APPENDIX A

EMISSION CALCULATIONS

Table A-1. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	183,700.0		159,200.0		142,500.0
Heat Rate (Btu/kwh)	10,070.0		10,320.0		10,650.0
Heat Input (mmBtu/hr)	1,849.9		1,642.9		1,517.6
Fuel Oil (lb/hr)	99,722.9		88,568.4		81,812.7
Fuel:					
Heat Content,LHV (Btu/lb)	18,550		18,550		18,550
CT Exhaust:					
Volume Flow (acfm)	2,450,287		2,288,314		2,190,589
Volume Flow (scfm)	851,152		773,514		728,816
Mass Flow (lb/hr)	3,743,000		3,390,000		3,189,000
Temperature (oF)	1,060		1,102		1,127
Moisture (% Vol.)	11.59		12.40		12.71
Oxygen (% Vol.)	10.96		10.95		11.03
Molecular Weight	28.25		28.15		28.10
Water Injected (lb/hr)	135,390		107,070		92,890
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,072,001		974,218		917,922
Temperature (oF)	205		205		205
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	70.2		63.8		60.1
Stack Height (ft)	180		180		180

Source: General Electric, 1992.

Table A-3. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	7.77E-03		6.90E-03		6.37E-03
	TPY	1.17E-03		1.04E-03		9.56E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	4.62E-03		4.11E-03		3.79E-03
	TPY	6.94E-04		6.16E-04		5.69E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	5.55E-03		4.93E-03		4.55E-03
	TPY	8.32E-04		7.39E-04		6.83E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	6.02E-02		5.35E-02		4.94E-02
	TPY	9.03E-03		8.02E-03		7.41E-03
Sulfuric Acid Mist	% of SO2	8		8		8
	lb/hr	1.22E+01		1.08E+01		1.00E+01
	TPY	1.83E+00		1.63E+00		1.50E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-2. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	17.0		17.0		17.0
lb/hr	17.0		17.0		17.0
TPY	2.6		2.6		2.6
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	99.72		88.57		81.81
TPY	15.0		13.3		12.3
Nitrogen Oxides					
Basis, ppm* (1)	42.0		42.0		42.0
lb/hr	326.2		290.2		268.0
TPY	48.9		43.5		40.2
Carbon Monoxide					
Basis, ppm+ (1)	30.0		30.0		30.0
lb/hr	98.4		88.6		83.2
TPY	14.8		13.3		12.5
VOCs (as methane)					
Basis, ppm+ (1)	4.0		3.9		4.1
lb/hr	7.50		6.58		6.50
TPY	1.1		1.0		1.0
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.65E-02		1.46E-02		1.35E-02
TPY	2.47E-03		2.19E-03		2.03E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) General Electric, 1992; (2) EPA, 1990

Table A-4. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	2.59E-02		2.30E-02		2.12E-02
	TPY	3.88E-03		3.45E-03		3.19E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	3.14E-01		2.79E-01		2.58E-01
	TPY	4.72E-02		4.19E-02		3.87E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.94E-02		1.73E-02		1.59E-02
	TPY	2.91E-03		2.59E-03		2.39E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	8.79E-02		7.80E-02		7.21E-02
	TPY	1.32E-02		1.17E-02		1.08E-02
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	5.18E-01		4.60E-01		4.25E-01
	TPY	7.77E-02		6.90E-02		6.37E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	1.29E-01		1.14E-01		1.05E-01
	TPY	1.93E-02		1.71E-02		1.58E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	4.33E-02		3.85E-02		3.55E-02
	TPY	6.50E-03		5.77E-03		5.33E-03
Polycyclic Organic Matter	lb/10E+12 Btu (1)	0.278		0.278		0.278
	lb/hr	5.14E-04		4.57E-04		4.22E-04
	TPY	7.71E-05		6.85E-05		6.33E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	7.49E-01		6.65E-01		6.15E-01
	TPY	1.12E-01		9.98E-02		9.22E-02
Carbon Dioxide	% Exhaust Gas	5.32		5.21		5.11
	lb/hr	3.10E+05		2.76E+05		2.55E+05
	TPY	4.65E+04		4.14E+04		3.83E+04

Source: (1) EPA, 1990

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	4.04E-02		3.59E-02		3.32E-02
	TPY	6.06E-03		5.38E-03		4.97E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	3.61E-02		3.21E-02		2.96E-02
	TPY	5.42E-03		4.81E-03		4.44E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.68E-02		1.49E-02		1.38E-02
	TPY	2.51E-03		2.23E-03		2.06E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	1.26E+00		1.12E+00		1.04E+00
	TPY	1.90E-01		1.68E-01		1.56E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	4.99E-02		4.43E-02		4.09E-02
	TPY	7.48E-03		6.64E-03		6.14E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	170,700.0	151,900.0	147,100.0	142,700.0	131,800.0
Heat Rate (Btu/kwh)	9,460.0	9,750.0	9,860.0	9,970.0	10,230.0
Heat Input (mmBtu/hr)	1,614.8	1,481.0	1,450.4	1,422.7	1,348.3
Natural Gas (lb/hr)	75,055.6	68,836.9	67,413.7	66,126.8	62,668.6
(cf/hr)	1,699,813	1,558,974	1,526,743	1,497,599	1,419,278
Fuel:					
Heat Content, LHV (Btu/lb)	21,515	21,515	21,515	21,515	21,515
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	2,354,349	2,239,805	2,212,530	2,188,744	2,123,643
Volume Flow (scfm)	808,255	753,259	740,784	729,581	700,802
Mass Flow (lb/hr)	3,582,000	3,322,000	3,262,000	3,202,000	3,077,000
Temperature (oF)	1,078	1,110	1,117	1,124	1,140
Moisture (% Vol.)	7.61	8.83	9.21	10.05	9.91
Oxygen (% Vol.)	12.71	12.56	12.51	12.36	12.48
Molecular Weight	28.46	28.33	28.28	28.19	28.20
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,017,973	948,707	932,995	918,885	882,639
Temperature (oF)	205	205	205	205	205
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	66.7	62.1	61.1	60.2	57.8
Stack Height (ft)	180	180	180	180	180

Source: General Electric, 1992.

Table A-7. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	9.00	9.00	9.00	9.00	9.00
lb/hr	9.00	9.00	9.00	9.00	9.00
TPY	38.07	38.07	38.07	38.07	38.07
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	4.86	4.45	4.36	4.28	4.06
TPY	20.54	18.84	18.45	18.10	17.15
Nitrogen Oxides					
Basis, ppm* (1)	25.0	25.0	25.0	25.0	25.0
lb/hr	161.9	148.5	145.3	142.6	135.0
TPY	684.72	627.98	614.78	603.09	571.14
Carbon Monoxide					
Basis, ppm+ (1)	15.0	15.0	15.0	15.0	15.0
lb/hr	48.8	44.9	44.0	42.9	41.3
TPY	206.55	189.96	186.03	181.52	174.63
VOCs (as methane)					
Basis, ppm+ (1)	1.5	1.5	1.5	1.6	1.5
lb/hr	2.79	2.57	2.55	2.62	2.36
TPY	11.80	10.85	10.77	11.06	9.98
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: General Electric, 1992.

Table A-8. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	6.26E-01	5.74E-01	5.62E-01	5.52E-01	5.23E-01
	TPY	2.65E+00	2.43E+00	2.38E+00	2.33E+00	2.21E+00

Source: EPA, 1990

Table A-9. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.80E-03	1.65E-03	1.61E-03	1.58E-03	1.50E-03
Matter	TPY	7.60E-03	6.97E-03	6.83E-03	6.70E-03	6.35E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.42E-01	1.31E-01	1.28E-01	1.25E-01	1.19E-01
	TPY	6.02E-01	5.52E-01	5.41E-01	5.30E-01	5.03E-01
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	2.07E+05	1.90E+05	1.86E+05	1.82E+05	1.73E+05
	TPY	8.76E+05	8.03E+05	7.86E+05	7.72E+05	7.31E+05

Source: (1) EPA, 1990

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Table A-10. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-11. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,515	1,515	1,515	1,515	1,515
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	205	205	205	205	205
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-12. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-13. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-14. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-15. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	17.00	17.00	17.00	9.00	9.00	9.00	1.00	1.00	1.00	18.00	18.00	18.00
TPY	2.55	2.55	2.55	38.07	38.07	38.07	4.38	4.38	4.38	45.00	45.00	45.00
Sulfur Dioxide:												
lb/hr	99.72	88.57	81.81	4.86	4.36	4.06	0.30	0.30	0.30	100.02	88.87	82.11
TPY	14.96	13.29	12.27	20.54	18.45	17.15	1.32	1.32	1.32	36.82	33.05	30.74
Nitrogen Oxides:												
lb/hr	326.22	290.19	268.04	161.87	145.34	135.02	10.00	10.00	10.00	336.22	300.19	278.04
TPY	48.93	43.53	40.21	684.72	614.78	571.14	43.80	43.80	43.80	777.46	702.11	655.15
Carbon Monoxide:												
lb/hr	98.41	88.62	83.20	48.83	43.98	41.28	10.00	10.00	10.00	108.41	98.62	93.20
TPY	14.76	13.29	12.48	206.55	186.03	174.63	43.80	43.80	43.80	265.12	243.12	230.91
VOCs (as methane):												
lb/hr	7.50	6.58	6.50	2.79	2.55	2.36	2.90	2.90	2.90	10.40	9.48	9.40
TPY	1.12	0.99	0.97	11.80	10.77	9.98	12.70	12.70	12.70	25.63	24.46	23.66
Lead:												
lb/hr	1.65E-02	1.46E-02	1.35E-02	NA	NA	NA	NA	NA	NA	1.65E-02	1.46E-02	1.35E-02
TPY	2.47E-03	2.19E-03	2.03E-03	NA	NA	NA	NA	NA	NA	2.47E-03	2.19E-03	2.03E-03

Table A-16. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	7.77E-03	6.90E-03	6.37E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.77E-03	6.90E-03	6.37E-03
	TPY	1.17E-03	1.04E-03	9.56E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.17E-03	1.04E-03	9.56E-04
Beryllium													
	lb/hr	4.62E-03	4.11E-03	3.79E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.62E-03	4.11E-03	3.79E-03
	TPY	6.94E-04	6.16E-04	5.69E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.94E-04	6.16E-04	5.69E-04
Mercury													
	lb/hr	5.55E-03	4.93E-03	4.55E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.55E-03	4.93E-03	4.55E-03
	TPY	8.32E-04	7.39E-04	6.83E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	8.32E-04	7.39E-04	6.83E-04
Fluoride													
	lb/hr	6.02E-02	5.35E-02	4.94E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.02E-02	5.35E-02	4.94E-02
	TPY	9.03E-03	8.02E-03	7.41E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.03E-03	8.02E-03	7.41E-03
Sulfuric Acid Mist	lb/hr	1.22E+01	1.08E+01	1.00E+01	6.26E-01	5.62E-01	5.23E-01	3.88E-02	3.88E-02	3.88E-02	1.23E+01	1.09E+01	1.01E+01
	TPY	1.83E+00	1.63E+00	1.50E+00	2.65E+00	2.38E+00	2.21E+00	1.70E-01	1.70E-01	1.70E-01	4.65E+00	4.18E+00	3.89E+00

Table A-17. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	2.59E-02	2.30E-02	2.12E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.59E-02	2.30E-02	2.12E-02
	TPY	3.88E-03	3.45E-03	3.19E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.88E-03	3.45E-03	3.19E-03
Nickel	lb/hr	3.14E-01	2.79E-01	2.58E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.14E-01	2.79E-01	2.58E-01
	TPY	4.72E-02	4.19E-02	3.87E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.72E-02	4.19E-02	3.87E-02
Cadmium	lb/hr	1.94E-02	1.73E-02	1.59E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.94E-02	1.73E-02	1.59E-02
	TPY	2.91E-03	2.59E-03	2.39E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.91E-03	2.59E-03	2.39E-03
Chromium	lb/hr	8.79E-02	7.80E-02	7.21E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	8.79E-02	7.80E-02	7.21E-02
	TPY	1.32E-02	1.17E-02	1.08E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.32E-02	1.17E-02	1.08E-02
Copper	lb/hr	5.18E-01	4.60E-01	4.25E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.18E-01	4.60E-01	4.25E-01
	TPY	7.77E-02	6.90E-02	6.37E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.77E-02	6.90E-02	6.37E-02
Vanadium	lb/hr	1.29E-01	1.14E-01	1.05E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.29E-01	1.14E-01	1.05E-01
	TPY	1.93E-02	1.71E-02	1.58E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.93E-02	1.71E-02	1.58E-02
Selenium	lb/hr	4.33E-02	3.85E-02	3.55E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.33E-02	3.85E-02	3.55E-02
	TPY	6.50E-03	5.77E-03	5.33E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.50E-03	5.77E-03	5.33E-03
Polycyclic Organic Matter	lb/hr	5.14E-04	4.57E-04	4.22E-04	1.80E-03	1.61E-03	1.50E-03	1.11E-04	1.11E-04	1.11E-04	1.91E-03	1.73E-03	1.61E-03
	TPY	7.71E-05	6.85E-05	6.33E-05	7.60E-03	6.83E-03	6.35E-03	4.87E-04	4.87E-04	4.87E-04	8.17E-03	7.38E-03	6.90E-03
Formaldehyde	lb/hr	7.49E-01	6.65E-01	6.15E-01	1.42E-01	1.28E-01	1.19E-01	8.81E-03	8.81E-03	8.81E-03	7.58E-01	6.74E-01	6.23E-01
	TPY	1.12E-01	9.98E-02	9.22E-02	6.02E-01	5.41E-01	5.03E-01	3.86E-02	3.86E-02	3.86E-02	7.53E-01	6.79E-01	6.33E-01
Carbon Dioxide	lb/hr	3.10E+05	2.76E+05	2.55E+05	2.07E+05	1.86E+05	1.73E+05	3.08E+02	3.02E+02	2.97E+02	3.11E+05	2.76E+05	2.55E+05
	TPY	4.65E+04	4.14E+04	3.83E+04	8.76E+05	7.86E+05	7.31E+05	1.35E+03	1.32E+03	1.30E+03	9.24E+05	8.29E+05	7.71E+05

Table A-18. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	4.04E-02	3.59E-02	3.32E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.04E-02	3.59E-02	3.32E-02
	TPY	6.06E-03	5.38E-03	4.97E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	6.06E-03	5.38E-03	4.97E-03
Barium													
	lb/hr	3.61E-02	3.21E-02	2.96E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.61E-02	3.21E-02	2.96E-02
	TPY	5.42E-03	4.81E-03	4.44E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	5.42E-03	4.81E-03	4.44E-03
Cobalt													
	lb/hr	1.68E-02	1.49E-02	1.38E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.68E-02	1.49E-02	1.38E-02
	TPY	2.51E-03	2.23E-03	2.06E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.51E-03	2.23E-03	2.06E-03
Zinc													
	lb/hr	1.26E+00	1.12E+00	1.04E+00	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.26E+00	1.12E+00	1.04E+00
	TPY	1.90E-01	1.68E-01	1.56E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.90E-01	1.68E-01	1.56E-01
Chlorine													
	lb/hr	4.99E-02	4.43E-02	4.09E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.99E-02	4.43E-02	4.09E-02
	TPY	7.48E-03	6.64E-03	6.14E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	7.48E-03	6.64E-03	6.14E-03

GE7FATOT
6/12/92

Table A-1A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	129,200.0		111,000.0		98,500.0
Heat Rate (Btu/kwh)	11,430.0		11,800.0		12,280.0
Heat Input (mmBtu/hr)	1,476.8		1,309.8		1,209.6
Fuel Oil (lb/hr)	79,609.5		70,609.2		65,206.5
Fuel:					
Heat Content,LHV (Btu/lb)	18,550		18,550		18,550
CT Exhaust:					
Volume Flow (acfm)	1,988,010		1,869,045		1,802,083
Volume Flow (scfm)	645,553		597,370		573,193
Mass Flow (lb/hr)	2,837,000		2,619,000		2,510,000
Temperature (oF)	1,166		1,192		1,200
Moisture (% Vol.)	11.96		12.40		12.48
Oxygen (% Vol.)	10.57		10.81		11.07
Molecular Weight	28.23		28.16		28.13
Water Injected (lb/hr)	105,120		80,490		68,760
HRSG Stack (without duct burner):					
Volume Flow (acfm)	806,941		746,713		716,491
Temperature (oF)	200		200		200
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	52.9		48.9		46.9
Stack Height (ft)	180		180		180

Source: General Electric, 1992.

