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MUNICIPAL WASTE COMBUSTORS --
BACKGROUND INFORMATION FOR
PROPOSED STANDARDS: CONTROL OF NO_x EMISSIONS

FINAL REPORT

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TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

LIST OF TABLES

LIST OF TABLES **(CONTINUED)**

LIST OF TABLES **(CONTINUED)**

Table		Page

LIST OF FIGURES

1.0 INTRODUCTION

Emissions of nitrogen oxides (NO_x) from municipal waste combustors (MWC's) are generally not controlled before being released to the atmosphere. Methods of control, both through combustion modifications and add-on controls, are available but have been infrequently applied to MWC's. This report characterizes NO_x emissions from MWC's and assesses the performance and costs associated with controlling NO_x emissions.

In Section 2.0 of this report, available data on NO_x emissions from MWC's without add-on controls are summarized. Some of the NO_x emissions data may reflect combustion modifications normally used during MWC operation. The various control technologies for reducing NO_x emissions are reviewed in Section 3.0. The available performance data and operational experience for the different NO_x controls for MWC's are also presented.

In Section 4.0, cost algorithms are developed for Thermal $DeNO_x$, one of the add-on control technologies that has been applied to several new MWC's. A cursory cost analysis for selective catalytic reduction (SCR) is also presented. In Section 5.0, the cost algorithms for Thermal $DeNO_x$ are used to estimate annualized NO_x control costs and cost-effectiveness values for 12 model plants representative of new MWC's. The sensitivity of Thermal $DeNO_x$ annualized costs and cost effectiveness to variations in ammonia and electricity costs is also investigated.

2.0 NO_x EMISSIONS

Nitrogen oxides are formed during combustion through: (1) oxidation of fuel-bound nitrogen and (2) fixation of atmospheric nitrogen. Conversion of fuel-bound nitrogen occurs at relatively low temperatures (<2,000°F), while fixation of atmospheric nitrogen generally occurs at higher temperatures.[1] Most (75 to 80 percent) of the NO_x formed during normal operation of MWC's is associated with fuel-bound nitrogen.[2]

2.1 NO_x EMISSIONS FROM MWC'S WITHOUT ADD-ON NO_x CONTROLS

The available data on NO_x emissions from MWC's without add-on NO_x controls are listed in Table 2-1 by combustor type (NO_x emissions following add-on controls are presented in Section 3.0). The data are from test reports and responses to an EPA survey of MWC facilities. The data cover 52 MWC units (8 mass burn/refractory, 26 mass burn/waterwall, 5 refuse-derived fuel [RDF], 8 excess-air modular, and 5 starved-air modular) located at 35 different plants. Each data point represents the average of the NO_x test runs at the stated unit. Most of these tests were conducted during MWC compliance testing while the combustor was at full load and at normal operating conditions. Each test usually lasted from 1 to 3 hours and both manual (EPA Method 7A) and continuous emission monitoring (CEM) (EPA Method 7E) methods were used to measure NO_x emissions. Table 2-2 summarizes these data. Although none of these units were using add-on NO_x controls at the time they were tested, several of them used combustion controls to reduce NO_x formation in the combustor.

With one exception, NO_x emissions from these facilities ranged from 59 to 375 ppm at 7 percent O_2. The remaining unit had emissions of 611 ppm. The average NO_x concentration for all 52 data sets is 211 ppm. On a pound per million Btu (lb/MMBtu) basis, this concentration is slightly less than 0.4 lb/MMBtu. For mass burn/refractory units, the average NO_x concentration is 155 ppm and ranges from 59 to 239 ppm. The NO_x concentration from mass burn/waterwall units averages 242 ppm and ranges from 68 to 372 ppm. The 68 ppm value was obtained at Long Beach, which uses flue gas recirculation to reduce NO_x emissions, and was not included in the average. The remaining data were above 154 ppm. For RDF combustors, the average NO_x concentration

TABLE 2-1. AVERAGE NO_x EMISSIONS FROM MWC's

Site[a]	Unit Size (tons/day)	Test Date	O_2 (%)	NO_x (ppm)	NO_x (ppm at 7% O_2)	Ref.
Mass Burn/Refractory						
McKay Bay 2	250	09/85	11.8	39.0	59.4	3
Dayton 2	300	NR[b]	14.3	33.9	71.4	4
McKay Bay 3	250	09/85	11.6	100.4	152.1	3
Galax	56	NR	13.9	81.1	160.9	5
Philadelphia NW 1	375	02/87	13.9	86.0	171.1	6
Philadelphia NW 2	375	02/87	14.8	84.3	192.0	6
McKay Bay 4	250	09/85	13.3	106.5	216.4	3
Dayton 1	300	NR	14.8	104.8	238.8	4
Mass Burn/Rotary Waterwall						
Gallatin	100	02/83	9.1	124.2	146.1	7
Kure	165	11/80	12.0	105.6	164.9	8
Mass Burn/Waterwall						
Long Beach ($DeNO_x$ off)[c]	460	11/88	10.2	52.4	68.2	9
Commerce ($DeNO_x$ off)	300	06/87	10.0	121.0	154.3	10
Baltimore 3	750	01/85	11.1	136.3	193.7	11
Baltimore 2	750	01/85	12.1	122.3	193.9	11
Alexandria	325	12/87	9.4	171.3	207.8	12
Claremont 2	100	05/87	11.4	144.9	210.2	13
Peekskill	750	04/85	NR	NR	218.3	14
Hampton 1	100	06/88	11.0	156.3	219.2	15
Nashville Thermal	360	NR	10.6	164.0	221.4	16
Baltimore 1	750	01/85	12.0	141.8	222.0	11
Millbury 2	750	02/88	10.5	169.3	225.7	17
Millbury 1	750	02/88	10.3	177.5	233.7	17

(continued)

TABLE 2-1 (CONTINUED). AVERAGE NO_x EMISSIONS FROM MWC's

Site[a]	Unit Size (tons/day)	Test Date	O_2 (%)	NO_x (ppm)	NO_x (ppm at 7% O_2)	Ref.
Mass Burn/Waterwall (cont.)						
Peekskill	750	11/85	11.7	156.7	236.3	18
Hampton 2	100	06/88	9.5	194.7	238.6	15
Marion County 2	275	06/87	9.6	196.9	244.3	19
Claremont 1	100	05/87	12.2	161.0	258.8	13
Wurzburg	330	12/85	NR	NR	260.7	20
Marion County 2	275	09/86	10.6	211.8	284.9	21
Pinellas County	1,000	02/87	9.2	240.0	285.7	22
Stanislaus 1 ($DeNO_x$ off)	400	12/88	NR	NR	297.0[d]	23
Stanislaus 2 ($DeNO_x$ off)	400	12/88	NR	NR	304.0[d]	23
Quebec City	250	03/85	11.6	205.4	314.0	24
Tulsa 1	375	06/86	9.2	308.5	367.7	25
Tulsa 2	375	06/86	8.6	328.2	372.2	25
RDF						
Mid-Connecticut 11	675	07/88	9.9	153.4	194.6	26
Biddeford	350	12/87	8.3	206.5	228.0	27
Niagara Falls	1,000	05/85	NR	NR	267.9	28
Albany	300	06/84	NR	NR	293.0	29
Lawrence	1,000	09/87	12.0	221.2	345.3	30
Modular, Excess-Air						
Pigeon Point 2[c]	120	01/88	11.7	69.8	104.8	31
North Aroostook	50	NR	9.9	89.7	111.9	32
Pigeon Point 3[c]	120	01/88	11.3	78.5	114.0	31
Pigeon Point 4[c]	120	01/88	11.2	81.3	116.9	31
Pigeon Point 1[c]	120	01/88	11.2	87.7	125.5	31

(continued)

TABLE 2-1 (CONCLUDED). AVERAGE NO_x EMISSIONS FROM MWC's

Site[a]	Unit Size (tons/day)	Test Date	O_2 (%)	NO_x (ppm)	NO_x (ppm at 7% O_2)	Ref.
Modular, Excess-Air (cont.)						
Pittsfield[c]	120	10/85	8.9	110.1	129.1	33
Pittsfield[c]	120	06/86	8.9	120.1	138.7	34
Pope/Douglas	100	07/87	13.4	152.7	281.5	35
Modular, Starved-Air						
Oneida	50	08/85	NR	NR	86.4	36
Tuscaloosa	75	05/85	11.3	162.3	235.1	37
Red Wing	90	09/86	12.3	160.7	259.9	38
Prince Edward Island	36	11/84	11.9	179.4	279.4	39
Cattaraugus	38	09/84	NR	NR	610.7	40

[a]Number following site name indicates combustor train number. It is provided if different combustor trains were evaluated as part of the same test.

[b]NR = Not reported.

[c]Emissions reflect use of flue gas recirculation to reduce NO_x emissions.

[d]NO_x concentration in ppm at 12 percent CO_2.

TABLE 2-2. SUMMARY OF NO_x EMISSIONS DATA FROM MWC's

Combustor Type	Number of Units	NO_x Emissions[a] (ppm at 7 percent O_2) Average	Range
Mass Burn/Refractory	8	155	59 - 240
Mass Burn/Waterwall	26[b,c]	240	154 - 370
RDF	5	270	195 - 345
Modular, Excess-Air	8	140	105 - 280
Modular, Starved-Air	5	215[d]	86 - 280
All Types	52	210[e]	59 - 370

[a]Averages rounded to nearest 5 ppm.

[b]Includes data from two mass burn/rotary waterwall combustors with NO_x emissions of 146 and 165 ppm. Without these points, the average NO_x concentration still rounds to 240 ppm.

[c]Excludes data from one unit with flue gas recirculation with NO_x emissions of 68 ppm. With this point, the average NO_x concentration still rounds to 240 ppm.

[d]Excludes one atypical data point of 611 ppm. With this point included, the average NO_x concentration is 295 ppm.

[e]Excludes one atypical data point of 611 ppm for a modular starved-air facility. With this point included, the average is 220 ppm.

is 266 ppm with a range of 195 to 345 ppm. For excess-air modular units, the NO_x emissions average 138 ppm and range from 105 to 282 ppm. The data for excess-air modular units are heavily weighted by the data from Pigeon Point and Pittsfield, which have Vicon units that employ flue gas recirculation (FGR) (approximately 35 percent of the total air supply). This technology accounts for 70 percent of the total design throughput capacity of modular excess-air units. The North Aroostook and Pope/Douglas combustors do not employ FGR. For modular starved-air facilities (including the 611 ppm emission rate from Cattaraugus), the average NO_x concentration is 294 ppm. Excluding Cattaraugus, the average is 215 ppm with a high concentration of 279 ppm.

