficiency test.

The stack height of the auxiliary boiler will be sufficient to assure adequate plume dispersion and prevention of ambient air quality impacts that exceed NAAQS, as discussed in Section 6 of this application. The stack will not be equipped with rain protection that restricts the vertical exhaust flow of the combustion gases as they are emitted. The auxiliary boiler will meet the natural gas emission limits listed in 310 CMR 7.26(33)(b). The visible emissions from the auxiliary boiler will not exceed 10% opacity at any time during boiler operation.

A recordkeeping system will be established and implemented onsite to document compliance. The records kept will include the dates of boiler installation and first operation, a monthly record of fuel type, additives, usage, and sulfur content, as certified by the fuel supplier, a written record of all tune-ups, including inspections, maintenance, and efficiency tests, and all purchase orders and invoices related to boiler combustion or emission rate. All records will be maintained up-to-date and readily available for MassDEP examination, for at least three calendar years.

The regulations at 310 CMR 7.26(40) through (44) apply to engines and combustion turbines installed on and after March 23, 2006 that are not subject to PSD or NANSR review. The combustion turbine proposed for the Project is subject to PSD and NANSR review, and therefore is not subject to the MassDEP Industry Performance Standards.

The regulations at 310 CMR 7.26(42) apply to emergency or standby engines, including engines used as mechanical power sources for water pumping activities, with a rated power output equal to or greater than 37 kW but less than 1 MW that are constructed after March 23, 2006. Although the applicability of the regulations does not extend to units subject to subject to Prevention of Significant Deterioration (40 CFR 52.21) or Non-attainment Review at 310 CMR 7.00, Appendix A., the proposed emergency generator and fire pump for the Facility will be designed and operated consistent with the requirements of 310 CMR 7.26(42). Both the emergency generator and fire pump will comply with the applicable EPA emission limitations for non-road engines (40 CFR 89) at the time of installation as well as the visible emission standards of 310 CMR 7.06(1)(a) and (b), for the first three years of operation.

The diesel fuel fired in the emergency generator and fire pump will meet the applicable EPA fuel sulfur limits established in 40 CFR 80. The emergency generator and fire pump will be limited in operation to no more than 300 hours during any rolling 12-month period. A non-resettable hour meter will be installed on each engine to monitor compliance.

The engines will be operated and maintained according to the manufacturers' recommended procedures. They will be constructed, located, operated and maintained to meet the noise requirements of 310 CMR 7.10. The exhaust stacks of the engines will be designed and configured to meet the stack height and emission dispersion requirements of 310 CMR 7.26(42)(d)(4). The minimum stack height for each engine will be ten feet or greater above the engine enclosure. A monthly log will be maintained on-site of the hours of operation of each engine in order to monitor compliance with the 12-month rolling period operating limit. The operating hour records, along with all manufacturer specifications and certifications, and all fuel sulfur content documentation, will be made available to the MassDEP upon request.

4.3.2 Regional Greenhouse Gas Initiative

Massachusetts has established the Carbon Dioxide Budget Trading Program (310 CMR 7.70) to implement the nine-state, regional agreement, the Regional Greenhouse Gas Initiative (RGGI) to reduce greenhouse gas emissions (GHG) from power plants. The agreement, which was signed by Massachusetts in January of 2007, establishes a market-based "cap-and-trade" auction system that requires major power plants to obtain allowances to cover the amount of their carbon emissions. The Massachusetts CO_2 Budget Trading Program creates a regulatory structure for incentives and penalties designed to reduce carbon emissions statewide.

The Facility is subject to this program because, when constructed, it will be a source with a unit serving an electricity generator with a nameplate capacity equal to or greater than 25 MWe. The Facility will be required to obtain approximately 1.3 million CO_2 allowances per year for its direct emissions. The Massachusetts state-wide CO_2 allocation is approximately 26 million tons. Based on the annual CO_2 emissions from currently operating RGGI sources, WLDC anticipates that there will be adequate allowances available for the Facility.

To satisfy the requirements of the CO_2 Budget Trading Program, WLDC will:

- Designate a CO_2 authorized account representative and submit a completed account certificate of representation to MassDEP.
- Submit to MassDEP a CO_2 budget emission control plan ("ECP") at least twelve months before commencing operation.
- Operate the facility in compliance with the approved ECP.
- Comply with the monitoring, certification, recordkeeping, and reporting requirements of 310 C.M.R. § 7.70(8).
- Hold allowances in an amount not less than the total CO_2 emissions for each three calendar year control period.
- Submit a compliance certification report to MassDEP by March 1st following each control period.

4.3.3 MEPA Greenhouse Gas Emissions Policy and Protocol

The Massachusetts Executive Office of Energy and Environmental Affairs (EOEEA) has established a Massachusetts Environmental Policy Act (MEPA) Greenhouse Gas Emissions Policy and Protocol, which requires specified projects undergoing review by the MEPA Office to quantify their greenhouse gas (GHG) emissions and identify measures to avoid, minimize, or mitigate those emissions. The purpose of this Policy is to ensure that project proponents and reviewers carefully consider their potential GHG impact, and that all feasible measures are utilized to minimize those impacts.

The Policy applies to new projects that file an Environmental Notification Form (ENF) for MEPA review after October 15, 2007, the effective date of the policy. A Project is subject to the Policy if an EIR is required, and it falls into at least one of the following categories:

- MEPA has full scope jurisdiction or equivalent full scope jurisdiction over the project;
- The Project is privately funded and requires an Air Quality Permit from MassDEP;
- The Project is privately funded and requires a Vehicular Access Permit from the Mass Highway Department.

The GHG Policy is focused on emissions of CO_2, because it is the predominant contributor to global warming, and there is readily accessible data for calculating emissions. The following are the proscribed steps for the GHG analysis required by the Policy:

- Establish a Project Baseline – including direct emissions from stationary sources, indirect emissions from energy consumption and transportation, and any other potential sources.
- Alternatives Analysis – compare the GHG emissions associated with the preferred alternative with a code-compliant baseline and with project alternatives with greater GHG emissions-related mitigation.
- Mitigation – propose and evaluate direct measures for the proposed alternative to avoid, minimize, or mitigate damage to the environment to the maximum extent feasible.
- Offsets – propose off-site mitigation measures that have local or regional benefits. These offsets must be real, additional, verifiable, permanent, and enforceable in accordance with state law and Policy. All offsets consisting of monetary contributions require verification that the funds are directly responsible for GHG emission reductions.

WLDC submitted an ENF to MEPA for the Facility on November 30, 2007. MEPA issued an ENF Certificate for the Facility on January 23, 2008, which outlined the specific requirements for the Facility to comply with the GHG Policy. The Certificate directed WLDC to calculate and compare the GHG emissions associated with the Preferred Alternative with an alternative incorporating renewable fuels and/or technologies, and project alternatives with greater GHG emissions-related mitigation.

WLDC submitted a Draft Environmental Impact Report (DEIR) to MEPA for the Facility on August 15, 2008. The DEIR included a project GHG emissions baseline consisting of the direct CO_2 emissions from stationary sources, as well as the indirect CO_2 emissions from mobile sources associated with the operation of the Facility. The DEIR also included an alternatives analysis which compared the GHG emissions associated with the project baseline with other combustion technology and fueling alternatives for the Facility. The DEIR also included a commitment from WLDC to implement several of the design mitigation measures recommended by the MEPA GHG Policy.