Table A-2A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	17.0		17.0		17.0
lb/hr	17.0		17.0		17.0
TPY	2.6		2.6		2.6
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	79.61		70.61		65.21
TPY	11.9		10.6		9.8
Nitrogen Oxides					
Basis, ppm* (1)	42.0		42.0		42.0
lb/hr	257.7		228.4		211.0
TPY	38.7		34.3		31.7
Carbon Monoxide					
Basis, ppm+ (1)	30.0		30.0		30.0
lb/hr	74.3		68.4		65.6
TPY	11.1		10.3		9.8
VOCs (as methane)					
Basis, ppm+ (1)	4.0		4.0		4.1
lb/hr	5.66		5.21		5.12
TPY	0.8		0.8		0.8
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.31E-02		1.17E-02		1.08E-02
TPY	1.97E-03		1.75E-03		1.61E-03

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: (1) General Electric, 1992; (2) EPA, 1990

Table A-3A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	6.20E-03		5.50E-03		5.08E-03
	TPY	9.30E-04		8.25E-04		7.62E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	3.69E-03		3.27E-03		3.02E-03
	TPY	5.54E-04		4.91E-04		4.54E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	4.43E-03		3.93E-03		3.63E-03
	TPY	6.65E-04		5.89E-04		5.44E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	4.80E-02		4.26E-02		3.94E-02
	TPY	7.21E-03		6.39E-03		5.90E-03
Sulfuric Acid	% of SO2	8		8		8
Mist	lb/hr	9.75E+00		8.65E+00		7.99E+00
	TPY	1.46E+00		1.30E+00		1.20E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-4A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	2.07E-02		1.83E-02		1.69E-02
	TPY	3.10E-03		2.75E-03		2.54E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	2.51E-01		2.23E-01		2.06E-01
	TPY	3.77E-02		3.34E-02		3.08E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.55E-02		1.38E-02		1.27E-02
	TPY	2.33E-03		2.06E-03		1.91E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	7.01E-02		6.22E-02		5.75E-02
	TPY	1.05E-02		9.33E-03		8.62E-03
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	4.13E-01		3.67E-01		3.39E-01
	TPY	6.20E-02		5.50E-02		5.08E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	1.03E-01		9.10E-02		8.41E-02
	TPY	1.54E-02		1.37E-02		1.26E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	3.46E-02		3.07E-02		2.83E-02
	TPY	5.19E-03		4.60E-03		4.25E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	4.11E-04		3.64E-04		3.36E-04
Matter	TPY	6.16E-05		5.46E-05		5.04E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	5.98E-01		5.30E-01		4.90E-01
	TPY	8.97E-02		7.96E-02		7.35E-02
Carbon	% Exhaust Gas	5.54		5.31		5.11
Dioxide	lb/hr	2.45E+05		2.17E+05		2.01E+05
	TPY	3.68E+04		3.26E+04		3.01E+04

Source: (1) EPA, 1990

Table A-5A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	3.23E-02		2.86E-02		2.64E-02
	TPY	4.84E-03		4.29E-03		3.96E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	2.88E-02		2.56E-02		2.36E-02
	TPY	4.32E-03		3.84E-03		3.54E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.34E-02		1.19E-02		1.10E-02
	TPY	2.01E-03		1.78E-03		1.64E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	1.01E+00		8.95E-01		8.26E-01
	TPY	1.51E-01		1.34E-01		1.24E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	3.98E-02		3.53E-02		3.26E-02
	TPY	5.97E-03		5.30E-03		4.89E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	119,900.0	106,500.0	103,100.0	99,500.0	90,900.0
Heat Rate (Btu/kwh)	10,770.0	11,070.0	11,340.0	11,510.0	11,890.0
Heat Input (mmBtu/hr)	1,291.3	1,179.0	1,169.2	1,145.2	1,080.8
Natural Gas (lb/hr)	60,019.7	54,796.9	54,341.3	53,230.1	50,234.8
(cf/hr)	1,359,287	1,241,005	1,230,688	1,205,521	1,137,685
Fuel:					
Heat Content, LHV (Btu/lb)	21,515	21,515	21,515	21,515	21,515
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,920,685	1,845,077	1,827,352	1,808,470	1,757,157
Volume Flow (scfm)	619,500	588,641	581,580	575,224	558,903
Mass Flow (lb/hr)	2,744,000	2,595,000	2,560,000	2,524,000	2,454,000
Temperature (oF)	1,177	1,195	1,199	1,200	1,200
Moisture (% Vol.)	7.84	8.98	9.34	10.14	9.89
Oxygen (% Vol.)	12.46	12.41	12.39	12.28	12.52
Molecular Weight	28.45	28.32	28.27	28.18	28.20
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack (without duct burner):					
Volume Flow (acfm)	774,375	735,801	726,975	719,030	698,629
Temperature (oF)	200	200	200	200	200
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	50.7	48.2	47.6	47.1	45.8
Stack Height (ft)	180	180	180	180	180

Source: General Electric, 1992.

Table A-7A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	9.00	9.00	9.00	9.00	9.00
lb/hr	9.00	9.00	9.00	9.00	9.00
TPY	38.07	38.07	38.07	38.07	38.07
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	3.88	3.55	3.52	3.44	3.25
TPY	16.43	15.00	14.87	14.57	13.75
Nitrogen Oxides					
Basis, ppm* (1)	25.0	25.0	25.0	25.0	25.0
lb/hr	127.9	118.1	115.7	113.5	107.1
TPY	540.88	499.71	489.59	480.01	452.93
Carbon Monoxide					
Basis, ppm+ (1)	15.0	15.0	15.0	15.0	15.0
lb/hr	37.3	35.0	34.5	33.8	32.9
TPY	157.92	148.20	145.84	142.98	139.31
VOCs (as methane)					
Basis, ppm+ (1)	1.5	1.5	1.5	1.6	1.5
lb/hr	2.13	2.00	2.00	2.06	1.88
TPY	9.02	8.47	8.44	8.71	7.96
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: General Electric, 1992.

Table A-8A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	5.01E-01	4.57E-01	4.53E-01	4.44E-01	4.19E-01
	TPY	2.12E+00	1.93E+00	1.92E+00	1.88E+00	1.77E+00

Source: EPA, 1990

Table A-9A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.44E-03	1.31E-03	1.30E-03	1.27E-03	1.20E-03
Matter	TPY	6.08E-03	5.55E-03	5.50E-03	5.39E-03	5.09E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.14E-01	1.04E-01	1.03E-01	1.01E-01	9.52E-02
	TPY	4.81E-01	4.39E-01	4.36E-01	4.27E-01	4.03E-01
Carbon	% Exhaust Gas	3.85	3.75	3.72	3.68	3.58
Dioxide	lb/hr	1.63E+05	1.51E+05	1.48E+05	1.45E+05	1.37E+05
	TPY	6.91E+05	6.40E+05	6.27E+05	6.14E+05	5.80E+05

Source: (1) EPA, 1990

Table A-10A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-GE PG7221(FA), Dry Low NOx II Combustion System, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-11A. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,504	1,504	1,504	1,504	1,504
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	200	200	200	200	200
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-12A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-13A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-14A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-15A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	17.00	17.00	17.00	9.00	9.00	9.00	1.00	1.00	1.00	18.00	18.00	18.00
TPY	2.55	2.55	2.55	38.07	38.07	38.07	4.38	4.38	4.38	45.00	45.00	45.00
Sulfur Dioxide:												
lb/hr	79.61	70.61	65.21	3.88	3.52	3.25	0.30	0.30	0.30	79.91	70.91	65.51
TPY	11.94	10.59	9.78	16.43	14.87	13.75	1.32	1.32	1.32	29.69	26.78	24.85
Nitrogen Oxides:												
lb/hr	257.71	228.37	211.04	127.87	115.74	107.07	10.00	10.00	10.00	267.71	238.37	221.04
TPY	38.66	34.26	31.66	540.88	489.59	452.93	43.80	43.80	43.80	623.33	567.64	528.38
Carbon Monoxide:												
lb/hr	74.33	68.44	65.61	37.33	34.48	32.93	10.00	10.00	10.00	84.33	78.44	75.61
TPY	11.15	10.27	9.84	157.92	145.84	139.31	43.80	43.80	43.80	212.87	199.91	192.95
VOCs (as methane):												
lb/hr	5.66	5.21	5.12	2.13	2.00	1.88	2.90	2.90	2.90	8.56	8.11	8.02
TPY	0.85	0.78	0.77	9.02	8.44	7.96	12.70	12.70	12.70	22.58	21.93	21.43
Lead:												
lb/hr	1.31E-02	1.17E-02	1.08E-02	NA	NA	NA	NA	NA	NA	1.31E-02	1.17E-02	1.08E-02
TPY	1.97E-03	1.75E-03	1.61E-03	NA	NA	NA	NA	NA	NA	1.97E-03	1.75E-03	1.61E-03

Table A-16A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	6.20E-03	5.50E-03	5.08E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.20E-03	5.50E-03	5.08E-03
	TPY	9.30E-04	8.25E-04	7.62E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.30E-04	8.25E-04	7.62E-04
Beryllium													
	lb/hr	3.69E-03	3.27E-03	3.02E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.69E-03	3.27E-03	3.02E-03
	TPY	5.54E-04	4.91E-04	4.54E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.54E-04	4.91E-04	4.54E-04
Mercury													
	lb/hr	4.43E-03	3.93E-03	3.63E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.43E-03	3.93E-03	3.63E-03
	TPY	6.65E-04	5.89E-04	5.44E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.65E-04	5.89E-04	5.44E-04
Fluoride													
	lb/hr	4.80E-02	4.26E-02	3.94E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.80E-02	4.26E-02	3.94E-02
	TPY	7.21E-03	6.39E-03	5.90E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.21E-03	6.39E-03	5.90E-03
Sulfuric Acid Mist	lb/hr	9.75E+00	8.65E+00	7.99E+00	5.01E-01	4.53E-01	4.19E-01	3.88E-02	3.88E-02	3.88E-02	9.79E+00	8.69E+00	8.03E+00
	TPY	1.46E+00	1.30E+00	1.20E+00	2.12E+00	1.92E+00	1.77E+00	1.70E-01	1.70E-01	1.70E-01	3.75E+00	3.39E+00	3.14E+00

Table A-17A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility- GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	2.07E-02	1.83E-02	1.69E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.07E-02	1.83E-02	1.69E-02
	TPY	3.10E-03	2.75E-03	2.54E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.10E-03	2.75E-03	2.54E-03
Nickel	lb/hr	2.51E-01	2.23E-01	2.06E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.51E-01	2.23E-01	2.06E-01
	TPY	3.77E-02	3.34E-02	3.08E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.77E-02	3.34E-02	3.08E-02
Cadmium	lb/hr	1.55E-02	1.38E-02	1.27E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.55E-02	1.38E-02	1.27E-02
	TPY	2.33E-03	2.06E-03	1.91E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.33E-03	2.06E-03	1.91E-03
Chromium	lb/hr	7.01E-02	6.22E-02	5.75E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.01E-02	6.22E-02	5.75E-02
	TPY	1.05E-02	9.33E-03	8.62E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.05E-02	9.33E-03	8.62E-03
Copper	lb/hr	4.13E-01	3.67E-01	3.39E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.13E-01	3.67E-01	3.39E-01
	TPY	6.20E-02	5.50E-02	5.08E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.20E-02	5.50E-02	5.08E-02
Vanadium	lb/hr	1.03E-01	9.10E-02	8.41E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.03E-01	9.10E-02	8.41E-02
	TPY	1.54E-02	1.37E-02	1.26E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.54E-02	1.37E-02	1.26E-02
Selenium	lb/hr	3.46E-02	3.07E-02	2.83E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.46E-02	3.07E-02	2.83E-02
	TPY	5.19E-03	4.60E-03	4.25E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.19E-03	4.60E-03	4.25E-03
Polycyclic Organic Matter	lb/hr	4.11E-04	3.64E-04	3.36E-04	1.44E-03	1.30E-03	1.20E-03	1.11E-04	1.11E-04	1.11E-04	1.55E-03	1.41E-03	1.31E-03
	TPY	6.16E-05	5.46E-05	5.04E-05	6.08E-03	5.50E-03	5.09E-03	4.87E-04	4.87E-04	4.87E-04	6.63E-03	6.05E-03	5.63E-03
Formaldehyde	lb/hr	5.98E-01	5.30E-01	4.90E-01	1.14E-01	1.03E-01	9.52E-02	8.81E-03	8.81E-03	8.81E-03	6.07E-01	5.39E-01	4.99E-01
	TPY	8.97E-02	7.96E-02	7.35E-02	4.81E-01	4.36E-01	4.03E-01	3.86E-02	3.86E-02	3.86E-02	6.10E-01	5.54E-01	5.15E-01
Carbon Dioxide	lb/hr	2.45E+05	2.17E+05	2.01E+05	1.63E+05	1.48E+05	1.37E+05	3.08E+02	3.02E+02	2.97E+02	2.45E+05	2.18E+05	2.01E+05
	TPY	3.68E+04	3.26E+04	3.01E+04	6.91E+05	6.27E+05	5.80E+05	1.35E+03	1.32E+03	1.30E+03	7.29E+05	6.61E+05	6.11E+05

Table A-18A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-
GE PG7221(FA), Dry Low NOx II Combustion System, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	3.23E-02	2.86E-02	2.64E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.23E-02	2.86E-02	2.64E-02
	TPY	4.84E-03	4.29E-03	3.96E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.84E-03	4.29E-03	3.96E-03
Barium													
	lb/hr	2.88E-02	2.56E-02	2.36E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.88E-02	2.56E-02	2.36E-02
	TPY	4.32E-03	3.84E-03	3.54E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.32E-03	3.84E-03	3.54E-03
Cobalt													
	lb/hr	1.34E-02	1.19E-02	1.10E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.34E-02	1.19E-02	1.10E-02
	TPY	2.01E-03	1.78E-03	1.64E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.01E-03	1.78E-03	1.64E-03
Zinc													
	lb/hr	1.01E+00	8.95E-01	8.26E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.01E+00	8.95E-01	8.26E-01
	TPY	1.51E-01	1.34E-01	1.24E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.51E-01	1.34E-01	1.24E-01
Chlorine													
	lb/hr	3.98E-02	3.53E-02	3.26E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.98E-02	3.53E-02	3.26E-02
	TPY	5.97E-03	5.30E-03	4.89E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	5.97E-03	5.30E-03	4.89E-03

Table A-19. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	171,730.0		160,550.0		145,180.0
Heat Rate (Btu/kwh)	9,290.0		9,570.0		9,880.0
Heat Input (mmBtu/hr)	1,595.4		1,536.5		1,434.4
Fuel Oil (lb/hr)	88,142.1		84,887.5		79,247.4
Fuel:					
Heat Content,LHV (Btu/lb)	18,100		18,100		18,100
CT Exhaust:					
Volume Flow (acfm)	2,378,254		2,347,829		2,246,134
Volume Flow (scfm)	817,525		792,111		749,184
Mass Flow (lb/hr)	3,590,650		3,479,030		3,281,070
Temperature (oF)	1,076		1,105		1,123
Moisture (% Vol.)	11.78		11.78		12.44
Oxygen (% Vol.)	11.85		11.85		11.79
Molecular Weight	28.21		28.21		28.13
Water Injected (lb/hr)	132,210		127,340		118,880
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,029,648		997,640		943,575
Temperature (oF)	205		205		205
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	67.4		65.3		61.8
Stack Height (ft)	180		180		180

Source: Westinghouse, 1992.