An analysis of variance of the NO_x emissions data was performed to determine if there are any significant differences between the emissions from the different MWC combustor types. This analysis, the Duncan Range Test, compares the means and ranges of the data from each combustor type and determines, to a 95-percent confidence level, whether the data from different combustor types are distinct. The analysis shows that NO_x emissions from mass burn/waterwall, starved-air modular, and RDF combustors are similar, and that NO_x emissions from mass burn/refractory and excess-air modular combustors are similar. However, NO_x emissions from mass burn/waterwall and mass burn/refractory combustors are also statistically similar, leaving no distinct differences between the two similar groups of combustors. Thus, although the average NO_x emissions for the different combustors show some variation, the variations are not large enough to support a conclusion that different MWC combustor types have different NO_x emission values.

The observed variations in NO_x emissions could be due to normal daily variations as well as seasonal factors. For example, continuous NO_x measurements were collected between July and September 1988 as part of a test program at the MWC facility in Millbury, Massachusetts. Although combustor operation during the testing was maintained as close to normal as possible, these data range from less than 50 ppm to nearly 500 ppm at 7 percent O_2.[41] Similarly, at the MWC in Marion County, Oregon, variations in NO_x emissions of 120 ppm during a single day under normal operating conditions were observed.[42]

2.2 FACTORS AFFECTING NO_x EMISSIONS

In Figure 2-1, NO_x emissions are shown by month for each combustor type to show seasonal variations. For mass burn/waterwall combustors, NO_x emissions are generally higher in the summer months than in the winter months. (The 140 ppm value recorded in June was from Commerce, which burns primarily commercial refuse). However, NO_x emissions between 210 and 290 ppm were observed for all the months with data. Insufficient data are available for the other combustor types to determine similar trends. The observed higher NO_x emissions from mass burn/waterwall units during the summer months may be due to higher nitrogen content of the fuel because the raw refuse contains more yard wastes, which have a high nitrogen content.

Previous investigations of NO_x emissions from coal-, oil-, and gas-fired utility boilers have found that combustor load can affect NO_x emissions.[43] At MWC facilities in Marion County,[44] Peekskill,[45] and Quebec City,[46] NO_x emissions were measured during short-term tests at different combustor loads. In addition, at Marion County and Quebec City, NO_x emissions were measured at different excess air rates and overfire air distributions. These data are summarized in Table 2-3.

During the Marion County tests, the NO_x emissions at low load and normal air supply (76 percent of full load, Run 6a) averaged 257 ppm at 7 percent O_2 while the five tests at normal load and normal air supply (Runs 1, 2, 10, 11a, 11b) averaged 286 ppm at 7 percent O_2, a difference of about 10 percent. However, the low load NO_x measurement is within the range of the normal load measurements (255 to 309 ppm). Comparison of low load versus normal load at Peekskill (Runs 11-13 versus Runs 2-7) and Quebec City (Runs 2, 10, and 11 versus Runs 5, 6, and 12) are inconclusive, due to simultaneous changes in load and excess air. Comparisons of the effects of high load versus normal load at Peekskill (Runs 8-10 versus Runs 2-7) and Quebec City (Runs 7 and 9 versus Runs 5, 6, and 12) on NO_x emissions failed to find any clear impact of load on NO_x emissions. Based on these data, changes in load within the range tested (70-115 percent of design) do not appear to have any significant impact on NO_x emissions.

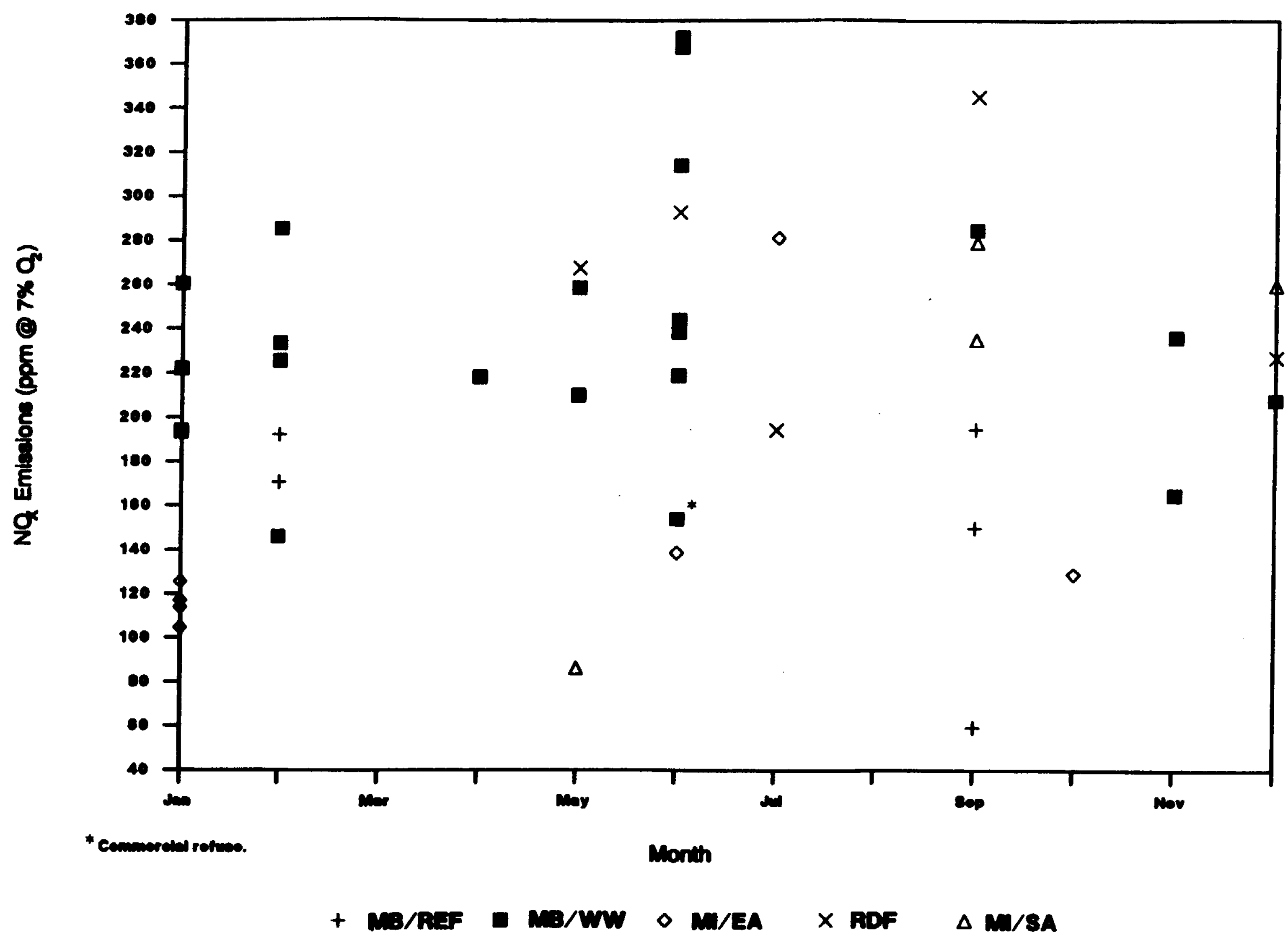

Figure 2-1. Seasonal variations in NO_x emissions

TABLE 2-3. NO_x VARIATIONS WITH COMBUSTOR LOAD

Site	Run	Load (% (of full)	NO_x (ppm)	NO_x (ppm, 7% O_2)	O_2 (%)	Comments[a]
Marion County	1	100	264	308	9.0	
Marion County	2	100	262	309	9.1	
Marion County	10	100	228	269	9.1	
Marion County	11a	100	218	255	9.0	
Marion County	11b	100	240	288	9.3	
Marion County	3a	95	218	203	6.0	LEA
Marion County	3b	95	230	317	10.8	HEA
Marion County	4	98	190	220	8.9	LOA
Marion County	5	103	240	276	8.8	HOA
Marion County	6a	76	220	257	9.0	
Marion County	6b	71	142	232	12.4	HEA
Marion County	7	77	184	195	7.8	LEA
Marion County	8	74	150	188	9.8	LOA
Marion County	9	78	219	282	10.1	HOA
Peekskill	2	100	191	239	9.8	
Peekskill	3	100	193	279	11.3	
Peekskill	5	100	179	242	10.6	
Peekskill	6	100	181	249	10.8	
Peekskill	7	100	174	242	10.9	
Peekskill	8	113	160	232	11.3	
Peekskill	9	112	164	230	11.0	
Peekskill	10	113	190	256	10.6	
Peekskill	11	87	147	240	12.4	
Peekskill	12	87	155	251	12.3	
Peekskill	13	87	133	220	12.5	
Quebec City	2	71	155	272	13	
Quebec City	10	71	127	224	13	
Quebec City	11	71	128	200	12	
Quebec City	5	100	158	184	9	
Quebec City	6	100	155	181	9	
Quebec City	12	100	149	190	10	
Quebec City	7	114	155	198	10	
Quebec City	9	114	185	236	10	
Quebec City	3	100	168	262	12	HEA
Quebec City	4	99	164	256	12	HEA
Quebec City	14	101	127	199	12	LOA
Quebec City	15	101	137	193	11	LOA

[a]Tests where air supply was purposely varied are noted.
HEA = high excess air; LEA = low excess air; HOA = high overfire air; LOA = low overfire air. Other tests may have shown similar variation (i.e., similar O_2 levels), but these tests were not designed around air supply changes.

Tests to evaluate the impact of high excess air (HEA) during normal load operation at Marion County (Run 3b) and Quebec City (Runs 3 and 4) suggest that HEA increases NO_x emissions. However, during low load tests at Marion County, NO_x emissions were lower with HEA (Run 6b) than with normal air supply (Run 6a). Emissions of NO_x during tests at Marion County with low excess air (LEA) at normal load (Run 3a) and low load (Run 7) were both lower than tests at normal air supply and corresponding loads. Tests at Marion County (Runs 4, 5, 8, and 9) and Quebec City (Runs 14 and 15) during which the distribution of air above and under the grate was varied suggests that low overfire air (LOA) reduces NO_x emissions. The impact of high overfire air (HOA) on NO_x emissions, however, appears small. Further discussion of the use of LEA and overfire air distribution as NO_x control techniques is presented in Section 3.1.

A multivariate analysis of the effects of load, excess air, and overfire air distribution on NO_x emissions was performed with the data from Marion County and Quebec City. The results are summarized in Table 2-4. No single variable yields a significant correlation. Stronger correlations result as each additional variable is included in the analysis, suggesting that NO_x emissions are dependent on all three variables. However, the final correlation coefficients are not high, suggesting that other parameters such as fuel composition or heating value also affect NO_x emissions.