MEPA issued a Certificate on the DEIR for the Facility on October 17, 2008, which included recommendations on revisions to the GHG analysis for the Facility, which will be presented in WLDC's Final Environmental Impact Report (FEIR), based upon the guidance of the MassDEP comment letter on the DEIR. The DEIR Certificate included the following recommendations for the Facility GHG analysis to fully comply with the MEPA Policy:

- The FEIR should commit to the building design and operations GHG mitigation measures presented in the DEIR and quantify the GHG reductions associated with these measures even if the reductions are relatively insignificant in comparison to stack emissions.
- The FEIR should include an expanded discussion of the role biofuels may play in the operation of the Facility, the potential technical challenges associated with using bio-fuels on-site, and what would be necessary to overcome those challenges.
- The FEIR should demonstrate why the use of bio-fuel in the less fuel-consuming equipment, such as the auxiliary boiler, emergency generator, and fire pump, is not viable.
- The FEIR should make a future commitment to the use of bio-fuels at the Facility, contingent on adequate supply.
- The FEIR should include a plan that describes and quantifies the range of future on-site GHG mitigation measures, such as using renewable fuels or more advanced turbine systems, as well as off-site mitigation measures which support energy efficiency and conservation in the surrounding communities.
- The FEIR should identify near term and future mitigation commitments, and where those commitments may be contingent on future developments, identify those contingencies.

WLDC will file an FEIR with the EOEEA that fully addresses the recommendations regarding compliance with the MEPA GHG Policy contained in the DEIR Certificate for the Facility. The FEIR will include a commitment to specific design and operational GHG mitigation measures, and the GHG emission reductions associated with those measures will be quantified. The FEIR will include an expanded analysis on the potential technical challenges associated with the use of bio-fuels at the Facility, including the viability of using bio-fuels for the less fuel-consuming equipment, and a future commitment to the use of bio-fuels, contingent on adequate supply, where it is technologically feasible. The FEIR will also include a proposal for a range of near-term and future on-site and off-site commitments to mitigate GHG emissions and support local energy efficiency and conservation efforts, as well as any future developments these commitments may require.

4.3.4 Source Registration

The MassDEP Source Registration requirements (310 CMR 7.12) apply to all fuel utilization facilities that fire natural gas with a maximum energy input capacity equal to or greater than 10 MMBtu/hr. The Facility is subject to the annual Source Registration reporting requirements because its NO_x emissions will exceed 25 tons per year. WLDC will submit to the MassDEP a Source Registration, signed by the designated Responsible Official, by April 15th of each year. The Source Registration forms will be completed and submitted using the MassDEP's online electronic system, and will include all descriptions of all combustion equipment, facility operating hours and operating schedule, all fuels used, detailed emission estimates for all criteria and hazardous air pollutants emitted, a description of all air pollution control equipment, and a signed certification of accuracy. WLDC will retain copies of all Source Registration information for at least five years from the date of submittal.

5.0 BACT ANALYSIS

The PSD regulations specify that a new major stationary source apply Best Available Control Technology (BACT) for each regulated NSR pollutant that it would have the potential to emit in significant amounts. As shown in Table 6-3, the regulated NSR pollutants for which the Facility has the potential to emit above the PSD significance thresholds are NO_x, CO, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4. WLDC will apply BACT to the combustion turbine, auxiliary boiler, and stand-by engines for the emissions of these pollutants to satisfy the requirements of the PSD program.

The determination of BACT is made through a “top-down” analysis of potentially viable control technologies starting with the approach that provides the greatest level of emission control. Technologies that result in higher emissions can only be considered if the more efficient control technology evaluated is determined to be either technically or economically infeasible. BACT is defined by EPA in 40 CFR 52.21 as follows:

> “Best available control technology means an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology determination result in emissions in excess of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.”

Thus, a BACT analysis is an assessment of technical, environmental, and economic impacts of various emission control options. BACT review is a “top-down” method for determining the best available control technology. In general, a top-down approach requires that all available control technologies be ranked in descending order of control effectiveness. The control technology examined and recommended as the most effective is considered the most stringent technology or BACT, unless technical considerations, energy requirements or economic considerations justify that the top technology is not feasible or achievable.

The following steps are followed in this BACT top-down analysis:

Step 1 - Identify All Control Technologies

Step 2 - Eliminate Technologically Infeasible Options

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Step 4 - Cost Effectiveness Analysis

Step 5 - Select BACT

Control options are first evaluated for their technical feasibility. Options found to be technically feasible are ranked by control efficiency. In the event the most stringent level of control is ruled out due to cost, energy consumption, or environmental impacts, the next most stringent level of control is analyzed until BACT is determined. An analysis of other control technologies is not necessary if the technology proposed is the highest level of control found technically feasible.

To complete the BACT analysis for the combustion turbine at the Facility, control technologies demonstrated in practice for similar sources, and corresponding emission limits established by various state agencies and the EPA were reviewed. BACT determinations listed in the USEPA RACT/BACT/LAER Clearinghouse (RBLC), the South Coast Air Quality Management District BACT determinations, the California Air Resources Board's BACT Clearinghouse Database, and any available recently issued air permits were also reviewed. The review was limited to combustion turbines permitted since 2000 with an output greater than 200 MW fired on natural gas and/or distillate oil used in a combined-cycle power plant configuration. The information gathered from these sources was used in determining the proposed BACT emission levels. This control technology analysis demonstrates that the proposed combustion turbine emissions are consistent with recent BACT determinations for similar sources.

Table 5-1 is a summary of the BACT Determination for the combustion turbine. Appendix B contains a listing of the recent BACT determinations considered for this analysis. The following sections provide a discussion of the emission control techniques that were considered to control the emissions from the combustion turbine and the selected BACT proposal for each pollutant.

5.1 Oxides of Nitrogen (NO_x)

NO_x emissions contribute to ground-level ozone formation, stratospheric ozone depletion and acid rain. NO_x emissions from the combustion of fossil fuels are mainly formed by the following three mechanisms:

- Fuel-bound NOx; originated from fuel-bound nitrogen in the fuel
- Prompt NOx promptly formed at the flame front
- Thermal NO_x; created by high temperature and is the main form of NO_x production

Natural gas has negligible fuel-bound nitrogen. Virtually all of the NO_X formed from the combustion of natural gas is thermal. Distillate oil has low levels of fuel-bound nitrogen. Thermal NO_X is the primary source of NO_X formation for distillate oil-fired turbines.

Beyond the selection of low emitting fuels, several design and add-on technologies have been developed to minimize NO_x emissions. These methods are divided in two main categories:

In-combustor NO_x control, which reduces the formation of NO_x during the combustion process:

- Diluent Injection
- Dry Low-NOx Combustors
- Catalytic Combustion / XONON

Post-combustion NO_x control, which reduces the NO_x emissions in the flue gas stream:

- SCONOx
- SCR

The following sections further discuss and evaluate these methods as BACT for NO_x emissions.