Table A-20. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	40.4		39.1		36.7
lb/hr	40.4		39.1		36.7
TPY	6.1		5.9		5.5
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	91.05		87.01		82.02
TPY	13.7		13.1		12.3
Nitrogen Oxides					
Basis, ppm* (1)	44.5		42.0		42.0
lb/hr	290.9		266.0		248.7
TPY	43.6		39.9		37.3
Carbon Monoxide					
Basis, ppm+ (1)	52.0		51.6		51.4
lb/hr	163.5		157.0		147.0
TPY	24.5		23.6		22.0
VOCs (as methane)					
Basis, ppm+ (1)	10.5		10.5		10.5
lb/hr	18.86		18.28		17.16
TPY	2.8		2.7		2.6
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.42E-02		1.37E-02		1.28E-02
TPY	2.13E-03		2.05E-03		1.91E-03

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: (1) Westinghouse, 1992; (2) EPA, 1990

Table A-21. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	6.70E-03		6.45E-03		6.02E-03
	TPY	1.01E-03		9.68E-04		9.04E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	3.99E-03		3.84E-03		3.59E-03
	TPY	5.98E-04		5.76E-04		5.38E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	4.79E-03		4.61E-03		4.30E-03
	TPY	7.18E-04		6.91E-04		6.45E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	5.19E-02		5.00E-02		4.67E-02
	TPY	7.79E-03		7.50E-03		7.00E-03
Sulfuric Acid Mist	% of SO2	8		8		8
	lb/hr	1.12E+01		1.07E+01		1.00E+01
	TPY	1.67E+00		1.60E+00		1.51E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-22. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	2.23E-02		2.15E-02		2.01E-02
	TPY	3.35E-03		3.23E-03		3.01E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	2.71E-01		2.61E-01		2.44E-01
	TPY	4.07E-02		3.92E-02		3.66E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.68E-02		1.61E-02		1.51E-02
	TPY	2.51E-03		2.42E-03		2.26E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	7.58E-02		7.30E-02		6.81E-02
	TPY	1.14E-02		1.09E-02		1.02E-02
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	4.47E-01		4.30E-01		4.02E-01
	TPY	6.70E-02		6.45E-02		6.02E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	1.11E-01		1.07E-01		9.97E-02
	TPY	1.66E-02		1.60E-02		1.50E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	3.74E-02		3.60E-02		3.36E-02
	TPY	5.60E-03		5.40E-03		5.04E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	4.44E-04		4.27E-04		3.99E-04
Matter	TPY	6.65E-05		6.41E-05		5.98E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	6.46E-01		6.22E-01		5.81E-01
	TPY	9.69E-02		9.33E-02		8.71E-02
Carbon	% Exhaust Gas	5.00		5.00		4.94
Dioxide	lb/hr	2.80E+05		2.71E+05		2.54E+05
	TPY	4.20E+04		4.07E+04		3.80E+04

Source: (1) EPA, 1990

Table A-23. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility- Westinghouse 501F, Conventional Combustor, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	3.49E-02		3.36E-02		3.13E-02
	TPY	5.23E-03		5.03E-03		4.70E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	3.11E-02		3.00E-02		2.80E-02
	TPY	4.67E-03		4.50E-03		4.20E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.45E-02		1.39E-02		1.30E-02
	TPY	2.17E-03		2.09E-03		1.95E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	1.09E+00		1.05E+00		9.80E-01
	TPY	1.64E-01		1.57E-01		1.47E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	4.41E-02		4.24E-02		3.96E-02
	TPY	6.61E-03		6.37E-03		5.94E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-24. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility- Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	168,010.0	146,540.0	141,910.0	138,110.0	127,710.0
Heat Rate (Btu/kwh)	9,480.0	9,910.0	10,020.0	10,120.0	10,400.0
Heat Input (mmBtu/hr)	1,592.7	1,452.2	1,421.9	1,397.7	1,328.2
Natural Gas (lb/hr)	80,849.5	73,716.3	72,179.6	70,947.9	67,420.5
(cf/hr)	1,676,563	1,528,644	1,496,777	1,471,235	1,398,088
Fuel:					
Heat Content, LHV (Btu/lb)	19,700	19,700	19,700	19,700	19,700
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	2,386,805	2,256,129	2,226,061	2,203,500	2,134,002
Volume Flow (scfm)	828,011	770,528	757,320	745,800	716,764
Mass Flow (lb/hr)	3,673,720	3,402,010	3,339,570	3,276,980	3,150,780
Temperature (oF)	1,062	1,086	1,092	1,100	1,112
Moisture (% Vol.)	7.23	8.42	8.79	9.65	9.53
Oxygen (% Vol.)	13.04	12.92	12.87	12.69	12.79
Molecular Weight	28.50	28.36	28.32	28.22	28.23
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack (without duct burner):					
Volume Flow (acfm)	1,042,855	970,456	953,821	939,313	902,743
Temperature (oF)	205	205	205	205	205
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	68.3	63.6	62.5	61.5	59.1
Stack Height (ft)	180	180	180	180	180

Source: Westinghouse, 1992.

Table A-25. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	6.40	6.00	5.90	5.80	5.60
lb/hr	6.40	6.00	5.90	5.80	5.60
TPY	27.07	25.38	24.96	24.53	23.69
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	4.79	4.37	4.28	4.20	3.99
TPY	20.26	18.47	18.09	17.78	16.90
Nitrogen Oxides					
Basis, ppm* (1)	26.5	25.0	25.0	25.0	25.0
lb/hr	169.0	145.4	142.3	140.2	133.1
TPY	715.05	615.25	602.04	592.91	562.93
Carbon Monoxide					
Basis, ppm+ (1)	10.0	10.4	10.3	10.2	10.2
lb/hr	33.5	32.0	31.0	30.0	28.8
TPY	141.65	135.33	131.20	126.74	121.97
VOCs (as methane)					
Basis, ppm+ (1)	4.2	4.1	4.1	4.2	4.3
lb/hr	8.04	7.21	7.05	7.05	6.95
TPY	34.00	30.49	29.84	29.82	29.38
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Source: Westinghouse, 1992.

Table A-26. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	6.18E-01	5.63E-01	5.51E-01	5.42E-01	5.15E-01
	TPY	2.61E+00	2.38E+00	2.33E+00	2.29E+00	2.18E+00

Source: EPA, 1990

Table A-27. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.77E-03	1.62E-03	1.58E-03	1.56E-03	1.48E-03
Matter	TPY	7.50E-03	6.84E-03	6.69E-03	6.58E-03	6.25E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.40E-01	1.28E-01	1.25E-01	1.23E-01	1.17E-01
	TPY	5.94E-01	5.41E-01	5.30E-01	5.21E-01	4.95E-01
Carbon	% Exhaust Gas	3.61	3.54	3.53	3.52	3.48
Dioxide	lb/hr	2.05E+05	1.87E+05	1.83E+05	1.80E+05	1.71E+05
	TPY	8.66E+05	7.91E+05	7.75E+05	7.61E+05	7.23E+05

Source: (1) EPA, 1990

Table A-28. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-29. Design Information for DESTEC Central Florida Cogeneration Facility- Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,515	1,515	1,515	1,515	1,515
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	205	205	205	205	205
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-30. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-31. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-32. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

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Table A-33. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility- Westinghouse 501F, Dry Low NOx Combustor, Base Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	40.40	39.10	36.70	6.40	5.90	5.60	1.00	1.00	1.00	41.40	40.10	37.70
TPY	6.06	5.87	5.51	27.07	24.96	23.69	4.38	4.38	4.38	37.51	35.20	33.57
Sulfur Dioxide:												
lb/hr	91.05	87.01	82.02	4.79	4.28	3.99	0.30	0.30	0.30	91.35	87.31	82.32
TPY	13.66	13.05	12.30	20.26	18.09	16.90	1.32	1.32	1.32	35.24	32.46	30.52
Nitrogen Oxides:												
lb/hr	290.93	266.05	248.65	169.04	142.33	133.08	10.00	10.00	10.00	300.93	276.05	258.65
TPY	43.64	39.91	37.30	715.05	602.04	562.93	43.80	43.80	43.80	802.48	685.75	644.03
Carbon Monoxide:												
lb/hr	163.49	157.04	146.99	33.49	31.02	28.83	10.00	10.00	10.00	173.49	167.04	156.99
TPY	24.52	23.56	22.05	141.65	131.20	121.97	43.80	43.80	43.80	209.97	198.55	187.82
VOCs (as methane):												
lb/hr	18.86	18.28	17.16	8.04	7.05	6.95	2.90	2.90	2.90	21.76	21.18	20.06
TPY	2.83	2.74	2.57	34.00	29.84	29.38	12.70	12.70	12.70	49.53	45.29	44.66
Lead:												
lb/hr	1.42E-02	1.37E-02	1.28E-02	NA	NA	NA	NA	NA	NA	1.42E-02	1.37E-02	1.28E-02
TPY	2.13E-03	2.05E-03	1.91E-03	NA	NA	NA	NA	NA	NA	2.13E-03	2.05E-03	1.91E-03

Table A-34. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	6.70E-03	6.45E-03	6.02E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.70E-03	6.45E-03	6.02E-03
	TPY	1.01E-03	9.68E-04	9.04E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.01E-03	9.68E-04	9.04E-04
Beryllium													
	lb/hr	3.99E-03	3.84E-03	3.59E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.99E-03	3.84E-03	3.59E-03
	TPY	5.98E-04	5.76E-04	5.38E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.98E-04	5.76E-04	5.38E-04
Mercury													
	lb/hr	4.79E-03	4.61E-03	4.30E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.79E-03	4.61E-03	4.30E-03
	TPY	7.18E-04	6.91E-04	6.45E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.18E-04	6.91E-04	6.45E-04
Fluoride													
	lb/hr	5.19E-02	5.00E-02	4.67E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.19E-02	5.00E-02	4.67E-02
	TPY	7.79E-03	7.50E-03	7.00E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.79E-03	7.50E-03	7.00E-03
Sulfuric Acid Mist	lb/hr	1.12E+01	1.07E+01	1.00E+01	6.18E-01	5.51E-01	5.15E-01	3.88E-02	3.88E-02	3.88E-02	1.12E+01	1.07E+01	1.01E+01
	TPY	1.67E+00	1.60E+00	1.51E+00	2.61E+00	2.33E+00	2.18E+00	1.70E-01	1.70E-01	1.70E-01	4.46E+00	4.10E+00	3.86E+00

Table A-35. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, Base Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	2.23E-02	2.15E-02	2.01E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.23E-02	2.15E-02	2.01E-02
	TPY	3.35E-03	3.23E-03	3.01E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.35E-03	3.23E-03	3.01E-03
Nickel	lb/hr	2.71E-01	2.61E-01	2.44E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.71E-01	2.61E-01	2.44E-01
	TPY	4.07E-02	3.92E-02	3.66E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.07E-02	3.92E-02	3.66E-02
Cadmium	lb/hr	1.68E-02	1.61E-02	1.51E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.68E-02	1.61E-02	1.51E-02
	TPY	2.51E-03	2.42E-03	2.26E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.51E-03	2.42E-03	2.26E-03
Chromium	lb/hr	7.58E-02	7.30E-02	6.81E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	7.58E-02	7.30E-02	6.81E-02
	TPY	1.14E-02	1.09E-02	1.02E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.14E-02	1.09E-02	1.02E-02
Copper	lb/hr	4.47E-01	4.30E-01	4.02E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.47E-01	4.30E-01	4.02E-01
	TPY	6.70E-02	6.45E-02	6.02E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.70E-02	6.45E-02	6.02E-02
Vanadium	lb/hr	1.11E-01	1.07E-01	9.97E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.11E-01	1.07E-01	9.97E-02
	TPY	1.66E-02	1.60E-02	1.50E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.66E-02	1.60E-02	1.50E-02
Selenium	lb/hr	3.74E-02	3.60E-02	3.36E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.74E-02	3.60E-02	3.36E-02
	TPY	5.60E-03	5.40E-03	5.04E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.60E-03	5.40E-03	5.04E-03
Polycyclic Organic Matter	lb/hr	4.44E-04	4.27E-04	3.99E-04	1.77E-03	1.58E-03	1.48E-03	1.11E-04	1.11E-04	1.11E-04	1.88E-03	1.69E-03	1.59E-03
	TPY	6.65E-05	6.41E-05	5.98E-05	7.50E-03	6.69E-03	6.25E-03	4.87E-04	4.87E-04	4.87E-04	8.05E-03	7.25E-03	6.80E-03
Formaldehyde	lb/hr	6.46E-01	6.22E-01	5.81E-01	1.40E-01	1.25E-01	1.17E-01	8.81E-03	8.81E-03	8.81E-03	6.55E-01	6.31E-01	5.90E-01
	TPY	9.69E-02	9.33E-02	8.71E-02	5.94E-01	5.30E-01	4.95E-01	3.86E-02	3.86E-02	3.86E-02	7.29E-01	6.62E-01	6.21E-01
Carbon Dioxide	lb/hr	2.80E+05	2.71E+05	2.54E+05	2.05E+05	1.83E+05	1.71E+05	3.08E+02	3.02E+02	2.97E+02	2.80E+05	2.72E+05	2.54E+05
	TPY	4.20E+04	4.07E+04	3.80E+04	8.66E+05	7.75E+05	7.23E+05	1.35E+03	1.32E+03	1.30E+03	9.10E+05	8.17E+05	7.62E+05

Table A-19A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Data	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A	B	C	D	E	F
General:					
Power (kW)	134,010.0		112,180.0		101,370.0
Heat Rate (Btu/kwh)	9,940.0		10,590.0		11,010.0
Heat Input (mmBtu/hr)	1,332.1		1,188.0		1,116.1
Fuel Oil (lb/hr)	73,594.4		65,634.6		61,662.1
Fuel:					
Heat Content,LHV (Btu/lb)	18,100		18,100		18,100
CT Exhaust:					
Volume Flow (acfm)	2,038,400		1,904,295		1,835,565
Volume Flow (scfm)	700,700		642,471		612,241
Mass Flow (lb/hr)	3,099,150		2,824,930		2,684,120
Temperature (oF)	1,076		1,105		1,123
Moisture (% Vol.)	9.79		11.19		11.87
Oxygen (% Vol.)	12.48		12.36		12.30
Molecular Weight	28.41		28.24		28.16
Water Injected (lb/hr)	110,400		98,460		92,490
HRSG Stack (without duct burner):					
Volume Flow (acfm)	875,875		803,089		765,302
Temperature (oF)	200		200		200
Diameter (ft)	18.0		18.0		18.0
Velocity (ft/sec)	57.4		52.6		50.1
Stack Height (ft)	180		180		180

Source: Westinghouse, 1992.

Table A-20A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
Hours of Operation	300		300		300
Particulate					
Basis, lb/hr (1)	34.2		30.8		29.2
lb/hr	34.2		30.8		29.2
TPY	5.1		4.6		4.4
Sulfur Dioxide					
Basis, % sulfur	0.05		0.05		0.05
lb/hr	75.95		68.00		64.01
TPY	11.4		10.2		9.6
Nitrogen Oxides					
Basis, ppm* (1)	44.3		42.0		42.0
lb/hr	240.0		203.1		191.0
TPY	36.0		30.5		28.7
Carbon Monoxide					
Basis, ppm+ (1)	51.5		51.5		51.5
lb/hr	142.0		128.0		121.0
TPY	21.3		19.2		18.2
VOCs (as methane)					
Basis, ppm+ (1)	10.2		10.6		10.5
lb/hr	16.06		15.07		14.11
TPY	2.4		2.3		2.1
Lead					
Basis, lb/10E+12 Btu (2)	8.9		8.9		8.9
lb/hr	1.19E-02		1.06E-02		9.93E-03
TPY	1.78E-03		1.59E-03		1.49E-03

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: (1) Westinghouse, 1992; (2) EPA, 1990

Table A-21A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2		4.2		4.2
	lb/hr	5.59E-03		4.99E-03		4.69E-03
	TPY	8.39E-04		7.48E-04		7.03E-04
Beryllium	lb/10E+12 Btu (1)	2.5		2.5		2.5
	lb/hr	3.33E-03		2.97E-03		2.79E-03
	TPY	5.00E-04		4.45E-04		4.19E-04
Mercury	lb/10E+12 Btu (1)	3		3		3
	lb/hr	4.00E-03		3.56E-03		3.35E-03
	TPY	5.99E-04		5.35E-04		5.02E-04
Fluoride	pg/J (2)	14		14		14
	lb/hr	4.33E-02		3.87E-02		3.63E-02
	TPY	6.50E-03		5.80E-03		5.45E-03
Sulfuric Acid Mist	% of SO2	8		8		8
	lb/hr	9.30E+00		8.33E+00		7.84E+00
	TPY	1.40E+00		1.25E+00		1.18E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990; (2) EPA, 1981

Table A-22A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant	Units	Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	14		14		14
	lb/hr	1.86E-02		1.66E-02		1.56E-02
	TPY	2.80E-03		2.49E-03		2.34E-03
Nickel	lb/10E+12 Btu (1)	170		170		170
	lb/hr	2.26E-01		2.02E-01		1.90E-01
	TPY	3.40E-02		3.03E-02		2.85E-02
Cadmium	lb/10E+12 Btu (1)	10.5		10.5		10.5
	lb/hr	1.40E-02		1.25E-02		1.17E-02
	TPY	2.10E-03		1.87E-03		1.76E-03
Chromium	lb/10E+12 Btu (1)	47.5		47.5		47.5
	lb/hr	6.33E-02		5.64E-02		5.30E-02
	TPY	9.49E-03		8.46E-03		7.95E-03
Copper	lb/10E+12 Btu (1)	280		280		280
	lb/hr	3.73E-01		3.33E-01		3.13E-01
	TPY	5.59E-02		4.99E-02		4.69E-02
Vanadium	lb/10E+12 Btu (1)	69.5		69.5		69.5
	lb/hr	9.26E-02		8.26E-02		7.76E-02
	TPY	1.39E-02		1.24E-02		1.16E-02
Selenium	lb/10E+12 Btu (1)	23.42		23.42		23.42
	lb/hr	3.12E-02		2.78E-02		2.61E-02
	TPY	4.68E-03		4.17E-03		3.92E-03
Polycyclic	lb/10E+12 Btu (1)	0.278		0.278		0.278
Organic	lb/hr	3.70E-04		3.30E-04		3.10E-04
Matter	TPY	5.55E-05		4.95E-05		4.65E-05
Formaldehyde	lb/10E+12 Btu (1)	405		405		405
	lb/hr	5.39E-01		4.81E-01		4.52E-01
	TPY	8.09E-02		7.22E-02		6.78E-02
Carbon	% Exhaust Gas	4.84		4.71		4.64
Dioxide	lb/hr	2.32E+05		2.07E+05		1.95E+05
	TPY	3.49E+04		3.11E+04		2.92E+04

Source: (1) EPA, 1990

Table A-23A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Conventional Combustor, Distillate Oil, 70 Percent Load

Pollutant		Gas Turbine Fuel Oil 27oF	* Not Available * Gas Turbine Fuel Oil 64oF	Gas Turbine Fuel Oil 72oF	* Not Available * Gas Turbine Fuel Oil 79oF	Gas Turbine Fuel Oil 97oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4		9.4		9.4
	lb/hr	2.91E-02		2.60E-02		2.44E-02
	TPY	4.36E-03		3.89E-03		3.66E-03
Barium	pg/J (1)	8.4		8.4		8.4
	lb/hr	2.60E-02		2.32E-02		2.18E-02
	TPY	3.90E-03		3.48E-03		3.27E-03
Cobalt	pg/J (1)	3.9		3.9		3.9
	lb/hr	1.21E-02		1.08E-02		1.01E-02
	TPY	1.81E-03		1.62E-03		1.52E-03
Zinc	pg/J (1)	294		294		294
	lb/hr	9.10E-01		8.12E-01		7.63E-01
	TPY	1.37E-01		1.22E-01		1.14E-01
Chlorine	ppm	0.5		0.5		0.5
	lb/hr	3.68E-02		3.28E-02		3.08E-02
	TPY	5.52E-03		4.92E-03		4.62E-03

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-24A. Design Information and Stack Parameters for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Data	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	117,480.0	102,390.0	99,140.0	96,460.0	89,150.0
Heat Rate (Btu/kwh)	10,540.0	11,100.0	11,240.0	11,370.0	11,720.0
Heat Input (mmBtu/hr)	1,238.2	1,136.5	1,114.3	1,096.8	1,044.8
Natural Gas (lb/hr)	62,854.8	57,691.8	56,565.2	55,672.6	53,037.5
(cf/hr)	1,303,410	1,196,346	1,172,983	1,154,474	1,099,829
Fuel:					
Heat Content, LHV (Btu/lb)	19,700	19,700	19,700	19,700	19,700
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,913,170	1,830,092	1,811,447	1,796,734	1,752,347
Volume Flow (scfm)	635,317	607,729	601,537	596,651	581,911
Mass Flow (lb/hr)	2,818,340	2,684,320	2,652,890	2,623,320	2,559,380
Temperature (oF)	1,130	1,130	1,130	1,130	1,130
Moisture (% Vol.)	7.25	8.28	8.62	9.42	9.24
Oxygen (% Vol.)	13.01	13.07	13.06	12.94	13.12
Molecular Weight	28.49	28.37	28.33	28.24	28.25
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack (without duct burner):					
Volume Flow (acfm)	794,146	759,661	751,922	745,814	727,389
Temperature (oF)	200	200	200	200	200
Diameter (ft)	18.0	18.0	18.0	18.0	18.0
Velocity (ft/sec)	52.0	49.8	49.2	48.8	47.6
Stack Height (ft)	180	180	180	180	180

Source: Westinghouse, 1992.