2.3 RELATIONSHIP BETWEEN NO_x AND OTHER FLUE GAS EMISSIONS

It is generally thought that NO_x emissions increase as combustion efficiency increases. This implies that an inverse relationship between NO_x and CO emissions should exist. The available NO_x and CO emission data from two facilities were used to investigate this relationship. The relationships between NO_x and O_2 emissions and between NO_x and CDD/CDF emissions were also investigated.

Figure 2-2 presents NO_x and CO emissions data measured at the Olmsted County, MN, mass burn combustor during parametric tests examining the impact of air supply. The single point in the lower right corner of the figure with low NO_x and high CO emissions was obtained under very poor combustion

TABLE 2-4. MULTIVARIATE ANALYSIS OF NO_x EMISSIONS AS A FUNCTION OF LOAD, EXCESS AIR, AND OVERFIRE AIR DISTRIBUTION

Test	Correlation Coefficient (R^2)	
	Marion County	Quebec City
NO_x vs. load	0.2631	0.0666
NO_x vs. excess air	0.0328	0.4259
NO_x vs. overfire air distribution	0.2295	0.0846
NO_x vs. load, excess air	0.4579	0.5209
NO_x vs. load, excess air, overfire air distribution	0.6157	0.7296

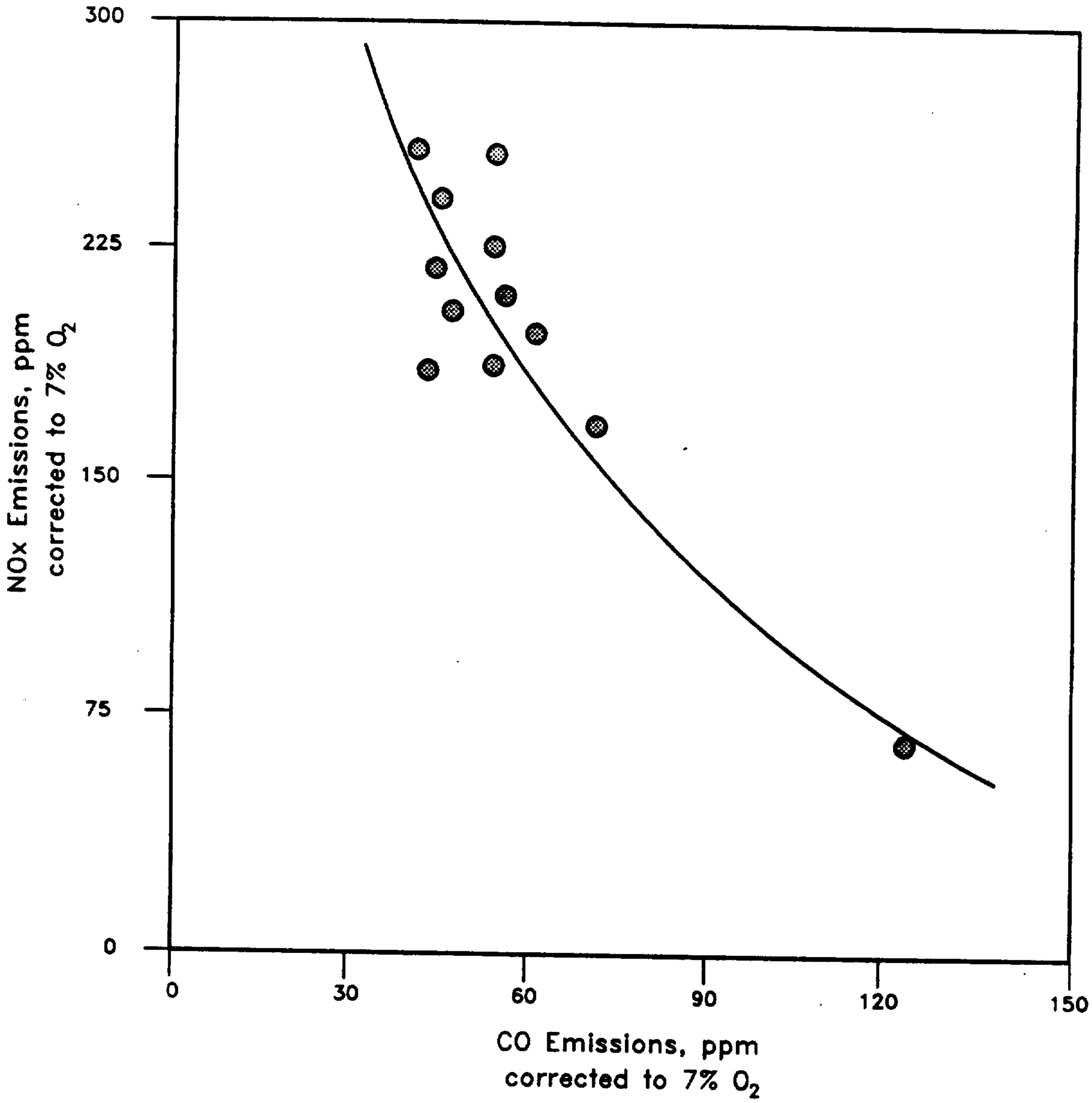

Figure 2-2. NO_x versus CO for a Mass Burn Combustor.[47]

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conditions (zero excess air). Taken as a whole, these data support the existence of an inverse relationship between NO_x and CO, with NO_x emissions increasing with decreasing CO emissions. At CO levels below 60 ppm, however, there is no apparent trend in the NO_x measurements.

Figure 2-3 presents 1,330 1-hour average CEM measurements of NO_x and CO collected at the Millbury MWC between July 15 and September 15, 1988. The average NO_x value is 223 ppm at 7 percent O_2. Eighty-five percent of the measurements are between 175 ppm and 275 ppm. Ninety-nine percent of the measurements are less than 360 ppm. Within the measured range of CO emissions (25-60 ppm), no trend in NO_x emissions occurs. These results are consistent with the data from Olmsted County in Figure 2-2. The NO_x and O_2 data from Millbury are plotted in Figure 2-4. Most of the O_2 values are between 8 and 13 percent. As with the NO_x and CO measurements, there is no apparent relationship between NO_x and O_2.

Two of the facilities with above average NO_x concentrations (Pinellas County and Marion County, both of which have Martin combustors) have reported very low CDD/CDF concentrations. This suggests that the combustion conditions associated with CDD/CDF destruction may contribute to NO_x formation. A plot of NO_x emissions versus CDD/CDF emissions for eight different MWC plants is shown in Figure 2-5. Examining all of the data as a set as well as the data from each individual plant, NO_x emissions do not vary significantly as the CDD/CDF concentration changes. For CDD/CDF concentrations of 30 to 1,200 ng/dscm, NO_x emissions are consistently between 200 and 330 ppm.