5.1.1 Diluent Injection

Diluent injection (water injection) or wet controls involve injection of a small amount of water or steam into the immediate vicinity of the combustor burner flame. Instantaneous cooling reduces the NO_x formation in the combustion chamber. However water or steam injection also leads to combustor flame instability and potential increases in emissions of CO and hydrocarbons (HC) resulting from incomplete fuel combustion. When water is used, it must be treated to meet strict chemical balance, similar to boiler feedwater. The amount of water required can be greater than one-half of the fuel flow. This results in a heat rate penalty; however, the power output rises somewhat. The corrosive impacts of excessively high water injection on plant maintenance must be considered. Therefore, vendors recommend an optimum balance of water-to-fuel ratios to minimize impacts on plant maintenance while minimizing NO_x emissions.

This control technique is a well-demonstrated technology. It will be utilized for the Facility during ULSD firing for additional NO_x control.

5.1.2 Dry Low - NO_x Combustors

In conventional combustors fuel and air are introduced into the combustion chamber separately and mix in small, localized zones. This translates to more localized hot spots and higher NO_x production. In dry low-NO_x (DLN) burners, air and fuel are mixed before entering the combustor to provide more homogeneous charge combustion. To achieve low NO_x emission levels, the mixture of fuel and air should be near the lean flammability limit of the mixture. At reduced load conditions, lean premixed combustors switch to diffusion combustion mode to avoid combustion instability and excess CO emissions; this means uncontrolled NO_x emissions in this mode.

This control technique is a well-demonstrated technology. This technology will be utilized for the Facility.

5.1.3 Catalytic Combustion / XONON

In catalytic combustion or XONON, a catalyst bed is used to oxidize the lean air fuel mixture instead of burning it with a flame. This limits the combustion temperature and therefore the formation of NO_x.

Catalytic combustion (XONON) has not been applied commercially to combustion turbines of a similar power output as the one proposed for the Facility. Therefore, it is not technically feasible or demonstrated in practice for the Facility.

5.1.4 SCONOx

The SCONOx process oxidizes both CO and NO to CO_2 and NO_2, with subsequent absorption of NO_2 by a potassium carbonate (K_2CO_3) coated catalyst. The carbonate coating reacts with NO_2 to form KNO_3 and CO_2. The system continually regenerates one of the multiple sections of the catalyst bed using hydrogen gas, which reacts and forms carbonate, water, and nitrogen. A two-stage catalytic hydrogen gas generator is also part of this process. In the first stage, natural gas and air are reacted across an oxidation catalyst to form CO and H_2. Steam is then added and the gases are reacted across another catalyst forming CO_2 and more H_2. This mixture is then diluted to 4% using steam or another inert gas (due to its explosivity). The regeneration cycle must take place in an oxygen free environment, which requires isolation from the CT exhaust gases. This is performed using many sets of louvers and seals both upstream and downstream of each catalyst section; with each regeneration cycle only lasting three to five minutes.

SCONOx has not been applied commercially to combustion turbines of a similar power output as the one proposed for the Facility. Therefore, it is not technically feasible or demonstrated in practice for the Facility.

5.1.5 Selective Catalytic Reduction (SCR)

The SCR system is a method for converting NO_x generated from the CT to diatomic nitrogen and water by reacting with NH_3 in the presence of a catalyst. NH_3 is vaporized and injected in the flue gas upstream of the catalyst, which, when passing over the catalyst, results in the following dominant chemical reactions.

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

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

The operating temperature and the flue gas properties are critical to both the performance and life of the catalyst. In simple-cycle settings, modules of the catalyst are installed downstream of the gas turbine. The typical operational temperature range for base-metal catalysts is 600°F to 800°F. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts (1100ºF) may be used. The key technical and economic issues are the performance and life of the catalyst.

Environmental impacts associated with SCR are emissions and storage of NH_3 and catalyst disposal. Low levels of NH_3 slip are to be considered in assessment of environmental impacts. Throughout the life span of the catalyst, NH_3 slip is expected to be less than 2 ppm at 15 percent O_2 while firing natural gas and 6 ppm at 15 percent O_2 while firing ULSD. SCR can also result in some additional PM_{10} emissions in the form of ammonium bisulfate compounds, which typically increase as ammonia slip is reduced by adding catalyst. By balancing the allowable ammonia slip and the required catalyst necessary to achieve the required level of NOx control, the SCR system's contribution to the potential PM_{10} emissions of the proposed Facility is considered to be negligible.

This control technique is a well-demonstrated technology. This technology will be utilized for the Facility.

5.1.6 Prior BACT Determinations for NO_x

According to the RBLC, there are numerous similar projects that have been permitted since 2000 with a stack concentration of 2.0 ppmvd @ 15% O_2 while firing natural gas. This is the lowest permitted NOx concentration achieved while firing natural gas. It has been achieved by these facilities utilizing DLNC and SCR

There are several similar projects included in the RBLC database that have been permitted since 2000 with a stack concentration of 6.0 ppmvd @ 15% O_2 while firing distillate oil. The Kleen Energy Systems, LLC facility in Connecticut was recently permitted at 5.9 ppmvd while firing oil. However, this facility has not been constructed to demonstrate compliance with this limit. These facilities have utilized water injection and oxidation catalysts to achieve this permit limit.

In Massachusetts, the Fore River Station in Weymouth, a 750 MW combined-cycle facility that commenced operation in 2003, was permitted with NOx emission limits of 2 and 6 ppmvd @ 15% O2 while firing natural gas and distillate oil, respectively. The IDC Bellingham facility was permitted with a 1.5 ppm NO_x emission limit while firing natural gas. However, since this facility has not been constructed, this emission limit has not been demonstrated in practice to be achievable for a BACT determination.

Other recently permitted Massachusetts facilities with a NO_x emission limit of 2 ppm while firing natural gas include the Mirant Kendall Station in Cambridge (2003), the Sithe Mystic Station in Everett (2003), ANP Bellingham (2002), and ANP Blackstone (2001). The Mirant Kendall Station was also permitted at 6 ppm NO_x for oil firing. All of these facilities, which represent the most recent Massachusetts BACT determinations for NO_x while firing natural gas and distillate oil, and are in operation, utilize the same control technologies as the Facility.

5.1.7 BACT for NO_x

The Project will fire natural gas and ULSD, which are the lowest NO_x emitting fuels available for a combustion turbine. DLN combustion and SCR are the available control technologies with the highest control efficiencies for NO_X while firing natural gas. SCR and water injection are the available control technologies with the highest NO_X control efficiencies while firing distillate oil. $SCONO_X$ and catalytic combustion (XONON) are not considered technically feasible for turbines of this size. Therefore, BACT for NO_x is proposed based on the use of DLN combustion while firing natural gas, an SCR system, and water injection during ULSD firing. Consistent with recent national and Massachusetts determinations, the proposed BACT emission rates for NO_X are stack concentrations of 2 ppmvd @ 15% O_2 while firing natural gas, and 5 ppmvd @ 15% O_2 while firing ULSD fuel.

5.2 Sulfuric Acid (H_2SO_4)

Emissions of H_2SO_4 are formed from the oxidation of sulfur in the fuel. Given that flue gas desulfurization systems have not been applied to natural gas combustion turbines, the only means for controlling H_2SO_4 emissions from a combustion turbine is to limit the sulfur content of the fuel. The Facility will utilize natural gas and ULSD fuel, the fuels with the lowest sulfur content available for use by combustion turbines. The use of natural gas and ULSD fuel will result in maximum H_2SO_4 emission rates of 0.0019 lb/MMBtu while firing natural gas and 0.0018 lb/MMBtu while firing ULSD.