Table A-25A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
Hours of Operation	8460	8460	8460	8460	8460
Particulate					
Basis, lb/hr (1)	4.90	4.70	4.70	4.60	4.50
lb/hr	4.90	4.70	4.70	4.60	4.50
TPY	20.73	19.88	19.88	19.46	19.04
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	3.72	3.42	3.35	3.30	3.14
TPY	15.75	14.46	14.18	13.95	13.29
Nitrogen Oxides					
Basis, ppm* (1)	26.5	25.0	25.0	25.0	25.0
lb/hr	130.0	112.5	110.2	108.5	103.3
TPY	550.04	475.84	466.27	458.87	436.90
Carbon Monoxide					
Basis, ppm+ (1)	10.0	10.3	10.4	10.2	10.2
lb/hr	25.7	25.0	25.0	24.0	23.5
TPY	108.66	105.87	105.72	101.65	99.34
VOCs (as methane)					
Basis, ppm+ (1)	4.1	4.3	4.4	4.5	4.0
lb/hr	6.02	5.97	6.02	6.06	5.26
TPY	25.46	25.26	25.49	25.63	22.26
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Source: Westinghouse, 1992.

Table A-26A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	8	8	8	8	8
Mist	lb/hr	4.80E-01	4.41E-01	4.32E-01	4.25E-01	4.05E-01
	TPY	2.03E+00	1.86E+00	1.83E+00	1.80E+00	1.71E+00

Source: EPA, 1990

Table A-27A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant	Units	Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.38E-03	1.26E-03	1.24E-03	1.22E-03	1.16E-03
Matter	TPY	5.83E-03	5.35E-03	5.25E-03	5.16E-03	4.92E-03
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	1.09E-01	1.00E-01	9.82E-02	9.66E-02	9.21E-02
	TPY	4.62E-01	4.24E-01	4.15E-01	4.09E-01	3.89E-01
Carbon	% Exhaust Gas	3.62	3.47	3.43	3.41	3.33
Dioxide	lb/hr	1.58E+05	1.44E+05	1.41E+05	1.39E+05	1.33E+05
	TPY	6.67E+05	6.11E+05	5.98E+05	5.90E+05	5.62E+05

Source: (1) EPA, 1990

Table A-28A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 70 Percent Load

Pollutant		Gas Turbine Natural Gas 27oF	Gas Turbine Natural Gas 64oF	Gas Turbine Natural Gas 72oF	Gas Turbine Natural Gas 79oF	Gas Turbine Natural Gas 97oF
A		B	C	D	E	F
Antimony	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Barium	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cobalt	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Zinc	pg/J	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chlorine	ppm	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.

Table A-29A. Design Information for DESTEC Central Florida Cogeneration Facility-
Duct Burner, Supplemental Firing, Natural Gas

Data	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	100.0	100.0	100.0	100.0	100.0
Natural Gas (lb/hr)	4,194.8	4,194.8	4,194.8	4,194.8	4,194.8
(cf/hr)	105,263	105,263	105,263	105,263	105,263
Fuel:					
Heat Content, LHV (Btu/lb)	23,839	23,839	23,839	23,839	23,839
(Btu/cf)	950	950	950	950	950
DB Exhaust:					
Volume Flow (acfm)	1,504	1,504	1,504	1,504	1,504
Volume Flow (scfm)	1,203	1,203	1,203	1,203	1,203
Mass Flow (lb/hr)	5,244	5,244	5,244	5,244	5,244
Temperature (oF)	200	200	200	200	200
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	NA	NA	NA	NA	NA
Temperature (oF)	NA	NA	NA	NA	NA
Diameter (ft)	NA	NA	NA	NA	NA
Velocity (ft/sec)	NA	NA	NA	NA	NA
Stack Height (ft)	NA	NA	NA	NA	NA

Source: Destec Engineering, Inc., 1992

Table A-30A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
Hours of Operation	8760	8760	8760	8760	8760
Particulate					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	1.00	1.00	1.00	1.00	1.00
TPY	4.38	4.38	4.38	4.38	4.38
Sulfur Dioxide					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.32	1.32	1.32	1.32	1.32
Nitrogen Oxides					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
Carbon Monoxide					
Basis, lb/MMBtu	0.10	0.10	0.10	0.10	0.10
lb/hr	10.00	10.00	10.00	10.00	10.00
TPY	43.80	43.80	43.80	43.80	43.80
VOCs					
Basis, lb/MMBtu	0.029	0.029	0.029	0.029	0.029
lb/hr	2.90	2.90	2.90	2.90	2.90
TPY	12.70	12.70	12.70	12.70	12.70
Lead					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

Table A-31A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid Mist	% of SO2	8	8	8	8	8
	lb/hr	3.88E-02	3.88E-02	3.88E-02	3.88E-02	3.88E-02
	TPY	1.70E-01	1.70E-01	1.70E-01	1.70E-01	1.70E-01

Source: EPA, 1990

Table A-32A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-Duct Burner, Supplemental Firing, Natural Gas

Pollutant	Units	Natural Gas 27oF	Natural Gas 64oF	Natural Gas 72oF	Natural Gas 79oF	Natural Gas 97oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polycyclic	lb/10E+12 Btu (1)	1.113	1.113	1.113	1.113	1.113
Organic	lb/hr	1.11E-04	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Matter	TPY	4.87E-04	4.87E-04	4.87E-04	4.87E-04	4.87E-04
Formaldehyde	lb/10E+12 Btu (1)	88.12	88.12	88.12	88.12	88.12
	lb/hr	8.81E-03	8.81E-03	8.81E-03	8.81E-03	8.81E-03
	TPY	3.86E-02	3.86E-02	3.86E-02	3.86E-02	3.86E-02
Carbon	% Exhaust Gas	3.74	3.68	3.66	3.65	3.6
Dioxide	lb/hr	3.08E+02	3.03E+02	3.02E+02	3.01E+02	2.97E+02
	TPY	1.35E+03	1.33E+03	1.32E+03	1.32E+03	1.30E+03

Source: (1) EPA, 1990

Table A-33A. Maximum Emissions for Criteria Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant	Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Hours of Operation		300			8460			8760				
Particulate:												
lb/hr	34.20	30.80	29.20	4.90	4.70	4.50	1.00	1.00	1.00	35.20	31.80	30.20
TPY	5.13	4.62	4.38	20.73	19.88	19.04	4.38	4.38	4.38	30.24	28.88	27.80
Sulfur Dioxide:												
lb/hr	75.95	68.00	64.01	3.72	3.35	3.14	0.30	0.30	0.30	76.25	68.30	64.31
TPY	11.39	10.20	9.60	15.75	14.18	13.29	1.32	1.32	1.32	28.46	25.69	24.21
Nitrogen Oxides:												
lb/hr	240.01	203.12	191.00	130.03	110.23	103.29	10.00	10.00	10.00	250.01	213.12	201.00
TPY	36.00	30.47	28.65	550.04	466.27	436.90	43.80	43.80	43.80	629.84	540.54	509.35
Carbon Monoxide:												
lb/hr	141.97	127.98	121.02	25.69	24.99	23.48	10.00	10.00	10.00	151.97	137.98	131.02
TPY	21.30	19.20	18.15	108.66	105.72	99.34	43.80	43.80	43.80	173.76	168.72	161.29
VOCs (as methane):												
lb/hr	16.06	15.07	14.11	6.02	6.02	5.26	2.90	2.90	2.90	18.96	17.97	17.01
TPY	2.41	2.26	2.12	25.46	25.49	22.26	12.70	12.70	12.70	40.57	40.45	37.08
Lead:												
lb/hr	1.19E-02	1.06E-02	9.93E-03	NA	NA	NA	NA	NA	NA	1.19E-02	1.06E-02	9.93E-03
TPY	1.78E-03	1.59E-03	1.49E-03	NA	NA	NA	NA	NA	NA	1.78E-03	1.59E-03	1.49E-03

Table A-34A. Maximum Emissions of Other Regulated Pollutants for DETEC Central Florida Cogeneration Facility
Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Arsenic													
	lb/hr	5.59E-03	4.99E-03	4.69E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.59E-03	4.99E-03	4.69E-03
	TPY	8.39E-04	7.48E-04	7.03E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	8.39E-04	7.48E-04	7.03E-04
Beryllium													
	lb/hr	3.33E-03	2.97E-03	2.79E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.33E-03	2.97E-03	2.79E-03
	TPY	5.00E-04	4.45E-04	4.19E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.00E-04	4.45E-04	4.19E-04
Mercury													
	lb/hr	4.00E-03	3.56E-03	3.35E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.00E-03	3.56E-03	3.35E-03
	TPY	5.99E-04	5.35E-04	5.02E-04	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.99E-04	5.35E-04	5.02E-04
Fluoride													
	lb/hr	4.33E-02	3.87E-02	3.63E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.33E-02	3.87E-02	3.63E-02
	TPY	6.50E-03	5.80E-03	5.45E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.50E-03	5.80E-03	5.45E-03
Sulfuric Acid Mist	lb/hr	9.30E+00	8.33E+00	7.84E+00	4.80E-01	4.32E-01	4.05E-01	3.88E-02	3.88E-02	3.88E-02	9.34E+00	8.37E+00	7.88E+00
	TPY	1.40E+00	1.25E+00	1.18E+00	2.03E+00	1.83E+00	1.71E+00	1.70E-01	1.70E-01	1.70E-01	3.60E+00	3.25E+00	3.06E+00

W501FTOT
6/12/92

Table A-35A. Maximum Emissions of Non-Regulated Pollutants for DESTEC Central Florida Cogeneration Facility-
Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Manganese	lb/hr	1.86E-02	1.66E-02	1.56E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.86E-02	1.66E-02	1.56E-02
	TPY	2.80E-03	2.49E-03	2.34E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.80E-03	2.49E-03	2.34E-03
Nickel	lb/hr	2.26E-01	2.02E-01	1.90E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.26E-01	2.02E-01	1.90E-01
	TPY	3.40E-02	3.03E-02	2.85E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.40E-02	3.03E-02	2.85E-02
Cadmium	lb/hr	1.40E-02	1.25E-02	1.17E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.40E-02	1.25E-02	1.17E-02
	TPY	2.10E-03	1.87E-03	1.76E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	2.10E-03	1.87E-03	1.76E-03
Chromium	lb/hr	6.33E-02	5.64E-02	5.30E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	6.33E-02	5.64E-02	5.30E-02
	TPY	9.49E-03	8.46E-03	7.95E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.49E-03	8.46E-03	7.95E-03
Copper	lb/hr	3.73E-01	3.33E-01	3.13E-01	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.73E-01	3.33E-01	3.13E-01
	TPY	5.59E-02	4.99E-02	4.69E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	5.59E-02	4.99E-02	4.69E-02
Vanadium	lb/hr	9.26E-02	8.26E-02	7.76E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	9.26E-02	8.26E-02	7.76E-02
	TPY	1.39E-02	1.24E-02	1.16E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	1.39E-02	1.24E-02	1.16E-02
Selenium	lb/hr	3.12E-02	2.78E-02	2.61E-02	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	3.12E-02	2.78E-02	2.61E-02
	TPY	4.68E-03	4.17E-03	3.92E-03	NEG.	NEG.	NEG.	NEG.	NEG.	NEG.	4.68E-03	4.17E-03	3.92E-03
Polycyclic Organic Matter	lb/hr	3.70E-04	3.30E-04	3.10E-04	1.38E-03	1.24E-03	1.16E-03	1.11E-04	1.11E-04	1.11E-04	1.49E-03	1.35E-03	1.27E-03
	TPY	5.55E-05	4.95E-05	4.65E-05	5.83E-03	5.25E-03	4.92E-03	4.87E-04	4.87E-04	4.87E-04	6.37E-03	5.78E-03	5.45E-03
Formaldehyde	lb/hr	5.39E-01	4.81E-01	4.52E-01	1.09E-01	9.82E-02	9.21E-02	8.81E-03	8.81E-03	8.81E-03	5.48E-01	4.90E-01	4.61E-01
	TPY	8.09E-02	7.22E-02	6.78E-02	4.62E-01	4.15E-01	3.89E-01	3.86E-02	3.86E-02	3.86E-02	5.81E-01	5.26E-01	4.96E-01
Carbon Dioxide	lb/hr	2.32E+05	2.07E+05	1.95E+05	1.58E+05	1.41E+05	1.33E+05	3.08E+02	3.02E+02	2.97E+02	2.33E+05	2.08E+05	1.95E+05
	TPY	3.49E+04	3.11E+04	2.92E+04	6.67E+05	5.98E+05	5.62E+05	1.35E+03	1.32E+03	1.30E+03	7.03E+05	6.30E+05	5.92E+05

Table A-36A. Maximum Emissions for Additional Non-Regulated Pollutant for DESTEC Central Florida Cogeneration Facility- Westinghouse 501F, Dry Low NOx Combustor, 70 Percent Load and Duct Burner

Pollutant		Gas Turbine- Distillate Oil			Gas Turbine- Natural Gas			Duct Burner- Natural Gas			Maximum Emissions		
		27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF	27 oF	72 oF	97 oF
Antimony													
	lb/hr	2.91E-02	2.60E-02	2.44E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.91E-02	2.60E-02	2.44E-02
	TPY	4.36E-03	3.89E-03	3.66E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	4.36E-03	3.89E-03	3.66E-03
Barium													
	lb/hr	2.60E-02	2.32E-02	2.18E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	2.60E-02	2.32E-02	2.18E-02
	TPY	3.90E-03	3.48E-03	3.27E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.90E-03	3.48E-03	3.27E-03
Cobalt													
	lb/hr	1.21E-02	1.08E-02	1.01E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.21E-02	1.08E-02	1.01E-02
	TPY	1.81E-03	1.62E-03	1.52E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.81E-03	1.62E-03	1.52E-03
Zinc													
	lb/hr	9.10E-01	8.12E-01	7.63E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	9.10E-01	8.12E-01	7.63E-01
	TPY	1.37E-01	1.22E-01	1.14E-01	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	1.37E-01	1.22E-01	1.14E-01
Chlorine													
	lb/hr	3.68E-02	3.28E-02	3.08E-02	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	3.68E-02	3.28E-02	3.08E-02
	TPY	5.52E-03	4.92E-03	4.62E-03	NEG.	NEG.	NEG.	0.00E+00	0.00E+00	0.00E+00	5.52E-03	4.92E-03	4.62E-03

EXAMPLE CALCULATIONS

DESTEC CENTRAL FLORIDA COGENERATION PROJECT

EXAMPLE CALCULATIONS - 27°F CONDITIONS

(From Table A-1 On Distillate Oil;
All Other Calculations on Spreadsheet are Identical.)