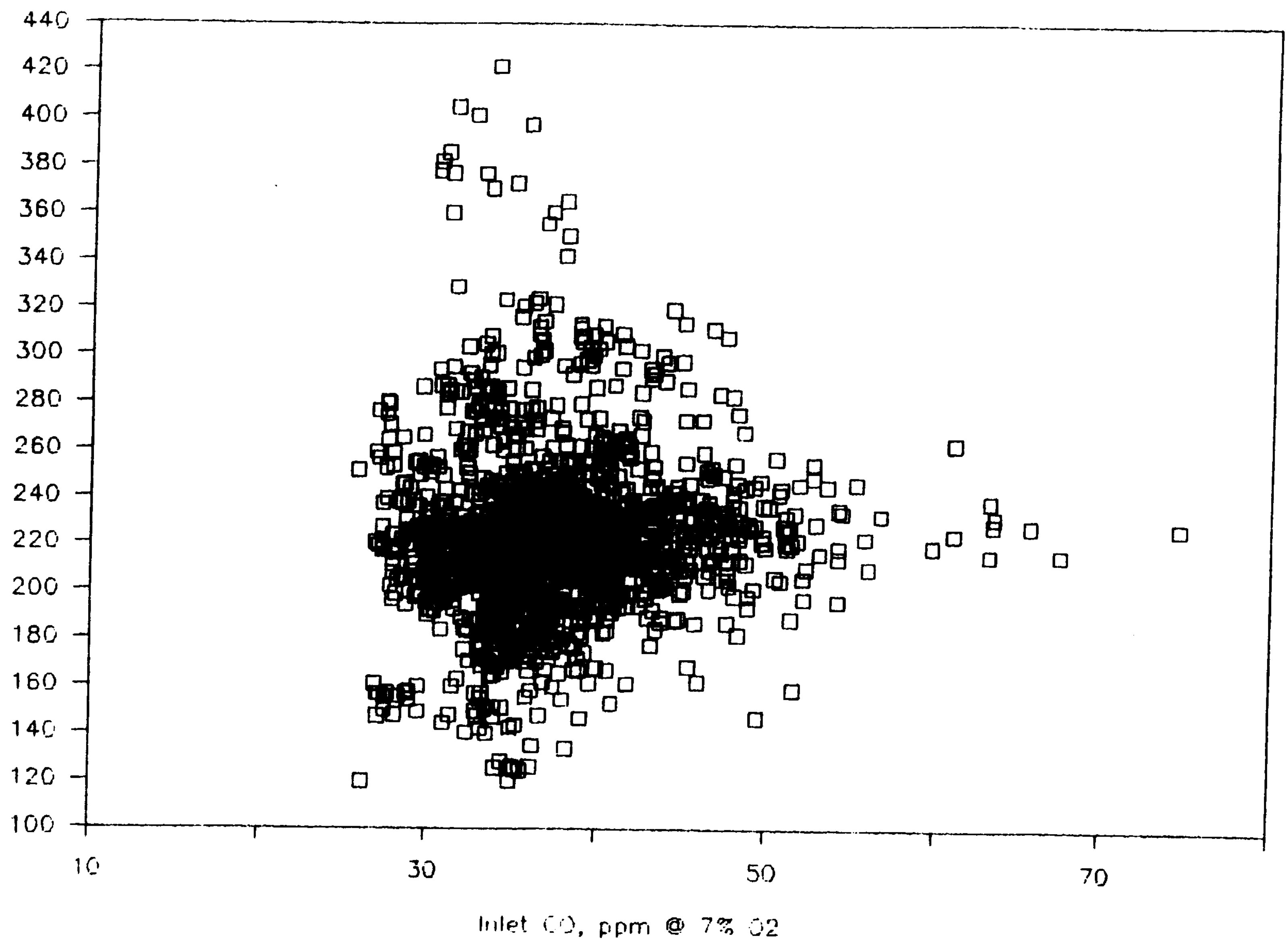

Figure 2-3. Long-term NO_X versus CO emissions for the Millbury MWC

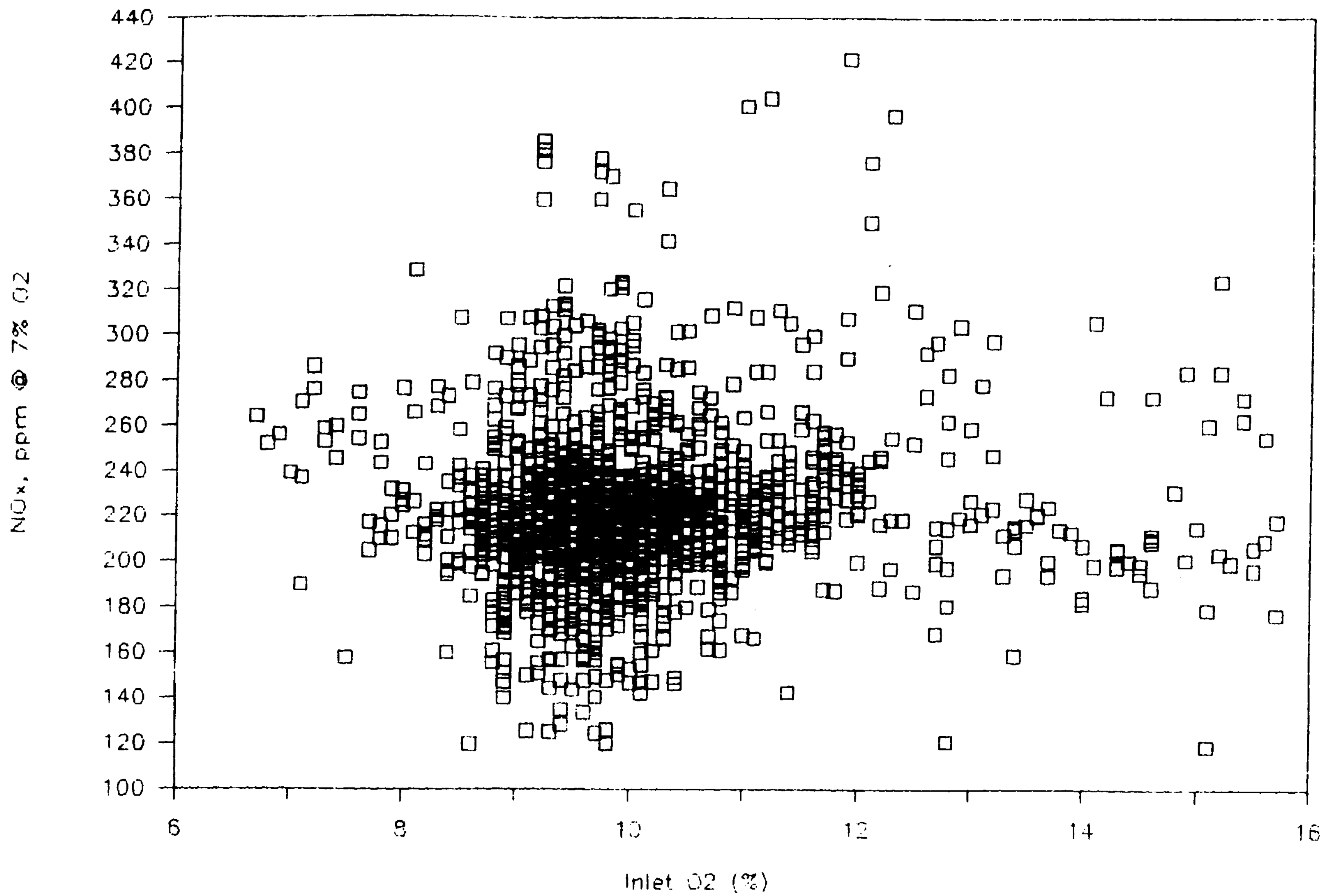

Figure 2-4. Long-term NO_X versus O_2 emissions for the Millbury MWC

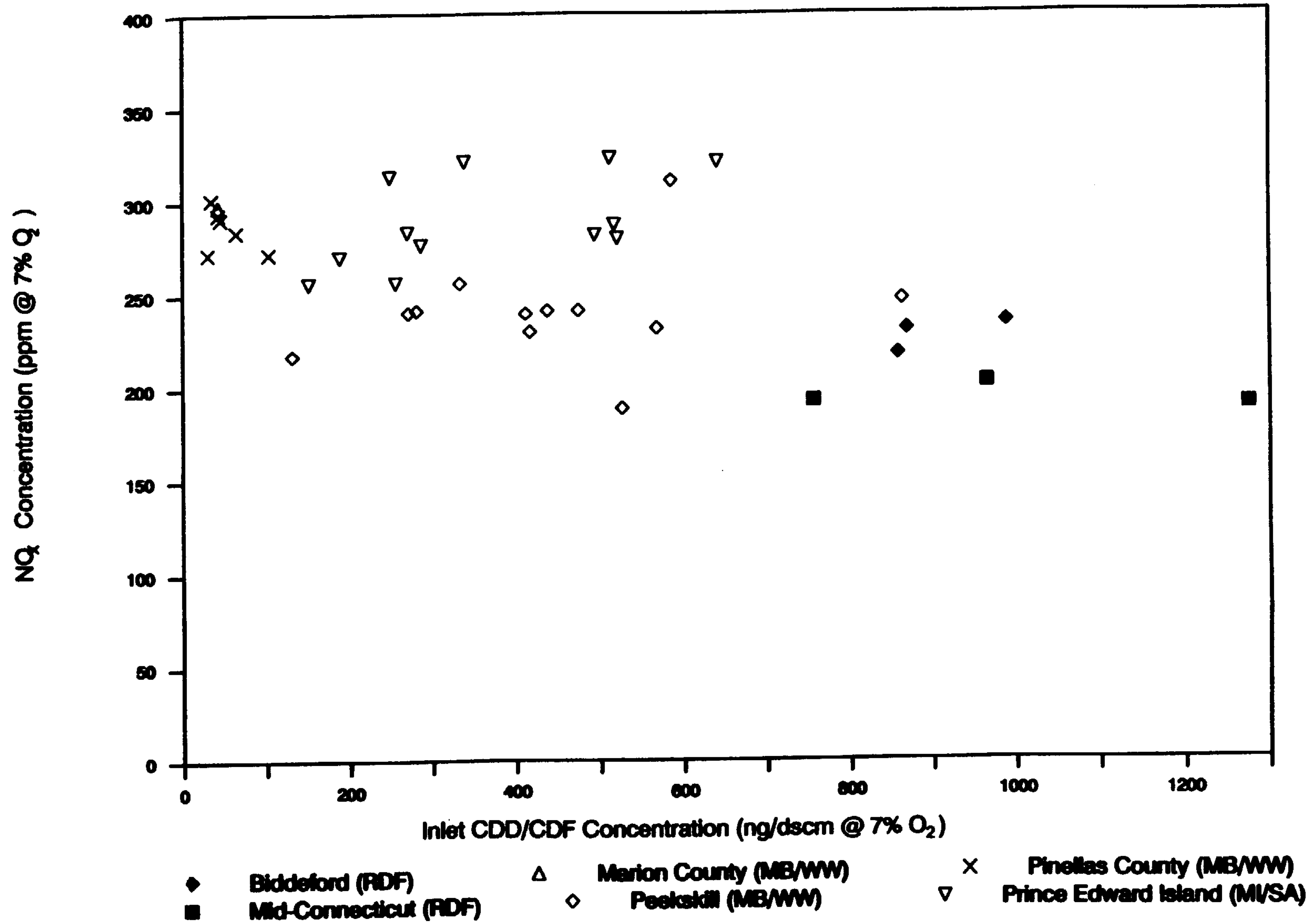

Figure 2-5. NO_X emissions versus CDD/CDF emissions

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3.0 NO_x EMISSION CONTROLS

There are two basic approaches to controlling NO_x emissions: (1) combustion modifications and (2) add-on controls. Combustion modifications include staged combustion, low excess air (LEA), and flue gas recirculation (FGR). Add-on controls include natural gas reburning, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and wet flue gas denitrification. Of these techniques, only combustion modifications, reburning with natural gas, SNCR, and SCR have been successfully demonstrated with MWC's or show significant potential for effective and economical NO_x control. Thus, detailed descriptions of NO_x controls will be limited to these technologies. With each description, measured NO_x emission reductions and possible problems with implementation on MWC's are also provided.

3.1 COMBUSTION CONTROLS

Combustion modifications can achieve moderate NO_x emission reductions from MWC's by limiting the amount of NO_x formed in the combustion process. Low excess air, staged combustion, and FGR are combustion controls for NO_x described in this section.

3.1.1 Low Excess Air and Staged Combustion

Low excess air and staged combustion can be used separately or together. With LEA, less air is supplied to the combustor than normal, lowering the supply of oxygen available in the flame zone to react with nitrogen in the combustion air. With staged combustion, the amount of underfire (primary) air is reduced, generating a starved-air region. By creating a starved-air zone, part of the fuel-bound nitrogen is converted to ammonia (NH_3). Secondary air to complete combustion is added as overfire (secondary) air. If the addition of overfire air is properly controlled, NH_3, NO_x, and O_2 react to form N_2 and water.

A Japanese mass burn/refractory combustor using automatic controls to obtain LEA/staged combustion conditions demonstrated up to 35 percent reduction in NO_x emissions over using manual controls.[1] At Marion County, the effects of low excess air and low and high overfire air were evaluated. The NO_x data from these tests are presented in Table 3-1. Compared to normal operating conditions at Marion County (75 percent excess air), LEA (40 percent excess air) conditions reduced NO_x emissions from 286 ppm to 203 ppm, a decrease of 29 percent. Under low load conditions, LEA reduced NO_x emissions from 257 ppm (at 70 percent excess air) to 195 ppm (at 58 percent excess air), a decrease of 24 percent. During tests of the combustor with only underfire air (low overfire air), but at normal excess air conditions, NO_x emissions decreased by 27 percent at low load (188 ppm versus 257 ppm) and 23 percent at normal load (220 ppm versus 286 ppm). During parametric combustor tests at Quebec City, use of low overfire air reduced NO_x emissions by 25 percent compared to tests conducted at similar load and excess air levels. The reason low overfire air generates less NO_x is not certain, but it may be at least partially caused by high excess air at the grate reducing the peak flame temperature, which in turn decreases thermal NO_x formation. NO_x measurements taken at Marion County during testing with high overfire air and normal load (276 ppm) and low load (252 ppm) were roughly equal to tests conducted at similar load and normal air distribution (286 ppm and 257 ppm, respectively). These data suggest that use of high overfire air may be ineffective in reducing NO_x emissions from mass burn waterwall combustors.