5.2.1 Prior BACT Determinations for H_2SO_4

There is limited availability of H_2SO_4 permit limits for combustion turbines. The identified H_2SO_4 permit limits while firing natural gas have ranged from 0.0003 to 0.0065 lb/MMBtu, depending on the assumed fuel sulfur content, while the only H_2SO_4 emission limit identified for an oil-fired turbine was 0.015 lb/MMBtu.

5.2.2 BACT for H_2SO_4

The use of natural gas fuel and ULSD fuel will serve as BACT for H_2SO_4. The proposed emission rates of SO_2 and H_2SO_4 while firing both natural gas and ULSD are consistent with recent BACT determinations for similar facilities.

5.3 Particulate Matter ($PM/PM_{10}/PM_{2.5}$)

PM from fuel combustion is formed from non-combustible constituents (ash) in the fuel, soot resulting from unburned hydrocarbons, and the formation of ammonium sulfates within the SCR. The type of fuel, the design and operation of the combustion turbine, and the SCR system design and operation will each impact the formation of PM emissions. All PM emitted from combustion turbines is typically less than 10 microns (PM_{10}) in diameter. Although logically a subset of PM_{10}, the emissions of fine particulate matter ($PM_{2.5}$) from the turbines have been conservatively assumed to be equal to the emissions of PM_{10}.

Due to the high temperatures and flow rates of the exhaust stream and low particulate concentrations in the exhaust, add-on particulate controls such as electrostatic precipitators, fabric filters or wet scrubbers have not been applied to combustion turbines. Such add-on controls for combustion turbines of the size of the facility's are not considered technically feasible or demonstrated in practice. Rather, particulate emission control is achieved at the source by efficiently burning low ash and low sulfur fuel.

The PM emissions from natural gas firing are considered to be negligible, and marginally significant for distillate-oil firing, providing the most stringent degree of particulate emissions control available for combustion turbines. The design and operation of the turbine and SCR system, along with the use of natural gas and ULSD fuel, will result in PM_{10} and $PM_{2.5}$ emission rates of 0.0040 lb/MMBtu of heat input to the turbine while firing natural gas and 0.014 lb/MMBtu while firing ULSD.

5.3.1 Prior BACT Determinations for PM/PM_{10}

According to the RBLC database, the lowest permitted PM/PM_{10} emission rate for a similar project firing natural gas was 0.0042 lb/MMBtu. The lowest permitted PM/PM_{10} emission rate for a similar project firing distillate oil was 0.020 lb/MMBtu. In Massachusetts, the lowest permitted PM/PM_{10} emission rates for similar projects firing natural gas were 0.005 lb/MMBtu for the Millennium facility and 0.006 lb/MMBtu for Mirant Kendall. The lowest permitted PM/PM_{10} emission rate for a similar project firing distillate oil was 0.01 lb/MMBtu for Mirant Kendall. The Fore River and Millennium projects were permitted at 0.05 lb/MMBtu for oil firing. However, these recent Massachusetts permit limits were only based on front-half particulates, not including condensibles.

5.3.2 BACT for PM/PM_{10}/$PM_{2.5}$

The use of natural gas as the primary fuel, and limited use of ULSD as the back-up fuel will serve as BACT for PM/PM_{10}/$PM_{2.5}$. Particulate emissions will also be controlled through proper combustion in the combustion turbine. The proposed emission rates of 0.0040 lb/MMBtu heat input firing natural gas and 0.014 lb/MMBtu while firing ULSD are consistent with recent BACT determinations, with consideration of the inclusion of the condensible fraction.

5.4 Carbon Monoxide (CO)

CO emissions are formed due to incomplete combustion of the fuel typically caused by insufficient residence time, temperature or oxygen to combine unburned carbon with oxygen at high temperatures. CO emissions are typically higher during transient and low load operating conditions. Control technologies used to minimize CO emissions include the use of clean burning fuels, state-of-the-art combustion technology, add-on oxidation catalyst systems, and establishing minimum load restrictions. An evaluation of combustion controls and oxidation catalysts are presented below.

5.4.1 Combustion Control

When considering combustion technology as a control measure for CO emissions, a balance must be achieved to maintain efficient combustion while minimizing the formation of NO_x emissions. There have been several combustor designs for power generation introduced by combustion turbine vendors within the past twenty years that have focused on improving maintenance, efficiency, and emissions. Until very recently, the “standard combustor” employed water or steam to lower the combustion temperature, which reduced thermal NO_x. The DLN technology uses a lean, premix combustion chamber where fuel is premixed with high excess air to lower the flame temperatures and NO_x emissions without water or steam injection.

This control technique is a well-demonstrated technology. It will be incorporated in the design for the combustion turbine to be installed at the Facility.

5.4.2 Oxidation Catalyst

CO oxidation catalysts are typically used on turbines to achieve control of CO emissions. The CO catalyst promotes the oxidation of CO to carbon dioxide (CO_2) and water as the emission stream passes through the catalyst bed. The oxidation process takes places spontaneously, without the requirement for introducing reactants. Oxidation catalysts typically achieve at least 90% control efficiency in combustion turbines.

The use of a CO oxidation catalyst provides the highest level of CO control available for a combustion turbine. The Facility will utilize a CO oxidation catalyst for the control of CO emissions from the combustion turbine.

5.4.3 Prior BACT Determinations for CO

There are several similar turbine projects in the RBLC database that have been permitted since 2000 that utilize an oxidation catalyst for CO control. There are multiple facilities with a permitted stack CO concentration of 2.0 ppmvd @ 15% O_2 while firing natural gas. The Kleen Energy Systems, LLC facility in Connecticut was recently permitted with a CO limit of 0.9 ppm. However, this facility has not been constructed to demonstrate compliance with this limit.

The recently permitted oil-fired turbine projects listed in the RBLC have permitted stack CO concentrations ranging from 1.8 ppm to 15 ppm while firing distillate oil and utilizing oxidation catalyst technology. The Kleen Energy Systems, LLC facility in Connecticut was recently permitted with a CO limit of 1.8 ppm, and the Caithness Bellport, LLC facility was recently permitted with a CO limit of 2.0 ppm while firing oil. However, these facilities have not been constructed to demonstrate compliance with these limits. The PSEG Linden Generating Station was permitted in 2001 with a LAER CO emission limit of 4 ppm. The remaining BACT determinations for CO listed in the RBLC while firing oil ranged from 10 to 38 ppm.

In Massachusetts, the Mirant Kendall, Fore River, and Mystic facilities were most recently permitted with a 2 ppm CO limit while firing natural gas. The Mirant and Fore River facilities were also permitted with a 6 ppm CO limit while firing oil. These facilities all utilize oxidation catalyst for CO control.

5.4.4 BACT for CO

The use of combustion controls and a CO oxidation catalyst provides the highest level of CO control available for a combustion turbine. The Facility will utilize combustion controls and a CO oxidation catalyst for the control of CO emissions from the combustion turbine. Consistent with recent national and Massachusetts BACT determinations, the Facility will maintain a CO stack concentration of no more than 2 ppm at 15 percent O_2 while firing natural gas and 6 ppm at 15 percent O_2 while firing ULSD, at operating loads of 60% or higher.