Table A-1: (Note: all other data not calculated but supplied by Manufacturer)

Heat Input (10^6 Btu/hr):

Power (kW) x Heat Rate (10^6 Btu/kWh)

$183{,}700 \times 10{,}070/10^6 = 1{,}849.9 \times 10^6$ Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

$1{,}849.9 \times 10^6 \div 18{,}550 = 99{,}723$ lb/hr

Volume Flow (acfm) - See Note A:

$V = mRT/PM$

$3{,}743{,}000$ lb/hr $\times 1{,}545 \times (1{,}060°F + 460°F) \div (28.25 \times 2{,}116.8$ lb/ft$^2)$

$\div$ 60(min/hr)

= 2,450,287 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

$3{,}743{,}000$ lb/hr $\times 1{,}545 \times (68°F + 460°F) \div (28.25 \times 2{,}116.8) \div 60$

= 851,152 scfm

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

2,450,287 acfm x (205°F + 460°F) ÷ (1,060°F + 460°F)

= 1,072,001 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

1,072,001 ft^3/min ÷ 60 ÷ (18.0^2 ÷ 4 x 3.14159)

= 70.2 ft/sec

<u>Table A-2</u>:

PM emissions in tons per year

17 lb/hr x 300 hr/yr ÷ 2,000 lb/ton

= 2.6 ton/yr

SO_2 Emissions--Oil (lb/hr)

99,722.9 lb/hr x 0.0005 lb S/lb x 2 lb SO_2/lb S

= 99.72 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 x (1 - 11.59/100) - 10.96] x 2,116.8 lb/ft^2
x 2,450,287 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (1,060°F + 460°F)
x 5.9 x 10^6 (adjust for ppm)]

= 326.2 lb/hr

CO Emissions (lb/hr) - See Note C:

30 ppm x (1 - 11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10^6)

= 98.4 lb/hr

VOC Emissions (lb/hr) - See Note C:

3.5 ppm x (1-11.59/100) x 2,450,287 acfm x 2,116.8 lb/ft^2 x 16 (molecular wgt. of methane)

x 60 min/hr ÷ (1,545 x (1,060°F + 460°F) x 10^6)

= 6.56 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x 1,849.9 x 10^6 Btu/hr = 1.65 x 10^{-2} lb/hr

<u>Table A-3</u>:

H_2SO_4 Mist Emissions (lb/hr):

Based on 8 percent of sulfur converted to acid mist

99,722.9 lb/hr x 0.0005 lb S/lb x 3.06 lb H_2SO_4/lb S x 0.05 (converted)

= 12.2 lb/hr

<u>Tables A-4 and A-5</u>:

EPA emission factor as noted in printout; example for manganese:

1,849.9 (MMBtu) x 14 lb/10^{12} Btu

= 2.59 x 10^{-2} lb/hr

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT/M$$

where:
- P = pressure = 2116.8 lb/ft^2
- m = mass flow of gas (lb/hr)
- R = universal gas constant = 1545
- M = molecular weight of gas
- T = temperature (°R)

NOTE B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

(From 40 CFR Part 60; Appendix A, Method 20, Equation 20-4)

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

(From Method 20; Equation 20-1)

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O);\ \text{(From Method 20; Equation 20-1)}$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$\begin{aligned} m_{CO} &= PV_{CO\ Act}M_{CO}\ /\ RT \\ &= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT \end{aligned}$$

EMISSION FACTORS

PB91-126003

United States
Environmental Protection
Agency

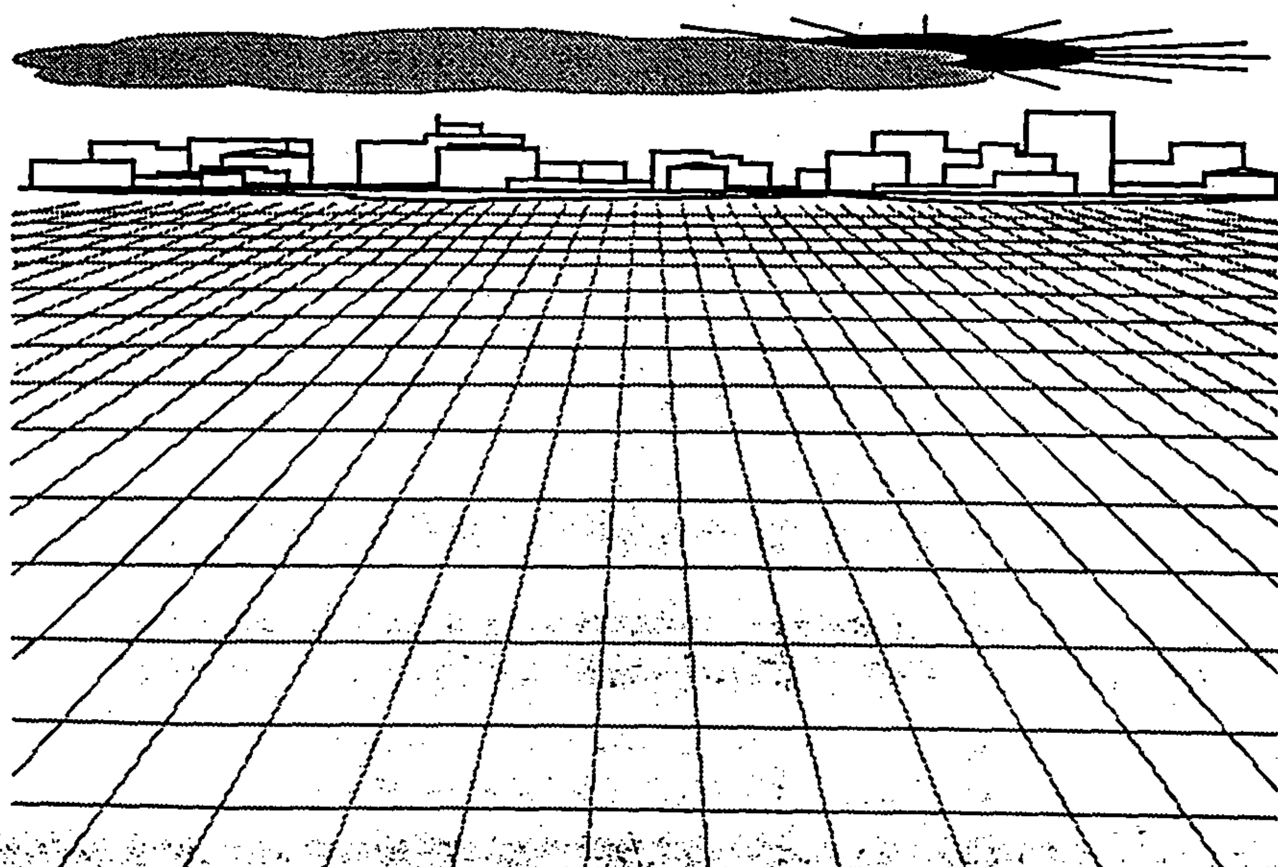
Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-90-011
October 1990

AIR

EPA

TOXIC AIR POLLUTANT EMISSION FACTORS - A COMPILATION FOR SELECTED AIR TOXIC COMPOUNDS AND SOURCES, SECOND EDITION



INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Nonferrous metals production	3341	Melt furnace at permanent magnet alloy facility	304	Nickel	7440020	2 lb/ton of nickel charged	Controlled by fabric filter, based on engineering judgement	118
Nonferrous metals production	3341	Melt furnace at superalloy facility	304	Nickel	7440020	2 lb/ton of nickel charged	Controlled by fabric filter, based on engineering judgement	118
Nonylphenol production	2869	Fugitive emissions	301	Phenol	108952	0.38 lb/ton used	From engineering estimates	13
Nonylphenol production	2869	General emissions	301	Phenol	108952	1.6 lb/ton used	From engineering estimates	13
Nonylphenol production	2869	Storage	407004	Phenol	108952	0.02 lb/ton used	From engineering estimates	13
Oil and coal combustion	49	Stack - particulate	102	Polychlorinated dibenzo-p-dioxins, total		1.36 x 10E-4 lb/ton	No penta homologue included, one location, TCDD detection = 4 x 10E-5 lb/ton	119
Oil and coal combustion	49	Stack - particulate	102	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1746016	Not detectable	One location, detection limit = 2 x 10E-6 lb/ton	119
Oil combustion		Fuel oil		Ammonia	7664417	0.8 lb/1000 gallons fuel oil burned	Sources emitting > 100 tons NH3/year	179
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	2.06 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	0.50 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	0.42 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	19 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	9.31 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	2.28 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Arsenic	7440382	1.90 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	2.5 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	1.58 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.35 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.15 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	2.65 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.59 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Beryllium	7440417	0.25 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	10.5 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36

INDUSTRIAL/PROCESS CATEGORY	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	7.45 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	1.58 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	0.63 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	15.7 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	44.86 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	9.90 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Cadmium	7440439	3.94 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	47.5 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	27.8 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	13.92 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	3.84 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	21 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	12.18 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	6.09 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Chromium	7440473	1.68 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	280 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	145.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	42 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	278 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	145.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired	1	Copper	7440508	[illegible] lb/10E12 Btu	Controlled with ESP, calculated based [illegible]	[illegible]

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Oil-fired boiler or furnace, util/commerc/industr/residential	1	Formaldehyde	50000	405 lb/10E12 Btu	Uncontrolled, based on emissions testing	34
Oil combustion		Industrial, commercial, and residential boilers	1	Lead	7439921	8.9 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use distillate oil	34
Oil combustion		Utility boiler	101004	Lead	7439921	28 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use residual oil	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	14 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	6.44 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	3.08 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	1.54 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	26 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	11.96 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	5.72 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	34

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INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Manganese	7439965	2.84 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.0 lb/10E12 Btu	Uncontrolled, based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.0 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	2.25 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	0.78 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.2 lb/10E12 Btu	Uncontrolled, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.2 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	2.4 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	34
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	0.83 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	34
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Nickel	7440020	170 lb/10E12 Btu	Uncontrolled, based on engineering judgement	34
Oil combustion		Distillate oil-fired	1	Nickel	7440020	84.7 lb/10E12 Btu	Controlled by multiclone, based on engineering	[illegible]

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion, commercial		Tangential furnace, distillate oil	103005	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Tangential furnace, residual oil	103004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, distillate oil	103005	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, residual oil	103004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired tangential furnaces	103005	Vanadium	7440622	69.5 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired wall furnaces	103005	Vanadium	7440622	69.5 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Residual oil-fired tangential furnaces	103004	Vanadium	7440622	8487 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Residual oil-fired wall furnaces	103004	Vanadium	7440622	8487 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Oil-fired boiler	102005	Lead	7439921	0.00015 lbs/10E6 BTU heat input	Uncontrolled emissions, based on 1 test	189
Oil combustion, industrial		Steam atomized watertube, residual oil	10200401	Polycyclic organic matter		5.33 lb/10E12 Btu heat input	Uncontrolled, represents mostly particulate POM	114
Oil combustion, industrial		Watertube, residual oil	10200401	Polycyclic organic matter		1.46 lb/10E12 Btu heat input	Uncontrolled, represents both gaseous and particulate POM	114
Oil combustion, industrial		Tangential furnace	102	Selenium	7782492	4.63 lb/10E12 Btu	Controlled by scrubber, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Tangential furnace	102	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Selenium	7782492	4.43 lb/10E12 Btu	Controlled by scrubber, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Tangential furnace	102	Vanadium	7440622	402.9 lb/10E12 Btu	Controlled by scrubber, based on reported emissions and engineering judgement	54

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion, industrial		Wall furnace	102	Vanadium	7440622	602.9 lb/10E12 Btu	Controlled by scrubber, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Vanadium	7440622	3014 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, residential		Distillate oil-fired furnaces		Selenium	7782492	4.72 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, residential		Distillate oil-fired boiler, util/commerc/industr/residential		Vanadium	7440622	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility		Face-fired, residual oil	10100401	Polycyclic organic matter		0.858 lb/10E12 Btu heat input	Uncontrolled, represents both gaseous and particulate POM	114
Oil combustion, utility		Tangential-fired, residual oil	10100404	Polycyclic organic matter		5.79 lb/10E12 Btu heat input	Cyclone controls, represents both gaseous and particulate POM	114
Oil combustion, utility		Wall-fired, residual oil	10100401	Polycyclic organic matter		9.04 lb/10E12 Btu heat input	Uncontrolled, ave. of 4 values ranging from 0.45-12.3 pg/J, represents gaseous & particulate POM	114
Oil combustion, utility	491	Oil-fired utility boiler	101004	Sulfuric acid	7664939	8.5 x % sulfur in fuel ng/J	Controlled emissions, FGD system with 50% efficiency for sulfuric acid mist	213
Oil combustion, utility	491	Oil-fired utility boiler	101004	Sulfuric acid	7664939	16.9 x % sulfur in fuel ng/J	Uncontrolled emissions	213
Oil combustion, utility	4911	Tangential-fired, residual oil	101004	Selenium	7782492	4.638 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Tangential-fired, residual oil	101004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Wall furnace, residual oil	101004	Selenium	7782492	4.638 lb/10E12 Btu	Controlled by ESP, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Wall furnace, residual oil	101004	Selenium	7782492	23.42 lb/10E12 Btu	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired tangential furnaces	101004	Vanadium	7440622	702.6 lb/10E12 Btu	Controlled by ESP, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired tangential furnaces	101004	Vanadium	7440622	3515 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired wall furnaces	101004	Vanadium	7440622	702.6 lb/10E12 Btu	Controlled by ESP, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired wall furnaces	101004	Vanadium	7440622	3515 lb/10E12 Btu	Uncontrolled, based on reported emissions and engineering judgement	54

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil shale retorting	1311	Entire process		Mercury	7439976	2.2 x 10E-4 lbs/barrel oil produced	Includes Hg compound form, assumes fac. using 13,000 tons/day raw shale to prod. 12,000 bbl/day oil	40
Oil shale retorting	1311	Modified in situ retort		Polycyclic organic matter		0.0073 lb/hr	Based on offgas concentration and flow rate	114
Open burning		Area source	50300201	Acetaldehyde	75070	0.72 - 1.46 lb/ton wood burned	Estimated from a total aldehyde value of 10.4 lb/ton	130
Open burning		Automobile body burning	50300203	Polycyclic organic matter		0.22 lb/ton waste	Based on concentration measured in smoke plume	114
Open burning		Automobile tire burning	50300203	Polycyclic organic matter		0.48 lb/ton waste	Based on concentration measured in smoke plume	114
Open burning		Grass, leaves, branches	50300201	Polycyclic organic matter		0.005 - 0.0184 lb/ton waste	Based on concentration measured in smoke plume	114
Open burning		Leaf burning	50300201	Polycyclic organic matter		0.02 - 0.044 lb/ton leaves	Based on lab tests	114
Open burning		Municipal refuse open burning	50300202	Polycyclic organic matter		0.001 - 0.0094 lb/ton waste	Based on concentration measured in smoke plume	114
Oxybisphenoxarsine and 1,3-diisocyanate production	2899	Desorption of aqueous waste		Chloroform	67663	0.0022 lb/s	Uncontrolled	160
Oxybisphenoxarsine production	2899	Plantwide emissions		Chloroform	67663	0.0018 lb/s	Carbon adsorption	160
Paint and coating application		Entire process	402	Tetrachloroethylene	127184	2000 lb/ton PCE in paint or coating appl	Uncontrolled, based on engineering judgement	68
Paint and coating application		Entire process	40200101	Toluene	108883	2000 lb/ton used	Assume all toluene is eventually released to atmosphere	13
Paint and coating application		Entire process	402	Trichloroethylene	79016	2000 lb/ton TCE in paint or coating appl	Uncontrolled, based on engineering judgement	105
Paint and coating application	1721	End use	402	Xylenes (mixed isomers)	1330207	2000 lb/ton xylene consumed	Engineering judgement	77
Paint and coating manufacture	28	Xylene solvent	301014	Xylenes (mixed isomers)	1330207	40.4 lb/ton xylene consumed		67
Paint application		Entire process	402	Mercury	7439976	1310 lb/ton of contained Hg	Uncontrolled, based on engineering judgement	113
Paint application		Coating application of solvent-based paints	40200101	Xylenes (mixed isomers)	1330207	1740 lb/ton xylene used	Estimated	13