3.1.2 Flue Gas Recirculation

In FGR, cooled flue gas is mixed with combustion air, thereby reducing the oxygen content of the combustion air supply. The flame temperature is lowered and less oxygen is present in the flame zone, reducing thermal NO_x generation. At the Long Beach, CA, mass burn combustor, where FGR is used to supply 10 percent of the underfire air, reductions in NO_x emissions have been observed, although no quantitative results are available.[3] At the Kita facility in Tokyo, Japan, a Volund mass burn/refractory combustor, where FGR is used to supply 20 percent of the combustion air, NO_x reductions of 10 to 25 percent have been reported.[3] At higher FGR rates, little increase in NO_x reduction was observed. The modular excess-air combustors at Pigeon Point and Pittsfield are Vicon units that have FGR built into the system. In Vicon

TABLE 3-1. MARION COUNTY EMISSIONS VERSUS AIR SUPPLY

Air Supply[a]	Runs	Load (% of Full)	NO_x Emissions (ppm, 7% O_2)	Excess Air (%)	% NO_x Reduction[b]
Normal	1, 2, 10, 11a and 11b	100	286[c]	75	--
LEA	3a	95	203	40	29
LOA	4	98	220	74	23
HOA	5	103	276	73	4
Normal	6a	76	257	70	--
LEA	7	77	195	58	24
LOA	8	74	188	88	27
HOA	9	78	282	94	(10)[d]

[a]Tests where air supply was purposely varied are noted. LEA = low excess air; HOA = high overfire air; LOA = low overfire air.

[b]Compared to NO_x emissions at normal air supply and similar load.

[c]Average NO_x emissions for the 5 runs.

[d]Percent increase in NO_x emissions.

combustors, flue gas from ducting at the boiler exit (prior to flue gas cleaning) is injected into the primary combustion chamber. Recirculated flue gas supplies approximately 35 percent of the combustor air. Emissions of NO_x measured at Pigeon Point and Pittsfield range from 100-140 ppm at 7 percent O_2. There are no data available comparing NO_x emissions with and without FGR for a Vicon combustor.

Combustion modifications for NO_x control may not increase emissions of other pollutants.[4] However, if the modifications are not properly applied, higher emissions of CO, HC, and other products of incomplete combustion (PIC's) may result. For example, if the excess air is decreased too much, visible emissions and higher CO concentrations may result.[5] If too much flue gas is recirculated, the flame zone can become unstable, causing poor combustion and higher CO emissions.[6,7] Also, corrosion and slagging in the boiler may occur.

3.2 GAS REBURNING

Gas reburning is a NO_x control technique that overlaps combustion modification techniques. A schematic of the natural gas burning method applied to a mass burn combustor is shown in Figure 3-1. Low excess air is provided at the combustor grate, with recirculated flue gas introduced above the grate. Natural gas is added to this LEA zone to generate a fuel-rich zone. Air is supplied above the fuel-rich zone to complete combustion. This process is designed to reduce NO_x formation without increasing CO emissions.

Natural gas reburning at MWC's is a new technology being evaluated by the Gas Research Institute. The goal of gas reburning is to achieve up to 75 percent NO_x reduction. To date, most of the data on reburning are for pulverized coal-fired (PC) boilers.[8] Testing for MWC's is currently underway in a 6 tpd pilot-scale combustor. In the pilot-scale unit, NO_x emissions without gas reburning ranged from 190 to 260 ppm at 7 percent O_2. With gas reburning, the NO_x emissions were 110 to 125 ppm at 7 percent O_2, an average reduction of 50 percent. The maximum NO_x reduction measured was 60 to 70 percent. During these tests, 15 percent (heat input basis) natural gas, 15 percent flue gas recirculation (for mixing the natural gas), and 30 to 40 percent excess air were used. Neither CO nor hydrocarbon emissions increased with gas reburning.[10]

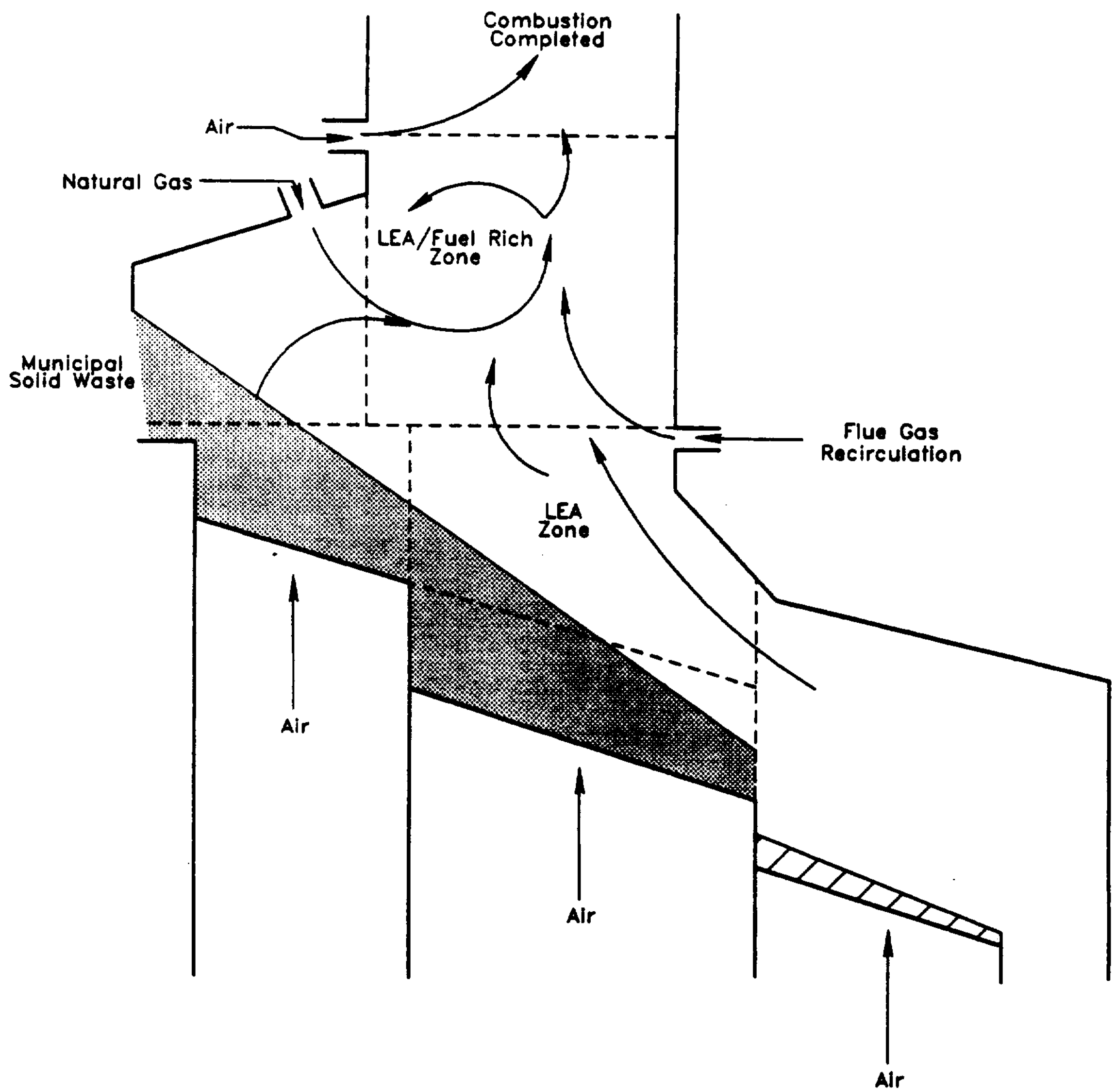


Figure 3-1. Gas Reburning for NO_x Control at a Mass Burn MWC.[9]

3.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction is an add-on control technology for NO_x removal. Ammonia (NH_3) is injected into the gas flue downstream of the boiler where it is mixed with the NO_x contained in the flue gas and passed through a catalyst bed. In the catalyst bed, NO_x is reduced to N_2 by reaction with NH_3. The overall reactions between NO_x and NH_3 are:

$$(1)\ 4\ NO + 4\ NH_3 + O_2 \longrightarrow 4\ N_2 + 6\ H_2O$$
$$(2)\ 2\ NO_2 + 4\ NH_3 + O_2 \longrightarrow 3\ N_2 + 6\ H_2O$$

The reactions between NO_x and NH_3 occur at temperatures of 375-750^oF, depending on the specific catalyst.

Selective catalytic reduction has been tested at coal, oil, and natural gas-fired facilities in the U. S. Reductions of NO_x emissions of 60 to 85 percent have been measured at these facilities with NH_3:NO_x molar ratios of 0.6 to 0.9 and temperatures between 570 and 750^oF.[11] Currently there are no applications of SCR to MWC's in the U. S. NO_x emission reductions of 26 to 86 percent have been measured at two Japanese mass burn MWC sites using special low temperature catalysts (V_2O_5 - TiO_2, temperatures of 375 to 535^oF).[12] The SCR system at the 65 ton/day MWC in Iwatsuki, Japan, demonstrated an average NO_x reduction of 77 percent (versus design of 80 percent) during two performance tests conducted approximately 1 and 2 months after plant startup. This SCR unit, located downstream of a spray dryer/fabric filter system, operated at an average temperature of 395^oF and a NH_3:NO_x molar ratio of 0.7. Data from these tests are reported in Table 3-2. At the Tokyo-Hikarigaoka 150 ton/day MWC, the SCR system demonstrated an average NO_x reduction of 44 percent at a temperature of 475^oF and a NH_3:NO_x molar ratio of 0.57. These tests were conducted approximately 3 months after startup; the data are presented in Table 3-3. This SCR unit was retrofit between an ESP and a wet scrubber. Because of space constraints, the SCR unit was sized for 51 percent NO_x removal.