5.5 Auxiliary Boiler

The auxiliary boiler will be rated at 21 MMBtu per hour and will fire natural gas only. Operation of the unit will be limited to the equivalent annual fuel use of 1,100 hours at the maximum firing rate.

There are no add-on emissions controls that have been demonstrated in practice for small, limited use, natural gas fired boilers similar to the Facility's auxiliary boiler. Emissions will be controlled through the use of clean burning natural gas, state-of-the-art combustion controls, and limitations on annual operation. The proposed unit will comply with the emissions limits established by MassDEP's Industrial Performance Standards; stringent emissions limitations developed to meet BACT requirements.

5.6 Stand-By Engines

Both the emergency generator and the diesel powered emergency fire pump will fire ULSD fuel and will be limited to no more than 300 hours of operation per year.

There are no add-on emissions controls that have been demonstrated in practice for small, limited use, LSD fired reciprocating engines similar to the Facility's emergency generator and the diesel powered emergency fire pump. Emissions will be controlled through the use of clean burning ULSD fuel oil with a sulfur content of 15 parts per million or less, state-of-the-art combustion controls, and limitations on annual operation. The units will typically operate no more than one hour per week for maintenance and reliability testing, except in the case of an emergency. The proposed units will comply with the applicable EPA non-road engine standard emissions limits at the time of installation; stringent emissions limitations developed to meet BACT requirements.

5.7 Cooling Tower

Particulate emissions from the Facility's wet cooling tower result from suspended solids contained in water droplets that drift from the tower exhaust. These emissions will be minimized through the use of water naturally low in solids content and the use high efficiency drift eliminators.

Water supplied to the tower will come from the Tighe-Carmody Reservoir. Sampling and analysis have shown that water from the Reservoir contains very low levels of suspended solids; less than 5 parts per million. Even with 10 cycles of water recirculation through the tower, a measure intended to minimize raw water use, the resulting solids in the water droplet drift from the tower is expected to be less than 50 parts per million. In addition to the very clean water supply, the tower will utilize high efficiency drift eliminators designed to minimize water droplet drift in the tower exhaust to less than 0.0005% of the total recirculating water rate. These combined measures will control particulate emissions from the tower to 0.01 pounds per hour and constitute BACT.

6.0 AIR DISPERSION MODELING ANALYSIS

This section presents the results of the air dispersion modeling analysis conducted for the Facility. The EPA has established NAAQS to protect human health and the environment, including the most sensitive of the population such as those with asthma or other respiratory ailments, with a margin of safety. The MassDEP has adopted the NAAQS and requires new energy generating facilities to demonstrate that their emissions will not exceed those standards. This determination is made through an ambient air quality impact analysis using US EPA and MassDEP approved air dispersion modeling methodologies.

This ambient air quality impact analysis has been conducted to demonstrate that the Project will result in air quality impacts that are not only below the NAAQS, but also below the Significant Impact Levels (SILs) which have been established by the EPA in the PSD Regulations for all of the criteria pollutants except for $PM_{2.5}$. Although not yet promulgated by either the EPA or MassDEP through rulemaking, the MassDEP has adopted a draft policy of applying the $PM_{2.5}$ SILs recommended by the Northeast States for Coordinated Air Use Management (NESCAUM). The $PM_{2.5}$ SILs recommended by NESCAUM were used to evaluate the modeling results for the Facility.

6.1 Source Emissions and Stack Data

Table 6-1 presents the exhaust gas characteristics of the turbine at various operating loads and ambient temperatures, along with the height, diameter, cross-sectional area, base elevation, and UTM coordinates of the turbine stack. Exhaust parameters are presented for operation of the turbine on both natural gas and ULSD fuel over the range of anticipated operating loads (60%, 75% and 100% of full load) and ambient temperatures (10°F, 59°F, and 90°F). Exhaust characteristics for the auxiliary boiler at three load conditions (60%, 80% and 100% of full load) and at full load operation for both the diesel generator and fire pump, along with the height, diameter, stack cross-sectional area, base elevation, and UTM coordinates for each source stack, are presented in Table 6-2.

Table 6-3 presents the potential emissions from the Project under normal operating conditions. Potential annual emissions are based on full load, year round operation of the turbine (average temperature of 59°F) on natural gas, with up to 1,440 hours per year of operation on ULSD fuel (average temperature of 10ºF), as well as emissions during periods of startup and shutdown. The potential emissions from the auxiliary boiler, diesel generator and fire pump are based on full load operation for 1,100, 300 and 300 hours per year, respectively.

6.2 Dispersion Environment

Land use within a three-kilometer radius of the Facility was classified in accordance with the Massachusetts Department of Environmental Protection (MassDEP) recommended method (Auer, 1978). This classification is necessary to determine if the modeled source is urban or rural. Urban sources require additional inputs to AERMOD. Information contained on USGS topographic maps was sufficient to determine that the area within three kilometers of the Facility is predominantly rural.

6.3 Good Engineering Practice (GEP) Stack Height Determination

US EPA regulations establish limitations on the stack height that may be used in dispersion modeling to calculate air quality impacts of a source for regulatory purposes. Each source must be modeled at its actual physical height unless that height exceeds its calculated Good Engineering Practice (GEP) stack height. If the physical stack height is less than the GEP formula height, the actual stack height is input to the model and the potential for the plume to be affected by aerodynamic wakes created by nearby buildings must be evaluated in the dispersion modeling analysis.

A GEP stack height analysis was performed in accordance with the procedures set forth in the US EPA guidance document "Guideline for Determination of Good Engineering Practice Stack Height" (US EPA, 1985). A GEP stack height, as measured from the base elevation of the stack, is defined as the greater of 65 meters (213 feet) or the formula height (Hg) determined from the following equation:

$$H_g = H + 1.5L$$

Where:

H = height of the nearby structure which maximizes H_g
L = lesser dimension (height or projected width) of the building

The GEP formula height is based on the dimensions of buildings "nearby" the stack that result in the greatest justifiable height. For the purposes of determining the maximum GEP formula height, "nearby" is limited to the less of five building heights or widths from the trailing edge of the building (edge closest to the source).

The Facility will have a single building that has three tiers which house: 1) the control center and support operations (auxiliary boiler, emergency generator and maintenance shop), 2) the heat recovery steam generator, and 3) the combustion and steam turbines. The height and projected width of the building tiers used for the GEP analysis are shown in Table 6-4. The tiers are listed in descending order relative to the resulting formula GEP heights. The building tier that houses the heat recovery steam generator (HRSG) is the controlling structure for all sources. The HRSG tier is a squat structure, 115 feet (35.1 meters) high, 120 feet (36.6 meters) wide and 130 feet (39.6 meters) long. The resulting GEP formula height is 287.5 feet (87.6 meters).

Since none of the proposed stack heights exceed the GEP height, assessment of building downwash in the modeling analysis is required.

6.4 Cavity Region

Buildings located near to stacks can create cavity regions which can trap the stack's emissions and result in locally high concentrations of air contaminants. The cavity region created by a building can extend out to three times the lesser of a building's height or its projected width. The cavity height can extend up to the structure height plus one-half the lesser of the structure height or projected width. Air quality impacts with the downwind cavity regions need to be analyzed when a stack's height is less than the cavity height.