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Municipal waste combustion	4953	Mass burn waterwall combustor, small size new model to any age medium	501001	Tetrachlorodibenzo-p-dioxins, total		3.2 x 10E-8 lb/ton feed	Capacity < 600 tons/day, ESP control only, overall average of several source averages, range is 1.26 x 10E-8 - 5.2 x 10E-8 lb/ton	180
Municipal waste combustion	4953	Mass burn waterwall combustor, small size new model to any age medium	501001	Tetrachlorodibenzo-p-dioxins, total		0.74 ug/Mg feed	Capacity < 600 tons/day, spray drying after acid gas and PM control, one data point only	180
Municipal waste combustion	4953	Mass burn waterwall combustor, small size new model to any age medium	501001	Tetrachlorodibenzo-p-dioxins, total		2.0 x 10E-8 lb/ton feed	Capacity < 600 tons/day, dry sorbent injection after acid gas and PM control, range is 1.08 x 10E-8 - 2.4 x 10E-8 lb/ton	180
Municipal waste combustion	4953	Mass burn waterwall combustor, built before 1980	501001	Tetrachlorodibenzo-p-dioxins, total		2.8 x 10E-6 lb/ton feed	ESP control only, overall average of several source averages, range is 6.4 x 10E-8 - 6.0 x 10E-6 lb/ton	180
Municipal waste combustion	4953	Mass burn, refractory facility	501001	Tetrachlorodibenzo-p-dioxins, total		3.4 x 10E-6 lb/ton feed	ESP control only, overall average of several source averages, range is 3.0 x 10E-6 - 3.6 x 10E-6 lb/ton	180
Municipal waste combustion	4953	Incinerator stack	501001	Zinc	7440666	1.0 lb/ton munic. solid waste-dry wt.	Controlled by spray-baffle scrubber, based on material balance for model incinerator	98
Naphthalene production		Process emissions		Naphthalene	91203	0.478 lb/ton naphthalene produced	Based on POM emissions and 87% naphthalene	99
Naphthalene production		Storage		Naphthalene	91203	0.0454 lb/ton produced	Based on data from State files and engineering judgement	99
Natural gas combustion		Commercial boiler	10300601	Ammonia	7664417	0.49 lb/10E6 cubic feet gas burned	Sources emitting > 100 tons NH3/year	179
Natural gas combustion		Industrial boilers	10200601	Ammonia	7664417	3.2 lbs/10E6 cubic feet gas burned	Sources emitting > 100 tons NH3/year	179
Natural gas combustion		Boilers, exhaust system	102006	Benzene	71432	1.18% by vol (or 4% by wt) of total VOC	South Coast study, California, engineering judgement	132
Natural gas combustion		Commercial/institutional	103006	Formaldehyde	50000	220.3 lb/10E12 Btu heat input	Control status unspecified, based on source tests	106
Natural gas combustion		Domestic		Formaldehyde	50000	997 lb/10E12 Btu heat input	Control status unspecified, based on source tests	106
Natural gas combustion		Industrial	102006	Formaldehyde	50000	88.12 lb/10E12 Btu heat input	Control status unspecified, based on source tests	106
Natural gas combustion		Double shell boilers, home heating		Polycyclic organic matter		1.113 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion		Firetube boiler, process heater	10200601	Polycyclic organic matter		0.449 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC CODE	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Natural gas combustion		Hot air furnace, home heating		Polycyclic organic matter		0.768 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion		Scotch marine, hospital heating	10200601	Polycyclic organic matter		43.5 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion		Wall space heater, home heating		Polycyclic organic matter		43.77 lb/10E12 Btu heat input	Represents primarily particulate POM, uncontrolled	114
Natural gas combustion	49	Utility boiler	10100601	Ammonia	7664417	3.2 lbs/10E6 cubic feet gas burned	Sources emitting > 100 tons NOX/year, emission factor rating C	179
Natural gas combustion - commercial/institutional		Tangential or wall-fired boiler	103006	Mercury	7439976	11.343 lb/10E12 Btu	Uncontrolled emissions	212
Natural gas combustion - utility	491	Tangential-fired boiler	10100604	Mercury	7439976	2.27 lb/10E12 Btu	Controlled emissions, wet scrubber at 80% efficiency for Hg	212
Natural gas combustion - utility	491	Wall-fired boiler	10100601	Mercury	7439976	2.272 lb/10E12 Btu	Controlled emissions, wet scrubber at 80% efficiency for Hg	212
Natural gas combustion - utility	491	Tangential-fired boiler	10100604	Mercury	7439976	11.343 lb/10E12 Btu	Uncontrolled emissions, based on stack tests	212
Natural gas combustion - utility	491	Wall-fired boiler	10100601	Mercury	7439976	11.343 lb/10E12 Btu	Uncontrolled emissions, based on stack tests	212
Neoprene manufacture	2822	Dichlorobutene refining	301	1,3-Butadiene	106990	3.12 lb/ton neoprene produced	Calculated from national emissions and national capacity, mostly controlled	78
Neoprene manufacture	2822	Dichlorobutene synthesis	301	1,3-Butadiene	106990	0.6 lb/ton neoprene produced	Calculated from national emissions and national capacity, mostly controlled	78
Neoprene manufacture	2822	Equipment leak	301	1,3-Butadiene	106990	2.2 lb/ton neoprene produced	Uncontrolled, calculated from national emissions and national capacity	78
Neoprene manufacture	2822	Jet vent scrubber	301026	1,3-Butadiene	106990	0.094 lb/ton neoprene produced	Engineering judgement	123
Neoprene manufacture	2822	Equipment leak	301018	1,3-Butadiene	106990	2.954 tons/yr	Uncontrolled, average emission factor based on 2 facilities	166
Neoprene manufacture	2822	Process vents	301018	1,3-Butadiene	106990	2.226 tons/yr	Controlled (unspecified), average emission factor based on 2 facilities	166
Neoprene manufacture	2822	Process vents	301018	1,3-Butadiene	106990	12.280 lb/ton	Uncontrolled, average emission factor based on 2 facilities	166
Neoprene manufacture	2822	Batch polykettles	301026	Chloroprene	126998	2.1 lb/ton neoprene	Engineering judgement	123
Neoprene manufacture	2822	Blend tanks	30102614	Chloroprene	126998	0.32 lb/ton neoprene	Engineering judgement	133

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Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
Element	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.8	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149
Iron (Fe)	363	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

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Emission Assessment of Conventional Stationary Combustion Systems; Volume II Internal Combustion Sources

TRW, Inc, Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

Feb 1979

TABLE 52. COMPARISON OF TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FUELED GAS TURBINES AND DISTILLATE OIL ENGINES

Trace Element	Mean Emission Factor, pg/J	
	Distillate Oil Fueled Gas Turbine	Distillate Oil Reciprocating Engine
Aluminum	64	66
Antimony	9.4	12
Arsenic	2.1	2.2
Barium	8.4	14
Beryllium	0.14	0.03
Boron	28	11
Bromine	1.8	4.0
Cadmium	1.8	3.1
Calcium	330	237
Chromium	20	26
Cobalt	3.9	5.7
Copper	578	453
Iron	256	325
Lead	25	26
Magnesium	100	44
Manganese	145	16
Mercury	0.39	0.13
Molybdenum	3.6	12.5
Nickel	526	564
Phosphorus	127	97
Potassium	185	179
Selenium	2.3	2.1
Silicon	575	301
Sodium	590	1625
Tin	35	9.1
Vanadium	1.9	0.95
Zinc	294	178

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Environmental Protection
Agency

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

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu) Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

APPENDIX B
CONTROL TECHNOLOGY REVIEW

B.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS regulations applicable to gas turbines apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the proposed project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.06 percent, the NSPS is increased by 0.0024 percent or 24 parts per million (ppm).

The applicable NSPS for the duct burner is codified in 40 CFR Part 60 Subpart Dc. Table B-2 presents a summary of the NSPS limits. There are no quantifiable emission limits for natural gas firing.

Table B-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.
[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

Table B-2. Summary of NSPS for Small Industrial-Commercial-Institutional Steam Generating Units

Unit Size (heat input)	Fuel	Annual Capacity Factor	Emission Standard
		PARTICULATE MATTER	
30-100 MMBtu/hr	Coal; Coal w/other fuels	>90% on coal	0.05 lb/MMBtu
		<90% on coal	0.10 lb/MMBtu
	Wood; Wood w/other fuels (except coal)	>30% on wood	0.10 lb/MMBtu
		<30% on wood	0.30 lb/MMBtu
	Oil	No limitation	No emission limit
		OPACITY	
30-100 MMBtu/hr	All fuels	No limitation	20% opacity
		SULFUR DIOXIDE	
>75 MMBtu/hr	Coal	>55% on coal	1.2 lb/MMBtu; 90% reduction
	Coal	<55% on coal	1.2 lb/MMBtu
	Coal w/emerging SO_2 control technology	>55% on coal	0.6 lb/MMBtu; 50% reduction
	Coal in duct burner of combined cycle system	No limitation	1.2 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu; 80% reduction
30-75 MMBtu/hr	Coal	No limitation	1.2 lb/MMBtu
	Coal w/emerging SO_2 control technology	No limitation	0.6 lb/MMBtu
	Coal in duct burner of combined cycle system	No limitation	0.6 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu

Source: 40 CFR Part 60 Subpart Dc.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

B.2.1 NITROGEN OXIDES

Advanced dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is technically feasible for the proposed project. The available information suggests that SCR with dry low-NO_x combustor technology or with wet injection is also technically feasible. Central Florida Power Limited Partnership believes that the advanced dry low-NO_x combustor is equivalent to the SCR technology and has several important advantages.

B.2.1.1 Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table B-3 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines. This table was developed from the information contained in the LAER/BACT clearinghouse documents (EPA, 1985b, 1986, 1987c, 1988c, 1989) and by contacting state agencies, such as the California Air Control Board, the South Coast Air Quality Management District, the New Jersey Department of Environmental Protection, and the Rhode Island Department of Environmental Management.

Historically, the most stringent NO_x controls for GTs established as LAER/BACT by state agencies were selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet

Table B-3. Summary of BACT Determinations for NOx from Gas-fired Turbines (Page 1 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NO_x Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	25 @ 15% O_2	Steam Injection	--
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	25 @ 15% O_2	Steam Injection	--
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	--	--	--	42 @ 15% O_2	Dry Low NO_x Combustor	--
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	--	6.3	--	40 ppmv @ 15% O_2	Water Inject 0.67 lb/lb	71.00%
City of Lakeland	FL	Jul-91	Combined Cycle	120 MW	--	--	--	25 @ 15% O_2	Dry Low NO_x Combustor	--
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	--	--	--	6 @ 15% O_2	SCR	90.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	--	--	--	25 @ 15% O_2	Dry Low NO_x Combustor	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	--	139	--	25	H2o Injection & Low NO_x Comb.	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	--	--	1032	42	Water Injection	--
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	--	--	--	42 @ 15% O_2	Wet Injection	--
Salinas River Cogen	CA	Nov-90	Gas Turbine	43.2 MW	--	10	--	6 @ 15% O_2	Dry Low NO_x Comb. & SCR	--
Sargent Canyon Cogen Co	CA	Nov-90	Gas Turbine	42.5 MW	--	10	--	6 @ 15% O_2	Dry Low NO_x Comb. & SCR	--
March Point Cogen	WA	Oct-90	Turbine	80 MW	--	--	--	25 @ 15% O_2	Massive Steam Injection	80.00%
Las Vegas Cogen	NV	Oct-90	Turbine, Peaking	397 MMBtu/hr	--	--	--	10 ppm	Water Injection & SCR	--
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	0.10	--	--	25 @ 15% O_2	Dry Low NO_x Combustor	--
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	--	--	--	9	Dry Comb. to 25 ppm, SCR to 9 ppm	--
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	--	--	--	36	Water Injection	--
O'Brian California Cogen II	CA	Jan-90	Gas Turbine	49.50 MW	--	114.6	--	--	SCR	--
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	--	--	--	9 @ 15% O_2, 1H Avg	Water Injection & SCR	80.00%
Richmond Power Enterprise Partn.	VA	Dec-89	Gas Turbine	1,163.5 MMBtu/hr	--	--	--	8.2 @ 15% O_2	Steam Inj. & SCR	--
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	--	--	--	25 ppm	Steam Injection	--
Badger Creek Limited	CA	Oct-89	GT-Cogen	457.8 MMBtu/hr	0.0135	--	--	--	Steam Injection & SCR	--
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	--	--	--	42 @ 15% O_2	Steam Injection	--
City of Anaheim GT Proj.	CA	Sep-89	Gas Turbine	442 MMBtu/hr	--	3.75	--	--	Steam Injection & SCR	69.60%
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.17	83	--	--	Water Injection	--
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	--	--	--	36 ppm	Water Injection	--
Cimarron Chemical Co.	CO	Aug-89	Turbines (2)	271.0 MMBtu/hr	--	--	--	65 ppmv @ 15% O_2	Steam Injection	--
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	--	--	--	42 ppm	Steam Injection	--
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	--	--	--	42 ppm	Water Injection	--
Potomac Electric Power Company	MD	Mar-89	Combined Cycle	860 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	--	--	--	42 @ 15% O_2	Water Injection	--

Table B-3. Summary of BACT Determinations for NOx from Gas-fired Turbines (Page 2 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NO_x Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
Pawtucket Power	RI	Jan-89	Turbine	58 MW	--	--	--	9 @ 15% O_2	SCR	--
L&J Energy System Cogen	NY	Jan-89	GE LM 5000	40 MW	--	--	--	42 ppm	Steam Injection	--
Mojave Cogen	CA	Jan-89	Turbine	490 MMBtu/hr	0.031	--	--	--	--	--
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	--	--	--	9 @ 15% O_2	Water Injection & SCR	--
Mojave Cogen	CA	Dec-88	Turbine	45 MW	--	--	--	10 ppm	Steam Injection & SCR	--
Champion International	AL	Nov-88	Gas Turbine	35 MW	--	--	--	42 @ 15% O_2	Steam Injection	70.00%
Indeck-Yerks Energy Services	NY	Nov-88	GE Frame 6	40 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	--	--	--	55 ppm	Water Injection	--
Amtrak	PA	Oct-88	Turbine (2)	20 MW	--	--	--	42 @ 15% O_2	H_2O Injection	--
Mobile Oil	CA	Sep-88	Turbine (2)	81.40 MMBtu/hr	0.047	3.78	--	--	Water Inj. & SCR	--
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	--	--	--	42 ppm	Steam Injection	--
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	--	--	--	42 @ 15% O_2	Steam Injection	--
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	--	--	--	42 ppm	Low NO_x Burners & Water Inj.	--
O'Brien Cogen	CT	Aug-88	Gas Turbine (2)	499.9 MMBtu/hr	--	--	--	39 @ 15% O_2	Water Injection	--
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	--	--	--	42 ppm	Steam Injection	--
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	--	--	--	42 @ 15% O_2, 1H Avg	H20 Injection	59.00%
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	--	--	--	36 @ 15% O_2	Water Injection	--
Merck Sharp & Pohme	PA	May-88	Turbine	310 MMBTU/hr	--	--	--	42 @ 15% O_2	Steam Injection	--
Virginia Power	VA	Apr-88	GE Turbine	1,875 MMBTU/hr	--	490		42 @ 15% O_2	Steam Injection	--
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.2	--	--	75 ppm	H_2O Inj. & Combustion Controls	--
Combined Energy Resources	CA	Feb-88	Gas Turbine	25.94 MW	--	199.0	--	--	H_2O Injection & SCR	81.00%
Texas Gas Transmission Corp.	KY	Feb-88	Gas Turbine	14300 HP	--	--	--	--	NO_x 0.015 % by Volume	--
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	--	--	--	42 @ 15% O_2	Steam Injection	--
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	--	85	--	--	Water Inj. & Quiet Combustion	--
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	--	--	--	42 @ 15% O_2	Water Injection	--
BAF Energy	CA	Jul-87	Turbine, Generator	887.2 MMBTU/hr	--	30.1	--	9 ppm @ 15% O_2	Steam Injection & SCR	80.00%
AES Placerita, Inc.	CA	Jul-87	Turbine	530 MMBTU/hr	--	14.2	--	9 @ 15% O_2	St./F Ratio 2.2:1 & SCR	--
AES Placerita, Inc.	CA	Jul-87	Gas Turbine	530	--	12.0	--	9 @ 15% O_2	St./F Ratio 2.2:1 & SCR	--
Simpson Paper Co.	CA	Jun-87	Gas Turbine	49.50 MW	--	9.71	--	6 @ 15% O_2	Steam Injection & SCR	--
Power Development Co.	CA	Jun-87	Gas Turbine	49 MMBTU/H	--	1.5	--	9 @ 15% O_2	H_2O Injection & SCR	--
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	--	10.4	--	6 @ 15% O_2	H_2O Injection & SCR	76.00%
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	--	--	--	9.6 @ 15% O_2	H^2O Injection & SCR	95.00%
Trunkline LNG	LA	May-87	Gas Turbine	147,102 SCF/hr	--	59	--	--	--	

Table B-3. Summary of BACT Determinations for NOx from Gas-fired Turbines (Page 3 of 3)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NO_x Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	--	50.3	--	154 Combustion Control	--	
Anheuser-Busch	FL	Apr-87	Gas Turbine	95.7 MMBTU/hr	0.10	--	--	--	--	--
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW	--	--	--	75 @ 15% O_2	H_2O Injection	--
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	--	--	--	--	--	--
U.S. Borax & Chemical Corp.	CA	Feb-87	Gas Turbine	45 MW	--	40	--	25 ppm @ 15% O_2	Proper Combust. Techniques	--
Sierra LTD.	CA	Feb-87	GE Gas Turbine	11.34 MMCF/D	0.016	4.04	--	--	Steam Injection & SCR	95.86%
Midway-Sunset Project	CA	Jan-87	Gas Turbines (3)	973 MMBTU/hr	--	113.4	--	16.31 ppmv	H_2O Injection	73.00%
City of Santa Clara	CA	Jan-87	Gas Turbine	--	--	--	--	42 @ 15% O_2	Water Injection	--
O'Brien KRG Systems/Merchants Refrig	CA	Dec-86	Gas Turbine	359.5 MMBtu/hr	--	30.3	--	15 @ 15% O_2	Water Injection & SCR	--
California Dept. of Corr.	CA	Dec-86	Gas Turbine	5.1 MW	--	--	--	38 @ 15% O_2	1:1 H_2O Injection	--
Double 'C' Limited	CA	Nov-86	Gas Turbine	25 MW	--	8.08	--	--	H_2O Inj. & Selected Catalytic Red.	--
Kern Front Limited	CA	Nov-86	Gas Turbine (2)	50 MW	--	8.08	--	4.5 @ 15% O_2	Water Injection & SCR	95.80%
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	--	63	--	25 ppm @ 15% O_2	Steam Injection @ St/F Ratio of 1.7/1	75.00%
Wichita Falls E. I., I.	TX	Jun-86	Gas Turbine	20 MW	--	--	684	--	Steam Injection	--
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	--	--	640	--	Steam Injection	--
Kern Energy Corp.	CA	Apr-86	Gas Turbine	8.8 MMCF/D	0.023	8.29	--	--	Steam Inj., Low NO_x Config. & SCR	87.00%
Monarch Cogen	CA	Apr-86	Combined Cycle	92.20 MMBtu/hr	--	8.02	--	22 @ 15% O_2	SCR	--
Moran Power, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.02	8.29	--	--	Steam Inj., Low NO_x Config. & SCR	87.00%
Southeast Energy, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.023	8.29	--	--	Steam Inj., Low NO_x Config. & SCR	87.00%
Western Power System, Inc	CA	Mar-86	GE Gas Turbine	26.5 MW	--	--	--	9 @ 15% O_2	H_2O Injection & SCR	80.00%
AES Placerita, Inc.	CA	Mar-86	Turbine	519 MMBTU/hr	--	26.2	--	7 @ 15% O_2	H_2O Injection & SCR	--
OLS Energy	CA	Jan-86	GE Gas Turbine	256 MMBTU/hr	--	--	--	9 @ 15% O_2	H_2O Injection & Scrubber	80.00%
Union Cogeneration	CA	Jan-86	Gas Turbine	16 MW	--	--	--	25 @ 15% O_2	H_2O Injection & Scrubber	--

injection is used initially to reduce NO_x emissions. However, advanced dry low-NO_x technology has only recently been developed and made available for gas turbines. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process.