There are several operating considerations with SCR. First, the SCR operating temperature at both Iwatsuki and Tokyo-Hikarigaoka exceed the

TABLE 3-2. RESULTS OF TESTING OF SCR SYSTEM AT IWATSUKI, JAPAN

Test Date	Unit No.	Run No.	SCR Inlet Temperature (°F)	Molar Ratio (NH_3:NO_x)	NO_x Concentration (ppm at 7% O_2) Inlet	NO_x Concentration (ppm at 7% O_2) Outlet	NO_x Removal Efficiency (%)
2-19-87	1B	1	385	0.85	192	47.2	75.4
		2	399	0.76	201	45.9	77.2
		3	396	0.65	270	40.9	84.9
3-6-87	1B	4	396	0.76	172	23	86.4
		5	392	0.80	203	47	76.9
		6	392	0.64	250	56	77.5
2-19-87	2B	1	388	0.79	201	40.0	80.2
		2	388	0.66	304	59.3	70.2
		3	401	0.61	216	64.3	70.2
3-6-87	2B	4	401	0.71	156	25	84.0
		5	405	0.68	187	70	62.5
		6	397	0.53	203	45	77.7
Average 1B			393	0.74	215	43	79.7
Average 2B			397	0.66	211	51	74.1
Average Overall			395	0.70	213	47	76.9

TABLE 3-3. RESULTS OF TESTING OF SCR SYSTEM AT TOKYO-HIKARIGAOKA, JAPAN

Test Date	Run No.	SCR Inlet Temperature (°F)	Molar Ratio (NH_3:NO_x)	Outlet NH_3 Concentration (ppm)	NO_x Concentration (ppm at 7% O_2) Inlet	Outlet	NO_x Removal Efficiency (%)
3-17-87	1	478	0.44	2.6	150	98	34
	2	478	0.80	15	148	73	51
3-18-87	3	475	0.43	0.5	166	123	26
	4	471	0.69	6.1	162	94	42
3-19-87	5	475	0.56	13	153	66	57
	6	475	0.50	14	158	73	54
Average		475	0.57	8.5	156	83	44

fabric filter outlet temperature needed to achieve maximum control of CDD/CDF, HCl, and SO_2. As a result, either flue gas reheat will be needed or reduced control of CDD/CDF, HCl, and SO_2 will occur. Second, performance of SCR can be detrimentally affected by catalyst poisoning by either metals or acid gases. Also, entrained particulate can blind or deactivate the catalyst. Third, because ammonia is injected into the flue gas, ammonia emissions can result. In a properly operated system, ammonia emissions are typically less than 10 ppm.[13] At the Tokyo-Hikarigaoka MWC, outlet ammonia emissions averaged 8.5 ppm and ranged from 0.5 to 14 ppm. Fourth, depending on the location of the catalyst bed (i.e., after the economizer or after particulate/acid gas removal), flue gas reheat may be necessary to reach the desired catalyst operating temperature. Flue gas reheat can be a significant expense.[14]

3.4 SELECTIVE NON-CATALYTIC REDUCTION

Selective non-catalytic reduction (SNCR) refers to add-on NO_x control techniques which reduce NO_x to N_2 without the use of catalysts. These techniques include Exxon's Thermal DeNO_x, which uses injection of ammonia; the Electric Power Research Institute's NO_xOUT process, which injects urea and chemical additives; and EMCOTEK's two-stage urea/methanol injection process. To date, only Thermal DeNO_x has been demonstrated on MWC's in the U. S., although the other techniques have been tested in Europe and Japan. Because of this, discussion of SNCR techniques focuses on Thermal DeNO_x.

With Thermal DeNO_x, ammonia is injected into the upper furnace area of the combustor. Ammonia and NO_x react according to the following competing reactions:

$$(1)\ 4\ NO + 4\ NH_3 + O_2 \ \text{---->}\ 4\ N_2 + 6\ H_2O$$
$$(2)\ 4\ NH_3 + 5\ O_2 \ \text{---->}\ 4\ NO + 6\ H_2O$$

At 1,600 to 1,800^oF, the first reaction dominates and NO_x is reduced to N_2. Above 2,000^oF, the second reaction dominates and NH_3 is oxidized to NO. Below 1,600^oF, both reactions proceed slowly and NH_3 remains unreacted. Reductions as high as 65 percent are projected for MWC's by Exxon.[15]

Because of the viability in combustion characteristics of MSW, furnace temperatures in the upper furnace can vary rapidly. This necessitates installation of ammonia injectors at several furnace elevations to assure injection at proper temperatures. The sensitivity of ammonia-based SNCR reactions to temperature is one of the primary reasons behind development of the urea-based NO_xOUT and EMCOTEK processes.

Thermal $DeNO_x$ has been applied at several MWC's in Japan and at three state-of-the-art mass burn/waterwall combustors in California (Commerce, Stanislaus County, and Long Beach). Each of the operating MWC's in the U. S. using Thermal $DeNO_x$ is summarized in Table 3-4.

The Commerce Refuse to Energy Facility, in Commerce, California, consists of one mass burn waterwall Foster-Wheeler combustor with a Detroit Stoker grate. The design capacity is 380 tons/day MSW. Emissions are controlled by Exxon's Thermal $DeNO_x$ system, and a Teller/American Air Filter (AAF) spray dryer and fabric filter. The Thermal $DeNO_x$ system injects ammonia into the upper combustion chamber to reduce NO_x emissions to elemental nitrogen and water. The flue gases then enter a cyclonic separator or remove large particles before entering the up-flow SD. In the SD, lime slurry is injected through two-fluid nozzles at a design feed rate of 600 lb/hr of lime. A residence time of 10 seconds is provided in the SD vessels. The design flue gas temperature at the SD outlet is 270^{o}F. Tesisorb® is injected into the flue gas after leaving the SD to remove additional acid gases and to assist conditioning of the filter cake. The FF uses reverse air cleaning with eight compartments of 156 fiberglass bags each. The design net air-to-cloth ratio is 2 acfm/ft^2 with two compartments off-line and a flue gas flow of about 85,000 acfm. The flue gas leaves the FF and exists through a 150-foot high stack.

The Southeast Resource Recovery Facility in Long Beach, California consists of three identical L. & C. Steinmuller GmbH waterwall combustors, each with a capacity of 460 tons/day MSW. Each combustor has Thermal $DeNO_x$ and flue gas recirculation for NO_x control. Other pollutants are controlled downstream from the boiler with a spray dryer/fabric filter system manufactured by Flakt-Peabody Process Systems. In the spray dryer, lime

TABLE 3-4. EXISTING THERMAL DENO$_x$ FACILITIES IN UNITED STATES

Facility Location	Startup Date	Combustor Type[a]	Number of Combustors	Combustor Size, tpd	APCD Type[b]	NO_x Emissions, ppm @ 7% O_2	Estimated NO_x Reduction, Percent
Commerce	2/87	MB/WW	1	300	SD/FF	119[c]	44
Long Beach	7/88	MB/WW	3	460	SD/FF	56[d]	50
Stanislaus Co.	8/88	MB/WW	2	400	SD/FF		
Unit 1						93[e]	69[e]
Unit 2						113[e]	63[e]

[a]MB/WW = mass burn/waterwall.

[b]SD/FF = spray dryer/fabric filter.

[c]Average of 10 short-term optimization tests at NH_3 injection rate of 2.4 lb/ton (see Table 3-5).

[d]Average of three compliance tests.

[e]At 12 percent CO_2.

slurry is injected through a rotary atomizer, with the rate of slurry addition controlled by an SO_2 monitor/controller at the stack. The amount of dilution water in the lime slurry is controlled to maintain temperature at the outlet of the SD. Flue gas exiting the SD flows through the reverse-air FF. Design flue gas flow to each FF is 118,000 acfm at 285^{o}F. Each FF has 10 compartments of teflon-coated fiberglass bags and a net air-to-cloth ratio of 1.8 acfm/ft^2. Ducting is provided to route flue gas from one FF to another if one unit goes down. Flue gas is exhausted through a common stack.

The Stainslaus Waste-to-Energy Facility in Crows Landing, California consists of two identical Martin GmbH waterwall combustors, each capable of combusting 400 ton/day MSW. Each combustor is equipped with Exxon's Thermal $DeNO_x$ (ammonia injection) for NO_x control. Emissions are controlled downstream of the boiler with a Flakt spray dryer/fabric filter system. In the SD, slaked lime slurry is injected through two-fluid nozzles, with the amount of slurry controlled according to the stack SO_2 concentration and the dilution water flow controlled according to the SD outlet temperature. A residence time in the SD of 15 seconds is used to dry the slurry and obtain a flue gas temperature of 285^{o}F at the SD outlet. Flue gas exiting the SD flows through the pulse-jet FF at 94,000 acfm and 285^{o}F. The FF has six compartments of teflon-coated fiberglass bags (1,596 bags total) and a net air-to-cloth ratio of 3.2 afm/ft^2.

Because of the limited operating time of these units, long-term performance and reliability data are limited. Available performance data are based mainly on short-term compliance testing using continuous emission monitors and observations by plant operating personnel.

During initial compliance testing at Commerce in June 1987, NO_x averaged 62 ppm at an ammonia injection rate of 2.7 lb/ton refuse (2.0 NH_3:NO_x molar ratio).[16] Due to concerns regarding potential increases in NH_3 slip, however, the system normally has NO_x emissions of around 90 ppm, and an ammonia injection rate of 2.0 lb/ton refuse (1.45 NH_3:NO_x molar ratio).[17]

Additional testing at the Commerce facility, performed in June 1988, showed variations in performance with ammonia injection location and NH_3:NO_x molar ratio.[18] These data are summarized in Table 3-5. The objective of

TABLE 3-5. SUMMARY OF NO_x REDUCTIONS AT COMMERCE OPTIMIZATION TEST[18]

Injection Location	NH_3 Rate		Average NH_3 Molar Ratio	Number of Tests	Controlled NO_x Emissions (ppm @ 7% O_2)			NO_x Reduction (%)[b,c]		
	lb/hr	lb/ton[a]			Average	High	Low	Average	High	Low
Top Row	15	1.2	0.85	5	117	145	105	22.3	27.0	14.5
	30	2.4	1.53	10	92	107	63	43.9	57.5	21.9
	45	3.6	2.36	11	93	148	58	44.0	62.0	18.0
Bottom Row	15	1.2	0.89	2	126	136	116	11.8	12.5	11.0
	30	2.4	1.88	2	120	125	114	19.8	24.4	15.3
	45	3.6	2.36	2	94	107	80	42.1	48.4	35.7

[a]Pounds per ton refuse fed. Calculated based on 300 tpd capacity of combustor.

[b]Based on NO_x emissions with Thermal DeNO_x turned off for each test.