As shown in Table 6-5, the HRSG building tier results in the highest cavity height and greatest cavity region extent. The cavity region created by the 115 foot tall HRSG building tier extends 345 feet from the structure and 172.5 feet above the ground. The closest fence line to the HRSG building is approximately 140 feet to the north. The cavity region from the 115-foot tier has the potential to extend beyond the fence line and, therefore, is located in ambient air. Even though the turbine stack is above the calculated cavity height, cavity impacts were included in the modeling analysis in order to assure a complete assessment.

6.5 Local Topography

Local topography plays a role in the selection of an appropriate dispersion model. Dispersion models can be divided into two categories: (1) those applicable to areas where terrain is less than the height of the top of the stack (simple terrain), and (2) those applicable to areas where terrain is greater than the height of the top of the stack (complex terrain). Terrain in the immediate area of the Facility is relatively flat. The closest complex terrain for the turbine stack is found approximately 3,000 meters from the turbine stack.

6.6 Models Selected for Use

The dispersion environment, potential of aerodynamic building downwash effects on ground-level concentrations, and the local topography help to determine the appropriate models for use in a dispersion modeling analysis. Simple terrain models are used to calculate concentrations in simple terrain (below stack-top elevation) and intermediate terrain (up to plume height). Complex terrain models are used to calculate concentrations in complex terrain (above stack-top elevation).

Based on stack heights that are less than the GEP formula height and terrain above the stack top elevation within eight kilometers of the stacks, preliminary screening modeling is performed with EPA's SCREEN3 (dated 96043) model. If the results of the conservative SCREEN3 model do not predict compliance with applicable standards and additional modeling is necessary, the preferred model is the EPA AERMOD model for both simple and complex terrain.

SCREEN3 can be applied to predict 1-hour, ground-level calculations for single sources. The model incorporates the effects of building downwash in both the cavity and wake regions (areas of plume downwash beyond the cavity region). The SCREEN3 model calculates 1-hour concentrations in simple terrain using algorithms from the US EPA Industrial Source Complex model, ISCST3. For complex terrain elevations, the SCREEN3 model calculates a 24-hour concentration using the VALLEY model. The VALLEY model concentrations are based on six hours of persistent meteorological conditions, and allow the plume to come no closer than 10 meters to the ground. The SCREEN3 model also makes an ISCST3 calculation for intermediate terrain receptors. Intermediate terrain receptors have elevations that are greater than stack-top elevation but less than plume height. The higher of the VALLEY and ISCST3 calculations is used in the screening results.

As discussed further below, following application of the SCREEN3 model, the US EPA AERMOD model was used as a refined tool to evaluate any pollutants and averaging periods for which SCREEN3 modeling yielded results above the Significant Impact Levels. AERMOD was used to estimate maximum 1-hour average ground-level concentrations at all receptor locations, including offsite locations within the cavity region. AERMOD is a refined model that can be applied to consider actual meteorological in the project area and the potential building downwash effects on ground-level concentrations and to estimate concentrations in either simple or complex terrain.

6.7 Preliminary Screening Model Application

The SCREEN3 dispersion model was applied in accordance with the recommendations made in EPA's "Guideline on Air Quality Models" (EPA, 1986) to assess the magnitude of maximum pollutant concentrations from the combustion turbine over a range of operating loads and ambient temperatures. SCREEN3 was applied using rural dispersion parameters, default meteorology, building downwash and terrain elevations. The model was applied for the full set of 54 default meteorological conditions that accompany the model and encompass all atmospheric stability classes and a range of wind speeds. The stability class and wind speed combinations used for the SCREEN3 modeling are presented in Table 6-6. Default mixing heights are dependent upon the wind speed. The SCREEN3 wind speed/mixing height combinations are presented in Table 6-7. Table 6-8 presents the distances and terrain elevations used in the SCREEN3 simple terrain analysis.

Simple terrain screening receptors were located along a single radial. Receptors were placed at 100-meter spacing out to 2 kilometers, 200-meter spacing out to 4 kilometers, 500-meter spacing out to 10 kilometers and 1 kilometer spacing out to 20 kilometers. An additional receptor was located at 106 meters. This represents the closest distance beyond the potential cavity region, based on three times the controlling building height (35.1 meters). The distance to the closest fenceline (approximately 140 feet) falls inside of the potential cavity region.

Receptor elevations reflect the maximum terrain height found for a given distance, over all compass directions. The closest complex terrain receptor is located 3.0 kilometers from the facility. For the simple terrain screening analysis, the stack-top elevation was assigned as the receptor elevation for all distances beyond 3 kilometers. SCREEN3 receptor terrain height values are based on the difference between the actual terrain elevation and the stack base elevation (240 feet mean sea level).

Table 6-9 presents the terrain elevations and distances used in the SCREEN3 complex terrain screening analysis and determined using the Digital Elevation Model (DEM), as discussed further below. The complex terrain receptors were based on the closest distance to the turbine stack for which elevations ranging from stack-top to the maximum elevation found within 20 kilometers. The closest complex terrain is found approximately 3.0 kilometers from the facility, with elevations extending to 415 meters (1,360 feet) above stack-base elevation at 20 kilometers.

The SCREEN3 model calculates one-hour concentrations at simple terrain locations. The model calculates 24-hour concentrations in complex terrain. The VALLEY complex terrain concentrations are based on six hours of persistent meteorological conditions.

NAAQS have been established for various averaging periods. Short-term 1-hour and 8-hour standards have been established for carbon monoxide. An annual standard has been established for nitrogen dioxide. Annual, 3-hour, and 24-hour standards have been established for sulfur dioxide. Annual and 24-hour standards have been established for particulate matter. To estimate concentrations for each averaging period, scaling factors of 0.9, 0.7, 0.4, and 0.08 were applied to the 1-hour averages predicted by the SCREEN3 model to derive 3-hour, 8-hour, 24-hour, and annual average estimates.

The 24-hour average complex terrain results were first scaled to one-hour concentrations using a scaling factor of 4.0. The same scaling factors described above were then applied to the 1-hour estimates to obtain estimates for averaging periods other than the 24-hour average.

A simple terrain screening modeling analysis, a complex terrain screening modeling analysis and a cavity screening analysis were performed using the SCREEN3 model for the flue gas characteristics of the proposed turbine at ambient temperatures of 10°F, 59°F, and 90°F at 60%, 75% and 100% of the design capacity for both natural gas and ULSD. The auxiliary boiler was modeled for 60%, 80% and 100% of full load. The emergency generator and fire pump were also evaluated with SCREEN3 at full load. Screening modeling was performed to determine the worst-case short-term and long-term operating conditions for each modeled pollutant.

Table 6-10 presents the impact concentrations predicted by the SCREEN3 model for each modeled load condition and ambient temperature for the combustion turbine on natural gas fuel. Table 6-11 presents the predicted impact concentrations for each modeled load condition and ambient temperature for the combustion turbine on ULSD fuel. The predicted impact concentrations from the auxiliary boiler, emergency generator and fire pump are presented in Table 6-12. In each instance, the actual 1-hour average impacts predicted for each pollutant were determined by scaling the unit emission rate (i.e. 1 gram per second) normalized 1-hour concentrations by the maximum equipment emission rates presented in the tables. To estimate concentrations for other averaging periods, the scaling factors discussed above were applied to the one-hour averages, along with any applicable operating limitations.