SCR has been installed or permitted in about 132 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About 83 percent (i.e., 109) of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, 43 percent have been in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

As noted previously, there are distinct regulatory and policy differences between LAER and BACT.

All the projects in California have natural gas as the primary fuel, and only 15 of the SCR applications in California have distillate fuel as backup.

The remaining projects with SCR (i.e., 23 projects) are located in the eastern United States. These projects are located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with 87 percent less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per GT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent. The most stringent emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, two facilities have reported emission limits of about 4.5 ppm. These emission limits were clearly determined to be LAER on GTs using water injection with uncontrolled NO_x levels below 42 ppm. SCR has not been installed or permitted on simple cycle GTs.

Wet injection has been the primary method of reducing NO_x emissions from GTs. This method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when burning natural gas. More recently, GT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

In Florida, a majority of the most recent PSD permits and BACT determinations for gas turbines have required either wet injection or dry low-NO_x technology for NO_x control. The emission limits included in these permits and BACT determinations are 25 ppm (corrected to 15 percent O_2, dry conditions) for natural-gas firing.

B.2.1.2 <u>Technology Description and Feasibility</u>

<u>Wet Injection</u>--The injection of water or steam in the combustion zone of GTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor

design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the GT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

Dry Low-NO_x Combustor--In the past several years, GT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on conventional machines manufactured by GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. GE and Westinghouse have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the GT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level guaranteed by the proposed vendors for the project is 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

Selective Catalytic Reduction (SCR)--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle GTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions.

This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table B-4.

As presented in Table B-4, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°F to 950°F, have been available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,000°F and above, the zeolite catalyst will be irreparably damaged. Therefore, application of an SCR system using a zeolite catalyst on a simple cycle operation is technically infeasible without exhaust gas cooling. Moreover, since zeolite catalysts have not been operated continuously in combustion exhausts greater than 900°F, the cooling system would have to reduce turbine exhaust temperatures about 200°F (i.e., to around 800°F).

Table B-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems, such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates backpressure on the turbine, which reduces overall heat rate.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x before to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within (i.e., about 100°F) must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.

Table B-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 2 of 2)

Consideration	Description
Ammonia Control	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip (NH_3 that passes unreacted through the catalyst and into the atmosphere) can occur if 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can occur when firing natural gas. These compounds are emitted as particulates.
Ammonia Transportation and Storage	Storage and handling of anhydrous ammonia produces additional environmental risks. Appropriate controls and contingency plans in the event of a release is required.

NO_xOUT Process--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75-MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the GT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal $DeNO_x$--Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal $DeNO_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal $DeNO_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with GTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of construction-specified material, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal $DeNO_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of a combustion turbine is typically about 1,000°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

<u>Nonselective Catalytic Reduction</u>--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. GTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for GTs.

<u>Control Technologies for Duct Firing</u>--The proposed control technology for duct firing in the HRSG will be the use of combustion controls that will limit the emissions to 0.1 lb/10^6 Btu heat input.

The applicable NSPS for the secondary HRSG are the standards promulgated for industrial-commercial-institutional steam generating units contained in 40 CFR Part 60 Subpart Db. These NSPS, for steam generators with a heat input greater than $100x10^6$ Btu/hr, limit NO_x emissions from natural gas firing to 0.2 lb NO_x per 10^6 Btu heat input. BACT emission limits for duct burners located in HRSGs associated with combined cycle power plants are typically 0.1 lb NO_x per 10^6 Btu heat input.

<u>Technology Determination</u>--A technical evaluation of other tail gas controls (i.e., NO_xOUT, Thermal DeNO_x, and NSCR) indicates that these processes have not been applied to GT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the BACT analysis, the advanced dry low-NO_x combustor alone can achieve 25 ppm (corrected) and the SCR with dry low-NO_x combustor is capable of achieving a NO_x emission level of 9 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions). When firing oil, the emissions with SCR and wet injection would be about 15 ppm (corrected), whereas emissions with SCR and wet injection would be about 15 ppm (corrected), whereas emissions with wet injection alone would be 42 ppm (corrected). However, the SCR has an associated ammonia slip (i.e., 10 ppm).

B.2.1.3 SCR Cost Estimates

Tables B-5 and B-6 present the total capital and annualized cost for SCR, respectively.

B.2.2 CARBON MONOXIDE

B.2.2.1 Identification of CO Control Technologies

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table B-7 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in GTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. For the GTs being evaluated, CO emissions will not exceed 15 ppmvd, corrected to dry conditions when firing natural gas under full load conditions and 50 ppmvd when firing distillate oil.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

For duct firing, the specific burner design to control NO_x emissions has commonly established the ability of the burner to meet CO limits. Recent BACT decisions for duct firing have ranged from 0.14 $lb/10^6$ Btu for Tropicana Products, Inc. to 0.2 $lb/10^6$ Btu for the Lake and Pasco Cogen

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	725,000	Developed from manufacturer budget quotations[a]
Ammonia Storage Tank	250,000	Developed from manufacturer budget quotations[b]
HRSG Modification	440,000	Developed from manufacturer budget quotations[c]
Indirect Capital Costs		
Installation and Foundation (Includes Contractor Fee)	1,298,300	45% of SCR associated equipment and catalyst[d]
Engineering, Erection Supervision, Startup, and O&M Training	487,300	10% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG costs, installation labor.[e]
Project Support	268,000	5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs, and installation labor.[f]
Ammonia Emergency Prepardness Program	20,300	Engineering estimate
Liability Insurance	26,800	0.5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs and installation labor.
Interest During Construction	851,300	15% of all direct and indirect capital costs, including catalyst cost[g]
Contingency	929,800	25% of all capital costs[h]
Total Capital Costs	5,296,800	Sum of all capital costs

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Annualized Capital Costs</u>	622,200	Capital recovery of 10% over 20 years, 11.74% per year[i]
<u>Recurring Capital Costs</u>		
SCR Catalyst (Materials and Labor)	2,160,000	Developed from manufacturer budget quotations[j]
Contingency	540,000	25% of recurring capital costs[k]
<u>Total Recurring Capital Costs</u>	2,700,000	Sum of recurring capital costs
<u>Annualized Recurring Capital Costs</u>	1,085,700	Capital recovery of 10% over 3 years, 40.21% per year[l]

Note: HRSG = heat recovery steam generators.
SCR = selective catalytic reduction.

Footnotes for Table B-5

Note: All calculations rounded to nearest 100.

a. Developed from various vendor data as an algorithim to account for mass flow (lb/hr) through HRSG.

The SCR associated cost is made up of 2 factors:

1. Catalyst Housing, vaporizer, and HRSG wash system is \$100.7 per 1,000 lb/hr mass flow at normal operating conditions (i.e., ~3,600,000 lb/hr).

   $\$100.7 \times 3{,}600\ 10^3$ lb/hr = \$362,500

2. Control system costs = \$362,500

   Total is \$725,000

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Footnotes for Table B-5 (continued)

b. Ammonia tank size is based on SCR size as follows:

$69.45/1,000 lb mass flow x 3,600 x 10^3 lb/hr = $250,000

c. HRSG modifications based on mass flow at $122.2 per 1,000 lb mass flow.

$122.22/$10^3$ lb x 3,600 x 10^3 lb/hr = $440,000

d. From EPA OAQPS cost control manual

($725,000 + $2,160,000) x 0.45 = $1,298,300

e. From EPA OAQPS cost control manual

($725,000 + $250,000 + $2,160,000 + $440,000 + $1,298,300) x 0.10

= $487,300

f. Engineering estimate; same as engineering costs except use 0.005.

g. From OAQPS cost control manual and engineering estimate.

0.15 x ($725,000 + $250,000 + $440,000 + $1,298,300 + $487,300

+ $268,000 + $20,300 + $26,800 + $2,160,000) = $851,300

h. From EPA OAQPS cost control manual and engineering estimate

0.20 x ($725,000 + $250,000 + $440,000 + $1,298,300 + $487,300

+ $268,000 + $20,300 + $26,800 + $851,300) - (0.25 x 0.30

x $2,160,000)

= $929,800; note that the (0.25 x 0.30 x $2,160,000)

removes contingency for catalyst.

i. OAQPS cost control manual; standard statistical tables for 10% interest over 20 years

$5,296,800 x 0.1174 = $622,200

j. Developed from manufacturer data at $0.6/lb mass flow:

$0.6 x 3,600,000 = $2,160,000

Table B-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Footnotes for Table B-5 (continued)

k. Same rationale as h:

0.25 x $2,160,000 = $622,200

l. Manufacturer guarantees of 3 years life or catalyst. Used OAQPS cost control manual interest of 10 percent over 3 years (40.21 percent per year):

0.4021 x $2,700,000 = $1,085,700

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	31,200	16 hours/week @ $25/hour[a]
Ammonia	51,500	$300/ton; $NH_3:NO_x$ - 1:1 volume[b]
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ $75/hour plus expenses @ 35% labor[c]
Inventory Cost	84,600	Capital recovery (11.74%/year) for 1/3 of catalyst cost[d]
Catalyst Disposal Cost	100,000	Engineering estimate[e]
Contingency	83,100	25% of indirect costs[f]
Energy Costs		
Electrical	35,000	80 kWh/hr; $0.05/kWh[g]
Heat Rate Penalty	321,900	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh[h]
MW Loss Penalty	432,000	207 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted[i]
Fuel Escalation Costs	162,300	Real cost increase of fuel [j]
Contingency	129,800	25% of energy costs; excludes fuel escalation[k]
Total Direct Annual Costs	1,439,500	Sum of all direct annual costs

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Indirect Annual Costs		
Overhead	57,100	60% of ammonia and 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)[l]
Property Taxes and Insurance	159,900	2% of total capital costs[m]
Annualized Capital Costs	622,200	Capital recovery of 10% over 20 years, 11.74% per year (from Table B-5)
Recurring Capital Costs	1,085,700	Capital recovery of 10% over 3 years, 40.21% per year (from Table B-5)
Total Indirect Annual Costs	1,924,900	Sum of all indirect annual costs
Total Annual Costs	3,364,400	Total annualized cost[n]
Cost Effectiveness ($/ton NO_x)	7,370	Total annual costs divided by tons NO_x removed[o]

Note: All calculations rounded to the nearest $100.

kW = kilowatt.
kWh = kilowatt-hour.
kWh/hr = kilowatt-hour per hour.
MM/Btu = million British thermal units.
NH_3 = ammonia.
NO_x = nitrogen oxides.
O&M = operation and maintenance.

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Footnotes for Table B-6

Note: all calculations rounded to nearest 100

a. Engineering Estimate:

24 hours/week x 52 weeks/year x $25/hour = $31,200

b. Delivered cost of ammonia at $300/ton

464 TPY removed x $300 x 17/46 (molecular weight of ammonia to NO_x)

= 51,500

c. 80 hours/yr x $75 x 1.35 = $8,100

d. Required to purchase and store 1/3 of a catalyst for replacement or required.

$2,160,000 x 0.1174 (20 years @ 10 percent) + 3 = $84,600

e. Estimated as $27.77/1,000 lb mass flow; based on catalyst volume.

$27.77 x 3,600 (1,000 lb mass flow) = $100,000

f. OAQPS cost control manual background documents

0.25 x ($31,200 + $51,500 + $8,100 + $84,600 + $100,000) = $83,100

g. 80 kWh/hr from SCR manufacturer; $0.05/kWh is cost of estimated energy:

80 kWh/hr x $8,760 hr/yr x $0.08/kWh = $35,000

h. 4" back pressure from SCR manufacturer; 0.8 percent energy loses from general CT performance curver; 147 MW power rating at ISO (59°F) conditions.

147 MW x 0.005 x 8,760 hrs/yr x 1,000 kW/mw x $0.05/kWh = $321,900

i. 3 days required to change catalyst or maintenance; saving in gas usage subtracted

207 MW x 3 days x 24 hours x $0.05/kWh x 1,000 mwh - (1,450 x 10^6 Btu/hr

x 3 days x 24 hours x $3/$10^6$ Btu) = $432,000

Table B-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Footnotes for Table B-6 (continued)

j. Escalation of fuel costs over inflation; 3 percent over 20 years; factor calculated as 0.454565; applies to electrical and heat rate costs only:

0.454565 x ($35,000 + $321,900) = $162,300

k. OAQPS cost control manual background documents

0.25 x ($35,000 + $321,900 + $162,300) = $129,800

l. 0.6 ($51,500 + 1.15 x $31,200) + 0.15 x $31,200 = $57,100

m. From OAQPS cost control manual

0.02 x ($5,296,800 + $2,700,000) = $159,900

n. Total direct annual costs plus total indirect annual costs:

$1,439,500 + $1,924,900 = $3,364,400

o. Cost effectiveness is total annual costs divided by the tons removed (702.11 tons/yr x 0.65 = 456.4 tons/yr):

$3,364,400 ÷ 456.4 = $7,370/ton of NO_x removed

Table B-7. Summary of BACT Determinations for CO from Gas-fired Turbines (Page 1 of 2)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	42	78 ppmvd for oil firing	--
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	--	--	--	42	78 ppmvd for oil firing	--
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	--	--	--	--	25 ppmvd for oil firing	--
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	--	5.8	--	60 @ 15% O_2	Base Case, No Additional Control	--
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	--	--	--	6 @ 15% O_2	CO Catalyst	80.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	--	--	--	30	33 ppmvd for oil firing	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	--	--	261	30	Combustion control	--
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	--	--	261	30	Combustion control	--
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	--	--	--	30	33 ppmvd for oil firing	--
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	--	--	--	10	26 ppmvd for oil firing	--
March Point Cogen	WA	Oct-90	Turbine	80 MW	--	--	--	37 @ 15% O_2	Combustion Control	--
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	--	--	--	15 ppm	Good Combustion	--
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	--	25	--	--	Combustor Design & Operation	--
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	0.02	--	--	--	--	--
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	--	--	--	50 @ ISO Cond & 12% O_2	Design & Good Combustion Techniques	--
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	--	--	--	25 ppm	Combustion Control	--
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	0.112	--	--	--	--	--
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.022	10.8	--	--	Combustion Control	--
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	0.028	--	--	--	Combustion Control	--
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	--	--	--	10 @ 15% O_2	--	--
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	0.024	--	--	--	Combustion Control	--
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	0.026	--	--	--	Combustion Control	--
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	0.022	--	--	--	Combustion Control	--
Pawtucket Power	RI	Jan-89	Turbine	58 MW	--	--	--	23 @ 15% O_2	--	--
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	--	--	--	25 @ 15% O_2	--	--
Champion International	AL	Nov-88	Gas Turbine	35 MW	--	9	--	--	--	--
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	--	--	--	10 ppm	Combustion Control	--
Amtrak	PA	Oct-88	Turbine (2)	20 MW	--	30.76	--	--	--	--
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	0.021	--	--	--	Combustion Control	--
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	--	--	--	10 @ 15% O_2	Combustion Control	--
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	--	--	--	15 ppm	Good Combustion	--
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	0.022	--	--	--	Combustion Control	--
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	0.1	--		--	Combustion Control	--

Table B-7. Summary of BACT Determinations for CO from Gas-fired Turbines (Page 2 of 2)

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Efficiency (%)
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	0.605	--	--	--	--	--
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.181	--	--	--	CO Catalyst	80.00%
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	--	26	--	--	Turbine Design	--
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	--	94	--	--	Proper Combustion	--
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	0.048	--	--	--	--	--
Simpson Paper Co.	CA	Jun-87	Gas Turbine	49.50 MW	--	54.25	--	55 @ 15% O_2	Combustion Controls	--
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	--	55.25	--	55 @ 15% O_2	Combustion Control	--
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	--	--	--	50 @ 15% O_2	--	--
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	--	6	25	--	--	--
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW				109 lb/scf fuel	Combustion Control	--
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	--	--	--	10 @ 15% O_2	CO Catalyst & Comb. Control	--
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	--	--	--	--	CO Catalyst (No limit indicated)	--
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	--	--	32.4	--	--	--

Limited projects. The proposed CO BACT emission limit for the project is 0.1 lb/10^6 Btu.