[c]Percent NO_x reductions do not correspond directly to those for NO_x emissions.

these tests was to determine the optimum ammonia injection elevation. During testing, the ammonia injection location was varied between a top row and a bottom row of injection nozzles. The ammonia injection rate was also varied, ranging from 0 to 3.6 lb NH_3 per ton refuse at each injection location. Injection through the top row of nozzles generally resulted in lower NO_x emissions than injection through the bottom row of nozzles. At an NH_3 injection rate of 1.2 lb/ton (average NH_3:NO_x molar ratio of 0.85) through the top row of nozzles, measured NO_x emissions averaged 117 ppm (22 percent NO_x reduction). At injection rates of 2.4 and 3.6 lb/ton NH_3 (average NH_3:NO_x molar ratio of 1.5 and 2.4, respectively) through the top row of nozzles, NO_x emissions averaged 92 ppm (44 percent reduction), although there was significant scatter in the data. At the NH_3 injection rate of 3.6 lb/ton, NO_x emissions were both higher and lower than at the injection rate of 2.4 lb/ton.

After completion of these tests, refractory was installed in the lower furnace at Commerce to correct waterwall corrosion problems in this area. As a result, less heat is removed from the combustion gases in the lower furnace and gas temperatures at the two original ammonia injection elevations frequently exceed those needed for SNCR. To correct for these modifications in combustor design, two new rows of ammonia injectors have been installed above the existing rows. The Thermal $DeNO_x$ at Commerce is currently operated from the control room by monitoring furnace conditions and NO_x levels. The best system performance is achieved with ammonia injection through one or more of the upper three injector rows depending on real-time monitoring of combustor conditions and NO_x levels. Maximum 1-hour NO_x emissions from February through May 1989 were less than 150 ppm at 7 percent O_2 on all but 6 days (out of 110 days total). All of the 24-hour averages were less than 120 ppm at 7 percent O_2.[19]

Emissions of NO_x measured during three short-duration tests on Unit 1 at the Long Beach facility averaged 56 ppm at 7 percent O_2 with the Thermal $DeNO_x$ system operating normally. Three runs performed 1 month later without Thermal $DeNO_x$ measured average NO_x emissions of 68 ppm at 7 percent O_2, suggesting a NO_x reduction of roughly 20 percent due to Thermal $DeNO_x$. NO_x

measurements during both test periods are based on grab sampling and wet chemistry analysis using South Coast Air Quality Management District (SCAQMD) Method 7.1. These uncontrolled NO_x levels are significantly lower than typically measured by the plant CEM system.[20] When neither the FGR or Thermal $DeNO_x$ systems are in operation, NO_x emissions measured by the plant CEMS are typically 190-230 ppm at 7 percent O_2. With FGR only, NO_x emissions based on the plant CEMS are typically 160-190 ppm. When both FGR and Thermal $DeNO_x$ are operated, NO_x emissions are reported to be consistently less than 120 ppm, and frequently less than 50 ppm. These data indicate that the Thermal $DeNO_x$ system reduces NO_x emissions at Long Beach by 30-70 percent.

At the Stanislaus County MWC, three tests were performed on each of the facility's two units.[21] Without ammonia injection, the NO_x emissions from Unit 1 averaged 297 ppm at 12 percent CO_2. With ammonia injection of 29 lb/hr (1.7 lb NH_3 per ton MSW), the NO_x emissions averaged 93 ppm at 12 percent CO_2, a reduction of 69 percent. Similar results were obtained for Unit 2, where NO_x emissions averaged 304 ppm at 12 percent CO_2 without ammonia injection and 113 ppm at 12 percent CO_2 with an ammonia injection rate of 25 lb/hr (1.5 lb NH_3 per ton MSW), a reduction of 63 percent.

As with SCR, there are potential problems associated with Thermal $DeNO_x$. Ammonia or ammonium chloride emissions may result when the NH_3 is injected outside the desired temperature window, at a higher than normal rate, or when residual HCl levels in the stack exceed roughly 5 ppm. At the Long Beach MWC, a detached ammonium chloride plume has been observed downwind of the stack when the Thermal $DeNO_x$ is used. At the Stanislaus County MWC, an ammonium chloride plume was observed at an NH_3 injection rate 50 percent higher than the normal feed rate of 1.5-1.7 lb/ton.[22] At the Commerce MWC, ammonia emissions following the unit's spray dryer/fabric filter have not been measured above 2 ppm at 7 percent O_2. However, an ammonium chloride plume is frequently present.

Corrosion of the boiler tubes by corrosive ammonia salts which are formed from unreacted ammonia and sulfur dioxide or hydrogen chloride has been hypothesized to be a potential problem with Thermal $DeNO_x$. However, no boiler corrosion problems attributable to ammonia salts have been observed with the U. S. systems during the limited amount of operating time.[24,25] In Japanese MWC's ammonia is generally injected into refractory sections, not in boiler tubes where corrosion can occur.

Increased CO emissions with ammonia injection has also been suggested as a potential problem with Thermal $DeNO_x$.[26] At Commerce, measured CO emissions while the $DeNO_x$ was operating normally (15 ppm at 7 percent O_2) were essentially the same as the CO emissions without the $DeNO_x$ (14 ppm at 7 percent O_2).[27]

A recently identified concern with Thermal $DeNO_x$ is that the ammonia injected into the flue gas may reduce control of mercury emissions by a spray dryer/fabric filter. Outlet mercury emissions from MWC's with spray dryer/fabric filter systems are presented in Table 3-6. Compliance tests at Commerce (June 1987),[27] Long Beach (November 1988),[28] and Stanislaus County (December 1988)[29] showed relatively high mercury emissions (180 to 900 ug/dscm at 7 percent O_2) compared to facilities without SNCR (Biddeford, Quebec City, and Mid-Connecticut). At Commerce, mercury concentrations prior to and following the spray dryer/fabric filter were simultaneously measured during a single run and indicated little or no removal of mercury. During the tests at Commerce, portions of the probe rinse from the spray dryer/fabric filter inlet and outlet samples were inadvertently discarded. As a result, the calculated concentrations and removal efficiencies are estimates. However, because mercury is generally volatile, relatively little mercury was probably present in the discarded samples. Thus the calculated values are believed to be representative. Uncontrolled mercury concentrations were not measured at Stanislaus County and Long Beach, but the measured outlet emissions suggest little removal of mercury. Because these three facilities have spray dryer/fabric filter systems as well as ammonia injection for NO_x control, it has been suggested that the poor mercury removals may be due to the ammonia in the flue gas.

A possible explanation for the impact of Thermal $DeNO_x$ on mercury control is that mercury is normally in a combined ionic form (principally $HgCl_2$) that can absorb or condense onto particulate matter at the low

TABLE 3-6. OUTLET MERCURY EMISSIONS MEASURED FROM SPRAY DRYER/FABRIC FILTER SYSTEMS

Facility Location	APCD Type[a]	Inlet Temperature to Fabric Filter, °F	Inlet PM Emissions, gr/dscf @ 12% CO_2	Inlet CDD/CDF Emissions, ng/dscm @ 7% O_2	Outlet Mercury Emissions, ug/dscm @ 7% O_2
Commerce (1)	SD/FF/SNCR	270	1.8	28.1	200 - 940
Commerce (2)	SD/FF/SNCR	NA[b]	2.01	NA	39.4
Commerce (2)	SD/FF/SNCR	NA	1.23	619	67.9
Long Beach	SD/FF/SNCR	300	1.58	NM[c]	180
Stanislaus County					
Unit 1	SD/FF/SNCR	287	NM	NM	499
Unit 2	SD/FF/SNCR	292	NM	NM	462
Mid-Connecticut	SD/FF	277	2.41	1,019	50
Marion County	SD/FF	280	0.88	43.0	239
Biddeford	SD/FF	278	3.2	903	0
Quebec City	SD/FF	283	2.92	1,960	14.7

[a] SD/FF = spray dryer/fabric filter.
SNCR = Selective non-catalytic reduction.

[b] NA = not available.

[c] NM = not measured.

operating temperatures of the fabric filter (less than 300^{o}F).[30] By injecting ammonia into the flue gas, however, pockets of reducing atmosphere may form which reduce mercury to an elemental form, which is more volatile and difficult to collect.

However, data collected more recently at Commerce (May 1988) demonstrated mercury removals of 91 percent while firing a mixture of 60 percent commercial refuse and 40 percent residential refuse and 74 percent while firing a mixture of 95 percent commercial refuse and 5 percent residential refuse.[31] During both of these tests the ammonia injection system was operating. These test results indicate that ammonia injection may not be the reason for the observed low mercury removals.

Another theory gaining acceptance regarding the removal of mercury is that carbon in the flue gas enhances adsorption of mercury and that Thermal DeNO$_x$ has no effect.[32] This theory suggests that the poor removals of mercury at the MWC's with Thermal DeNO$_x$ are a result of good combustion leaving little carbon in the fly ash onto which the mercury could adsorb. In Figure 3-2, mercury removal efficiency from spray dryer/fabric filter systems operating at 300^{o}F or less is plotted as a function of the PM concentration at the combustor exit. The data suggest increased mercury removal with increasing inlet PM concentration. Mercury emissions as a function of inlet PM are shown in Figure 3-3. The trends are similar to those in Figure 3-2. The data from the 1987 test at Commerce represent maximum estimated emissions and are separated by run because the results varied widely.

Little direct data are available on the carbon content of the fly ash from the facilities in Table 3-6. However, it is expected that CDD/CDF concentrations at the combustor exit are indicative of good combustion, and thus provide a surrogate measure for the carbon content of the fly ash.[33] Data on mercury removal efficiency and mercury outlet concentration versus CDD/CDF at the combustor exit are shown in Figures 3-4 and 3-5, respectively. Both of these figures support the theory that reduced carbon content in the fly ash increases mercury emissions.