The values presented in Tables 6-10 through 6-12 reflect the following annual operating limits for the sources:

- Turbine operations with natural gas will be unrestricted.
- Turbine operations with ULSD will be limited to 1,440 hours per year.
- The auxiliary boiler will be limited to 1,100 hours per year.
- Both the emergency generator and fire pump will be limited to 300 hours per year.

Short-term averages (24 hours and less) are based on the potential that each source could be operating for the entire averaging period. Other than one hour per week for maintenance testing, the diesel generator and fire pump will not operate concurrently with the turbine.

As shown in Tables 6-10, 6-11, and 6-12, the SCREEN3 model calculated potential cavity impacts from the auxiliary boiler (at all three operating loads), emergency generator and fire pump and from the turbine only when operating at 60% load at 59ºF and at 90ºF.

Table 6-13 presents a summary of the maximum, modeled SCREEN3 pollutant concentrations presented in Tables 6-10, 6-11, and 6-12 from each of the modeled sources. As determined from a review of the results provided in Tables 6-10 and 6-11, the maximum turbine impact concentrations result from full load operation at 59°F on both natural gas and ULSD, when the plume could potentially be entrapped within the cavity region created by the HRSG building tier. Beyond the cavity region, impacts are greater in simple terrain than complex terrain for all modeled operating scenarios and fuels. The maximum short-term impacts while firing natural gas are at 100% load at 10°F. The maximum annual impacts while firing natural gas are at 100% load. The maximum impacts while firing ULSD are at full load at 59ºF.

Annual impact concentrations for the individual sources are based on the annual operating limits: 1,440 hours for ULSD for the turbine, 1,100 hours for the auxiliary boiler, and 300 hours for both the emergency generator and fire pump. These operating limits were used to determine the annual average emission rate for each pollutant from each source, which was then applied to the unit emission rate impacts to predict the annual average pollutant impacts. The total annual impact concentrations shown in Table 6-13 are based on the sum of the maximum values for the gas-fired turbine at 59°F, the ULSD-fired turbine, the auxiliary boiler, emergency generator and fire pump.

Short-term averages (24 hours and less) are based on the potential that each source could be operating for the entire averaging period. Other than one hour per week for maintenance testing, the diesel generator and fire pump will not operate concurrently with the turbine. The total short-term concentrations shown in Table 6-13 are based on the sum of the maximum values for the turbine and auxiliary boiler, and the 1-hour average impacts from both the emergency generator and fire pump during maintenance testing. The total estimates are conservative in that all sources were assumed to have maximum impacts at the same location and with the same meteorological conditions.

The individual source and potential total concentrations are compared to the SILs in Table 6-13. As shown in the table, screening values are greater than the SILs for:

- Annual NO_2 ,
- 3-hour, 24-hour and annual SO_2, and
- 24-hour and annual PM_{10} and $PM_{2.5}$.

Based on the results of the SCREEN3 modeling, refined modeling was performed to demonstrate the emissions associated with this Facility would result in impacts that are less than the SILs.

6.9 Preliminary Refined Modeling for Significant Impact Areas

A preliminary refined AERMOD modeling analysis was performed to determine the significant impact area of the proposed project.

Five years of hourly meteorological data were processed with AERMET for input to the AERMOD model to assess simple and complex terrain concentrations. Surface observations from Westover Air Force Base in Chicopee, Massachusetts, for 1991 through 1995 were used with concurrent upper air data from Albany, New York. Preprocessed, AERMOD-ready data sets were obtained from MassDEP. A polar grid was centered at the proposed turbine stack. Radials were placed from 0 degrees to 350 degrees at ten-degree increments. Maximum simple terrain screening values were predicted to within 400 meters of the turbine stack. Maximum complex terrain values were predicted to occur at 4620 meters. The receptor grid was established to assure that these areas of maximum impact as determined from the SCREEN3 modeling were sufficiently covered in the refined modeling. Receptor rings were located at

- 50-meter increments out to 250 meters,
- 100-meter increments out to two kilometers,
- 200-meter increments out to four kilometers, and
- 500-meter increments out to 10 kilometers.

Fenced, on-site locations were not included in the analysis, as these locations are not accessible to the general public and, therefore, are not considered ambient air.

The maximum terrain elevation and hill height was assigned for each receptor through the application of AERMAP. Digital Elevation Model (DEM) data for the following USGS quadrangles were input to AERMAP:

- Easthampton, MA
- Mount Holyoke, MA
- Mount Tom, MA
- Southwick, MA
- Springfield, North, MA
- Springfield, South, MA
- Westhampton, MA
- West Springfield, MA, and
- Woronco, MA.

Each source was modeled individually with a 1.0 gram per second emission rate. As was done with the SCREEN3 results, individual source pollutant concentrations were determined by multiplying the source emission rate for the applicable averaging period by the modeled unit emission rate impact. Refined concentrations from the individual sources were initially evaluated to examine potential cavity impacts.

Annual impact concentrations for the individual sources are based on the annual operating limits; 1,440 hours for ULSD for the turbine, 1,100 hours for the auxiliary boiler, and 300 hours for both the emergency generator and fire pump. The annual total concentrations are based on the sum of the maximum values for the gas-fired turbine at 59°F, the ULSD-fired turbine, the auxiliary boiler, emergency generator and fire pump.

Short-term averages (24 hours and less) are based on the potential that each source could be operating for the entire averaging period. Other than one hour per week for maintenance testing, the diesel generator and fire pump will not operate concurrently with the turbine. The total short-term concentrations were based on the sum of the maximum values for the turbine, auxiliary boiler and one hour from both the emergency generator and fire pump.

The individual source and potential total concentrations are presented in Table 6-14 and compared to the SILs. As shown in the table, the total impact concentrations were all below SILs except for 24-hour $PM_{2.5}$.

The total estimates are conservative in that all sources were assumed to have maximum impacts at the same location and time.

Pollutant specific refined modeling was performed to demonstrate that the 24-hr $PM_{2.5}$ impacts from the Facility are less than the SIL. Based on the conservative assumption that the maximum impacts from all of the modeled sources occur at the same location, the maximum combined modeled annual NO_2 impact concentration value was below the SIL. In order to be conservative, annual NO_2 impacts were also included in the pollutant specific refined modeling analysis. The refined modeling determines the predicted maximum cumulative impacts of the Facility's sources.

Annual NO_2 impacts were evaluated for:

- Unrestricted gas-fired turbine operations at 60% and full load, 59°F,
- ULSD-fired turbine operations at full load, 59°F, for 1440 hours,
- Auxiliary boiler operating at full load for 1,100 hours,
- Emergency generator operating for 300 hours, and
- Fire pump operating for 300 hours.

The 24-hour $PM_{2.5}$ impacts were evaluated for:

- ULSD-fired turbine operations at 60% and full load, 59°F,
- Auxiliary boiler at full load,
- Emergency generator operating for 1 hour, and
- Fire pump operating for 1 hour.

Other than one hour per week for maintenance testing, the diesel generator and fire pump will not operate concurrently with the turbine. The emergency generator and the fire pump were modeled separately from the turbine and auxiliary boiler to determine their maximum 1-hour impacts over the five-year modeling period. The 24-hour impact from maintenance testing of these two sources was calculated from the maximum 1-hour impact with twenty-three hours of no impact. This value was added to the 24-hour concentrations from the turbine and auxiliary boiler.