B.2.2.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required.

For GTs, the oxidation catalyst can be located directly after the GT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired GTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

The lack of demonstrated operation with oil firing suggests rejection of catalytic oxidation as a technically feasible alternative. However, the advent of a second generation catalyst suggests that an oxidation catalyst could be used.

B.2.2.3 Oxidation Catalyst Costs

Table B-8 presents the capital and annualized cost for an oxidation catalyst.

Table B-8. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	138,750	Manufacture Estimate - $257 per lb/hr mass flow; 15% for equipment
2. Exhaust Modification	250,000	Engineering Estimate
3. Installation	293,750	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	88,125	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	117,500	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	58,750	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	23,500	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	242,590	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	299,880	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	1,512,850	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	177,700	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	786,250	Manufacture Estimate - $257 per lb/hr mass flow; 85% of catalyst
B. Contingency	196,560	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	982,810	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	395,200	Capital Recovery of 10% over 20 years
III. ANNUALIZED COST		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,980	4 hours/week, 52 weeks/year, $25/hour and 15% supervisor cost
2. Maintenance	12,480	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	30,280	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
B. ENERGY COSTS		
1. Heat Rate Penalty	128,800	0.2% heat rate penalty. $50/MW energy loss
2. MW Loss Penalty (catalyst changeout)	63,000	Loss of 147 MW for one day; cost of natural gas at $3/$10^6$ Btu deducted from cost
3. Fuel Escalation Costs	58,500	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	62,600	25% of energy costs
C. INDIRECT:		
1. Overhead	11,080	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	24,960	1% of Total and Recurring Capital Cost
3. Insurance	24,960	1% of Total and Recurring Capital Cost
4. Administration	49,910	2% of Total and Recurring Capital Cost
Annualized Capital Costs	177,700	
Annualized Recurring Capital Costs	395,200	
TOTAL ANNUALIZED COSTS	1,045,936	Sum of Operating and Maintenance and Annualized Capital Costs
Cost Effectiveness ($/ton NO_x removed)	14,756	Total annualized cost divided by CO removal (71 TPY; gas and oil to 10 ppmvd)

Note: All calculations using machine performance were based on 72°F conditions.
Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

APPENDIX C

SUMMARY OF GENERIC MODELING IMPACTS

ISCST2 OUTPUT FILE NUMBER 1 :DTGEN180.082
ISCST2 OUTPUT FILE NUMBER 2 :DTGEN180.083
ISCST2 OUTPUT FILE NUMBER 3 :DTGEN180.084
ISCST2 OUTPUT FILE NUMBER 4 :DTGEN180.085
ISCST2 OUTPUT FILE NUMBER 5 :DTGEN180.086
First title for last output file is: 1986 DESTEC / GENERIC / 10 G/S / NAT GAS VELOCITIES
Second title for last output file is: RUN 180 FOOT STACK / 70,100% LOADS; 27, 97 oF

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: G10027					
Annual					
	1982	0.0824	240.	4000.	--
	1983	0.0661	70.	2000.	--
	1984	0.0824	240.	4000.	--
	1985	0.0977	70.	2000.	--
	1986	0.1144	90.	2000.	--
HIGH 1-Hour					
	1982	9.8350	120.	300.	82011413
	1983	10.3219	300.	300.	83022713
	1984	11.7771	100.	300.	84032908
	1985	9.8844	130.	1000.	85060311
	1986	7.4769	90.	1000.	86080111
HSH 1-Hour					
	1982	9.6327	120.	300.	82011415
	1983	7.9956	70.	1000.	83081011
	1984	6.6240	10.	1000.	84090511
	1985	6.6217	250.	1000.	85090812
	1986	6.6470	50.	1000.	86090712
HIGH 3-Hour					
	1982	6.4892	120.	300.	82011415
	1983	4.4990	260.	1000.	83081912
	1984	4.5660	270.	1000.	84072512
	1985	4.4667	80.	2000.	85101315
	1986	4.6515	90.	1000.	86080112
HSH 3-Hour					
	1982	3.5158	250.	2000.	82090612
	1983	3.8249	40.	1500.	83090515
	1984	3.7363	260.	1000.	84072512
	1985	4.0633	80.	2000.	85042415
	1986	4.4275	90.	1000.	86071315
HIGH 8-Hour					
	1982	2.6729	240.	3000.	82050316
	1983	2.6045	50.	2000.	83083016
	1984	2.9070	250.	2000.	84061216
	1985	2.7723	90.	3000.	85060216
	1986	2.7357	90.	2000.	86100516
HSH 8-Hour					
	1982	2.2784	0.	2000.	82082716
	1983	2.2837	240.	3000.	83101616
	1984	2.1577	90.	2000.	84061916
	1985	2.3292	90.	2000.	85062816
	1986	2.7190	90.	2000.	86081816
HIGH 24-Hour					
	1982	1.1386	240.	2000.	82082924
	1983	1.1048	50.	2000.	83083024
	1984	1.0539	90.	2000.	84060224
	1985	1.0958	90.	3000.	85060224
	1986	1.2084	90.	2000.	86081824
HSH 24-Hour					
	1982	1.0150	0.	2000.	82082724
	1983	0.8381	240.	3000.	83101624
	1984	0.8568	90.	2000.	84083124

	1985	0.8568	80.	2000.	85060424
	1986	1.0071	90.	2000.	86072024
SOURCE GROUP ID: G10097					
Annual					
	1982	0.0969	240.	4000.	--
	1983	0.0758	70.	2000.	--
	1984	0.0935	240.	4000.	--
	1985	0.1130	70.	2000.	--
	1986	0.1330	90.	2000.	--
HIGH 1-Hour					
	1982	13.3253	130.	300.	82011414
	1983	12.8410	290.	300.	83022712
	1984	15.0724	220.	300.	84081704
	1985	10.8222	120.	300.	85021217
	1986	9.0647	10.	2000.	86121212
HSH 1-Hour					
	1982	11.8295	120.	300.	82011415
	1983	8.6258	290.	300.	83022709
	1984	12.5402	130.	300.	84022811
	1985	10.6668	120.	300.	85021214
	1986	7.1840	350.	1000.	86082212
HIGH 3-Hour					
	1982	8.1956	120.	300.	82011415
	1983	4.7802	260.	1000.	83081912
	1984	8.1705	120.	300.	84032912
	1985	6.8721	120.	300.	85021215
	1986	4.8852	90.	1000.	86080112
HSH 3-Hour					
	1982	3.9824	250.	2000.	82090612
	1983	4.0280	330.	2000.	83090412
	1984	6.0423	120.	300.	84032915
	1985	4.6637	80.	2000.	85042415
	1986	4.8608	90.	1000.	86071315
HIGH 8-Hour					
	1982	3.0734	120.	300.	82011416
	1983	3.0577	290.	300.	83022716
	1984	5.3298	120.	300.	84032916
	1985	3.1103	90.	2000.	85060216
	1986	3.1567	90.	2000.	86100516
HSH 8-Hour					
	1982	2.6291	0.	2000.	82082716
	1983	2.5936	240.	3000.	83061016
	1984	2.4770	90.	2000.	84061916
	1985	2.6613	90.	2000.	85062816
	1986	3.0679	90.	2000.	86081816
HIGH 24-Hour					
	1982	1.3406	240.	3000.	82050324
	1983	1.2329	50.	2000.	83083024
	1984	1.8636	130.	300.	84022824
	1985	1.5056	120.	300.	85021224
	1986	1.3635	90.	2000.	86081824
HSH 24-Hour					
	1982	1.1973	240.	2000.	82050324
	1983	0.9731	240.	3000.	83101624
	1984	0.9955	90.	2000.	84083124
	1985	0.9538	90.	3000.	85042824
	1986	1.1184	90.	2000.	86072024
SOURCE GROUP ID: G7027					
Annual					
	1982	0.1116	240.	4000.	--
	1983	0.0883	70.	2000.	--
	1984	0.1092	240.	3000.	--
	1985	0.1323	70.	2000.	--
	1986	0.1571	90.	2000.	--
HIGH 1-Hour					
	1982	16.1083	130.	300.	82011414

	1983	15.7330	290.	300.	83022712
	1984	17.9262	220.	300.	84081704
	1985	13.4108	120.	300.	85021217
	1986	10.9461	120.	300.	86012714
HSH 1-Hour					
	1982	14.1934	120.	300.	82011415
	1983	11.8351	110.	300.	83032416
	1984	15.3055	130.	300.	84022811
	1985	13.3936	120.	300.	85021214
	1986	8.0409	230.	700.	86082313
HIGH 3-Hour					
	1982	9.8242	120.	300.	82011415
	1983	7.3016	110.	300.	83032418
	1984	14.0222	120.	300.	84032912
	1985	9.4742	120.	300.	85021215
	1986	5.6045	10.	1500.	86063012
HSH 3-Hour					
	1982	6.5808	120.	300.	82011418
	1983	6.9996	110.	300.	83020315
	1984	7.7288	120.	300.	84032915
	1985	5.4027	80.	2000.	85042415
	1986	5.1673	90.	1000.	86080112
HIGH 8-Hour					
	1982	4.7554	120.	300.	82011416
	1983	4.5340	110.	300.	83020316
	1984	10.1898	120.	300.	84032916
	1985	4.4556	120.	300.	85021216
	1986	3.6719	90.	2000.	86100516
HSH 8-Hour					
	1982	3.3172	0.	2000.	82060616
	1983	2.8566	240.	3000.	83061016
	1984	3.0867	130.	300.	84032916
	1985	3.0749	90.	2000.	85062816
	1986	3.4962	90.	2000.	86081816
HIGH 24-Hour					
	1982	2.0506	120.	300.	82011424
	1983	1.5113	110.	300.	83020324
	1984	3.5757	120.	300.	84032924
	1985	2.3133	120.	300.	85021224
	1986	1.5674	90.	1500.	86081824
HSH 24-Hour					
	1982	1.4350	240.	2000.	82050324
	1983	1.1894	110.	300.	83032424
	1984	1.8546	120.	300.	84022824
	1985	1.1567	80.	1500.	85101124
	1986	1.2771	90.	2000.	86072024
SOURCE GROUP ID:	G7097				
Annual					
	1982	0.1217	240.	3000.	--
	1983	0.0972	90.	2000.	--
	1984	0.1192	240.	3000.	--
	1985	0.1440	70.	2000.	--
	1986	0.1734	90.	2000.	--
HIGH 1-Hour					
	1982	18.1638	130.	300.	82011414
	1983	17.8869	290.	300.	83022712
	1984	19.9664	220.	300.	84081704
	1985	15.4725	120.	300.	85021214
	1986	12.6341	120.	300.	86012714
HSH 1-Hour					
	1982	15.9307	120.	300.	82011415
	1983	13.9038	110.	300.	83031015
	1984	17.3627	130.	300.	84022811
	1985	15.3647	120.	300.	85021217
	1986	9.0998	230.	700.	86082313
HIGH 3-Hour					

	1982	11.0181	120.	300.	82011415
	1983	8.4475	110.	300.	83032418
	1984	16.1132	120.	300.	84032912
	1985	10.9431	120.	300.	85021215
	1986	6.1693	10.	1500.	86063012
HSH 3-Hour					
	1982	7.6627	120.	300.	82011418
	1983	8.2503	110.	300.	83020315
	1984	12.7449	130.	300.	84022806
	1985	8.3035	120.	300.	85021218
	1986	5.3299	90.	1000.	86080112
HIGH 8-Hour					
	1982	5.3772	120.	300.	82011416
	1983	5.3570	110.	300.	83020316
	1984	11.7426	120.	300.	84032916
	1985	5.8617	110.	300.	85021208
	1986	3.9786	90.	2000.	86100516
HSH 8-Hour					
	1982	3.5715	0.	2000.	82060616
	1983	3.0326	240.	2000.	83101616
	1984	6.1273	130.	300.	84022808
	1985	3.3268	90.	2000.	85062816
	1986	3.8359	90.	1500.	86100516
HIGH 24-Hour					
	1982	2.3351	120.	300.	82011424
	1983	1.7857	110.	300.	83020324
	1984	5.0949	130.	300.	84022824
	1985	3.5979	120.	300.	85021224
	1986	1.7314	90.	1500.	86081824
HSH 24-Hour					
	1982	1.5969	240.	2000.	82050324
	1983	1.3793	110.	300.	83032424
	1984	2.4163	120.	300.	84022824
	1985	1.2621	80.	1500.	85060424
	1986	1.3808	90.	2000.	86072024

ISCST2 OUTPUT FILE NUMBER 1 :DTCLASS1.082
ISCST2 OUTPUT FILE NUMBER 2 :DTCLASS1.083
ISCST2 OUTPUT FILE NUMBER 3 :DTCLASS1.084
ISCST2 OUTPUT FILE NUMBER 4 :DTCLASS1.085
ISCST2 OUTPUT FILE NUMBER 5 :DTCLASS1.086
First title for last output file is: 1986 DESTEC / CLASS 1 / 10 G/S / NAT GAS VELOCITIES
Second title for last output file is: RUN 180 FOOT STACK / 70,100% LOADS; 27, 97 oF

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: G10027					
Annual					
	1982	0.00590	340300.	3165700.	--
	1983	0.00440	340300.	3165700.	--
	1984	0.00260	340300.	3165700.	--
	1985	0.00380	343700.	3178300.	--
	1986	0.00400	343700.	3178300.	--
HIGH 24-Hour					
	1982	0.06808	340300.	3165700.	82072924
	1983	0.07004	340300.	3165700.	83090424
	1984	0.06539	342000.	3174000.	84041924
	1985	0.06348	341100.	3183400.	85110724
	1986	0.08764	340700.	3171900.	86121024
HSH 24-Hour					
	1982	0.06578	340300.	3165700.	82062524
	1983	0.06355	340300.	3165700.	83051524
	1984	0.04801	334000.	3183400.	84052424
	1985	0.04837	343700.	3178300.	85032924
	1986	0.07127	340300.	3169800.	86031124
SOURCE GROUP ID: G10097					
Annual					
	1982	0.00600	340300.	3165700.	--
	1983	0.00450	340300.	3165700.	--
	1984	0.00260	340300.	3165700.	--
	1985	0.00400	343700.	3178300.	--
	1986	0.00420	343700.	3178300.	--
HIGH 24-Hour					
	1982	0.07222	340300.	3165700.	82072924
	1983	0.07289	340300.	3165700.	83090424
	1984	0.06954	342000.	3174000.	84041924
	1985	0.07250	343700.	3178300.	85011924
	1986	0.08982	340700.	3171900.	86121024
HSH 24-Hour					
	1982	0.06999	340300.	3165700.	82062524
	1983	0.06648	340300.	3167700.	83120224
	1984	0.05030	334000.	3183400.	84052424
	1985	0.06653	341100.	3183400.	85011924
	1986	0.07392	340300.	3169800.	86031124
SOURCE GROUP ID: G7027					
Annual					
	1982	0.00630	340300.	3165700.	--
	1983	0.00470	340300.	3165700.	--
	1984	0.00290	340300.	3165700.	--
	1985	0.00420	343700.	3178300.	--
	1986	0.00430	340300.	3165700.	--
HIGH 24-Hour					
	1982	0.07699	340300.	3165700.	82072924
	1983	0.07614	340300.	3165700.	83090424
	1984	0.07388	342000.	3174000.	84041924
	1985	0.07551	343700.	3178300.	85011924
	1986	0.09225	340700.	3171900.	86121024
HSH 24-Hour					
	1982	0.07486	340300.	3165700.	82062524

	1983	0.07023	340300. 3167700.	83120224
	1984	0.05291	334000. 3183400.	84052424
	1985	0.06909	341100. 3183400.	85011924
	1986	0.07686	340300. 3169800.	86031124
SOURCE GROUP ID:	G7097			
Annual				
	1982	0.00640	340300. 3165700.	--
	1983	0.00480	340300. 3165700.	--
	1984	0.00300	340300. 3165700.	--
	1985	0.00430	343700. 3178300.	--
	1986	0.00450	340300. 3165700.	--
HIGH 24-Hour				
	1982	0.07987	340300. 3165700.	82072924
	1983	0.07879	340300. 3165700.	83090424
	1984	0.07656	342000. 3174000.	84041924
	1985	0.07748	343700. 3178300.	85011924
	1986	0.09369	340700. 3171900.	86121024
HSH 24-Hour				
	1982	0.07781	340300. 3165700.	82062524
	1983	0.07274	340300. 3167700.	83120224
	1984	0.05448	334000. 3183400.	84052424
	1985	0.07076	341100. 3183400.	85011924
	1986	0.07864	340300. 3169800.	86031124