Table 6-15 presents the AERMOD modeling results in comparison to the Significant Impact Levels (SILs). As shown in Table 6-15, the maximum annual NO_2 impact predicted by the pollutant specific refined modeling is below the SIL. The maximum 24-hour $PM_{2.5}$ concentrations predicted by the pollutant specific refined modeling exceed the SIL in both 1991 and 1995, and are 98% of the SIL in 1994. However, these concentrations are based on the conservative assumption that the maximum impacts resulting from the maintenance testing on the emergency generator and the fire pump occur at the same location as the maximum impacts from the combustion turbine and the auxiliary boiler. Table 6-16 shows the modeled time periods where the combined impacts from all sources exceeded the SIL and the one value in 1994 that is 98% of the SIL, and the locations where those impacts occurred. As shown in Table 6-16, the maximum impacts from the combustion turbine and auxiliary boiler were actually predicted to occur at different time periods and locations than the maximum impacts from the emergency generator and fire pump.

Table 6-17 shows the predicted impacts from the emergency generator and fire pump at the same locations where the maximum predicted impacts from the combustion turbine and auxiliary boiler were predicted, as shown in Table 6-16. As shown in Table 6-17, the maximum predicted impacts from the emergency generator and fire pump at those locations occur during different time periods. The combined maximum 24-hour $PM_{2.5}$ impact concentrations from the combustion turbine, auxiliary boiler, emergency generator, and fire pump, at those locations are all below the SIL.

As shown in Tables 6-15 and 6-17, the results of the pollutant specific refined modeling demonstrate that the maximum predicted annual NO_2 and 24-hour $PM_{2.5}$ impacts from the Facility are below their respective SILs.

6.10 Background Air Quality

When conducting an air quality impact analysis with respect to NAAQS, the existing background air quality in the absence of the proposed source must be considered in combination with the impacts resulting from the proposed source. When background air quality data is not available for the project area, other representative background data from nearby monitoring stations must be used. As there are no ambient monitoring stations located in Westfield, the nearest monitoring stations, located in Chicopee and Springfield, were considered to represent the existing background air quality in the area of the Site.

The Chicopee and Springfield monitoring stations are located in close proximity to the Facility, so they are representative in terms of topography, climatology, and meteorology. The Chicopee monitoring station is located in a similar suburban setting as the Facility, not densely populated or trafficked, and thus is considered to be representative of the area. However, this station only includes NO_2 and $PM_{2.5}$ monitors. The Springfield monitoring stations, which together include monitors for all of the criteria pollutants, are located in a dense, downtown, high-traffic area. The background data from these monitors would be expected to be higher than values obtained in the less trafficked area of Westfield surrounding the Facility. Therefore, the use of the Springfield monitor background data is conservative.

Background concentration data for criteria pollutants during the most recent three years (2005-2007) were obtained from the EPA AirData website, http://www.epa.gov/air/data/index.html. The background values presented for the criteria pollutants were selected based on the nearest sampling sites in Chicopee (NO_2 and $PM_{2.5}$) and Springfield (CO, PM_{10}, and SO_2). The background data from the Springfield monitors used were the highest values measured during the three year period.

The individual monitor values selected and the background concentration values used in the analysis are presented in Table 6-18. The short-term CO, PM_{10}, and SO_2 background concentration values (1-hr, 3-hr, 8-hr and 24-hour) are the highest of the second-high monitor concentrations. The annual NO_2 and SO_2 background concentration values are the highest of the annual mean monitor values. The 24-hour $PM_{2.5}$ background concentration value is the 3-year average of the 98th percentile values. The annual $PM_{2.5}$ background concentration value is the 3-year average of the annual mean values.

NAAQS compliance has been demonstrated for the Project by comparing the total concentrations (i.e., modeled concentrations plus representative background concentrations) to the standards. The use of conservative background values from the Springfield monitors provides additional assurance that NAAQS compliance is being maintained with the development of the Facility.

6.11 Criteria Pollutant Modeling Results

Table 6-19 presents a summary of the maximum, modeled pollutant concentrations. Pollutant specific modeling was used to determine the maximum annual NO_2 and 24-hour $PM_{2.5}$ results. Where refined modeling based on individual source maxima was sufficient to demonstrate modeled concentrations that are less than the SILs, those results are also included. As shown in the table, the maximum modeled Facility impact concentrations and below the applicable SILs, and when combined with background concentrations from representative area monitoring stations, the cumulative predicted air quality concentrations are well below the applicable NAAQS.

Table 6-20 presents a comparison of the maximum modeled Facility impact concentrations in comparison with their respective PSD increments. Pollutant specific modeling was used to determine the maximum annual NO_2 and 24-hour $PM_{2.5}$ results. Where refined modeling based on individual source maxima was sufficient to demonstrate modeled concentrations that are less than the SILs, those results are also included. As shown in the table, the maximum modeled Facility impact concentrations are each well below their respective PSD increments.

6.12 Impacts to Vegetation and Soils

The results of the air dispersion modeling demonstrated that the emissions from the Facility will result in ambient air quality impacts below the EPA-established SILs. Therefore, the Facility will have an insignificant impact on existing air quality.

The PSD regulations require an air quality impact analysis on sensitive types of soils and vegetation. An assessment was performed by comparing the Facility's predicted worst case impacts, in combination with existing background air quality levels, to vegetation sensitivity screening levels presented in Table 3.1 of the EPA's "A Screening Procedure for the Impacts of Air Pollution on Plants, Soils and Animals" (EPA, 1980). The screening levels represent the minimum reported levels at which visible damage or growth effects to vegetation may occur. The following are the pollutant impact averaging periods which were included in this analysis for the Facility:

- 1-hour, 3-hour and annual SO_2,
- 4-hour, 8-hour, monthly and annual NO_2, and
- Weekly CO.

The AERMOD model was used to determine the maximum 3-hour and annual SO_2 impacts, the maximum annual NO_2 impacts, and the maximum 1-hour and 8-hour CO impacts. To determine the 1-hour SO_2 impact, a scaling factor of 1.11 was applied to the predicted 3-hour impact concentration. To determine the 4-hour, 8-hour, and 1-month NO_2 impacts, scaling factors of 11.25, 8.75, and 5.00 were applied to the maximum modeled annual impact concentration. A scaling factor of 0.4 was applied to the modeled 1-hour CO maximum impact concentration to determine the 1-week impact concentration. These scaling factors were all derived from EPA screen modeling guidance.

The background air quality concentrations used in the modeling analyses as discussed previously were used for this analysis as well. Short-term background values (24-hours and less) were based on the highest of the yearly second-high values. Background monitoring data is not available for all of the averaging periods considered in the vegetation screening analysis. In those cases, the next shortest averaging period was used to conservatively estimate the background. Background was conservatively estimated for:

- Use of 1-hour values for 4-hour, 8-hour and monthly NO_2; and
- Use of 8-hour values for weekly CO.

The results of the air quality impact analysis on sensitive types of soils and vegetation are presented on Table 6-21. As shown on Table 6-21, the total impact concentrations determined through modeling, when combined with existing background concentrations, do not exceed any of the Sensitivity Screening Levels listed. The results of this analysis demonstrate that the ambient air impacts from the proposed Facility will not adversely impact soils or vegetation.

6.13 References

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