Because of the limited amount of mercury emissions data from MWC's with Thermal DeNO$_x$ and the apparent strong relationship between fly ash

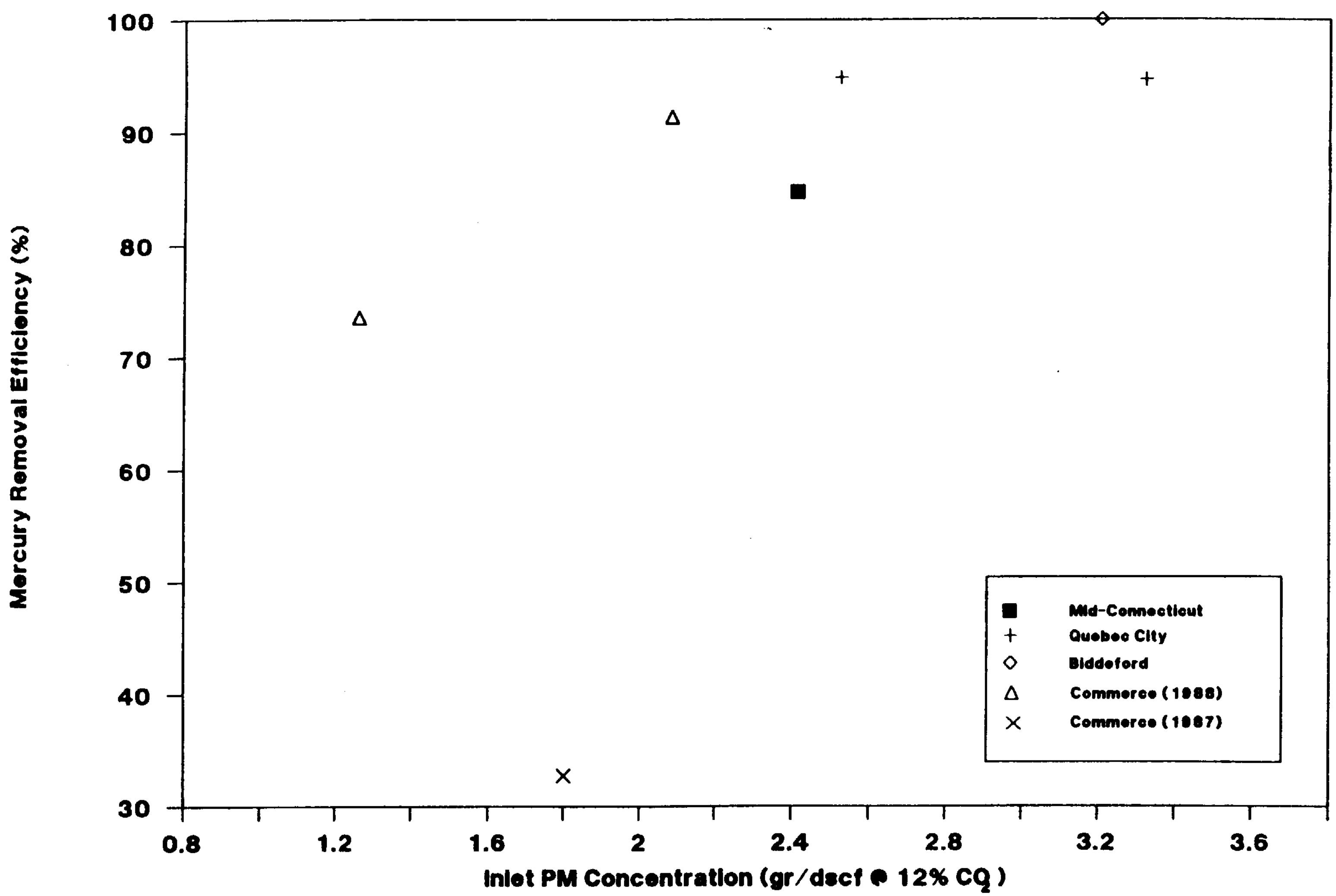
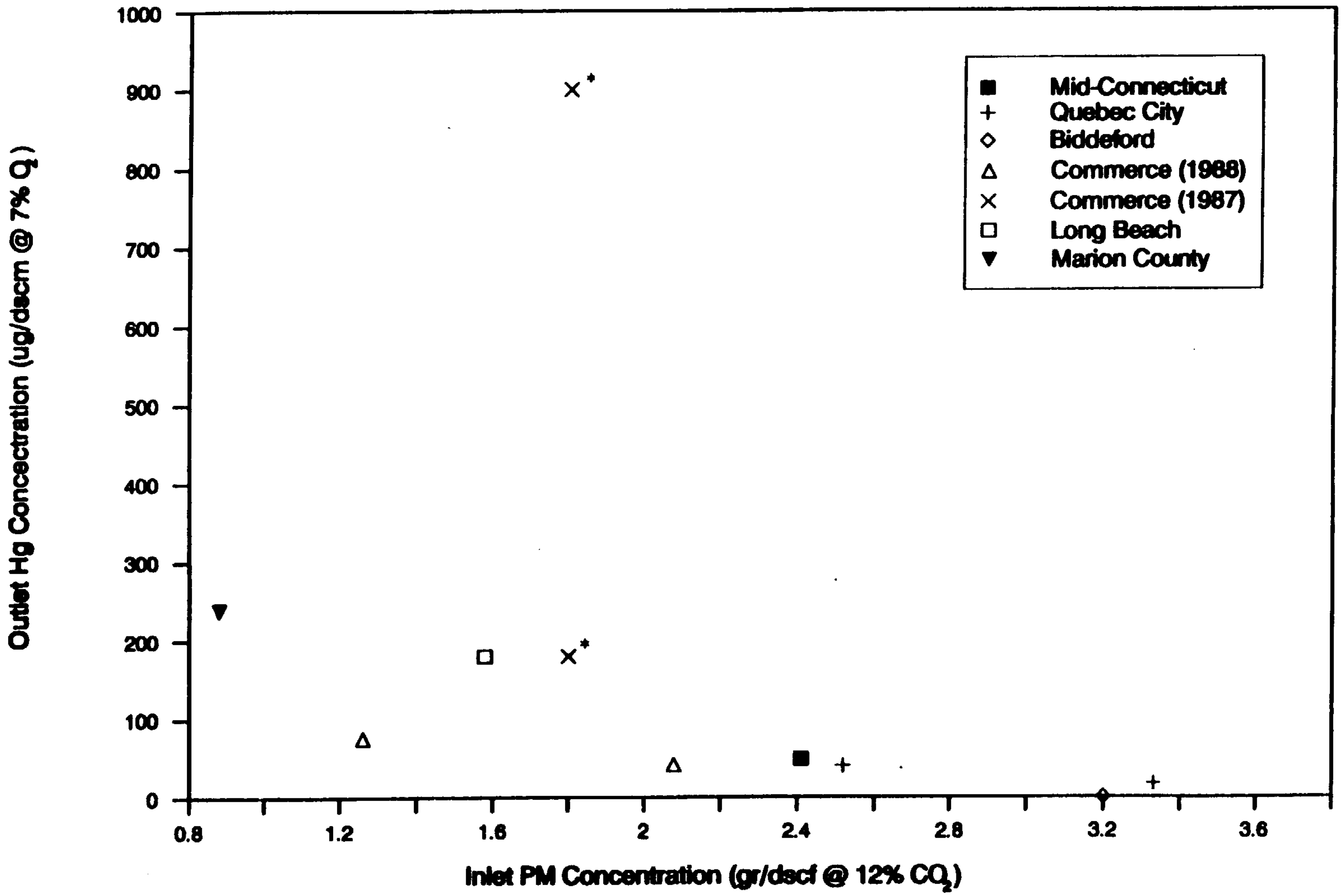


Figure 3-2. Effect of inlet PM on mercury removal efficiency for MWCs with SD/FF systems.



* Individual runs during same test period at Commerce.

Figure 3-3. Effect of inlet PM on mercury emissions for systems with spray dryer/fabric filter systems

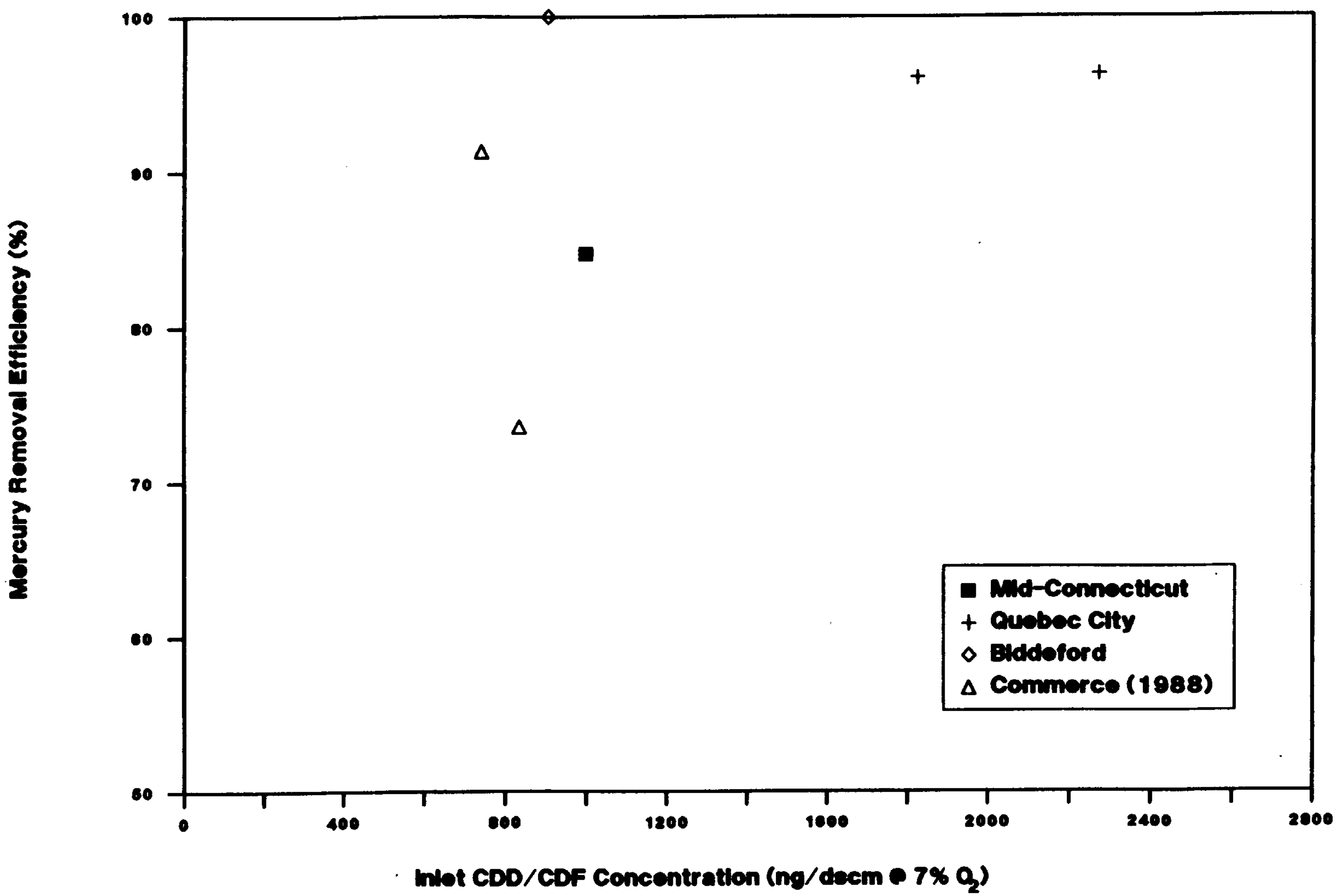


Figure 3-4. Effect of inlet CDD/CDF on mercury removal efficiency for MWCs with spray dryer/fabric filter systems

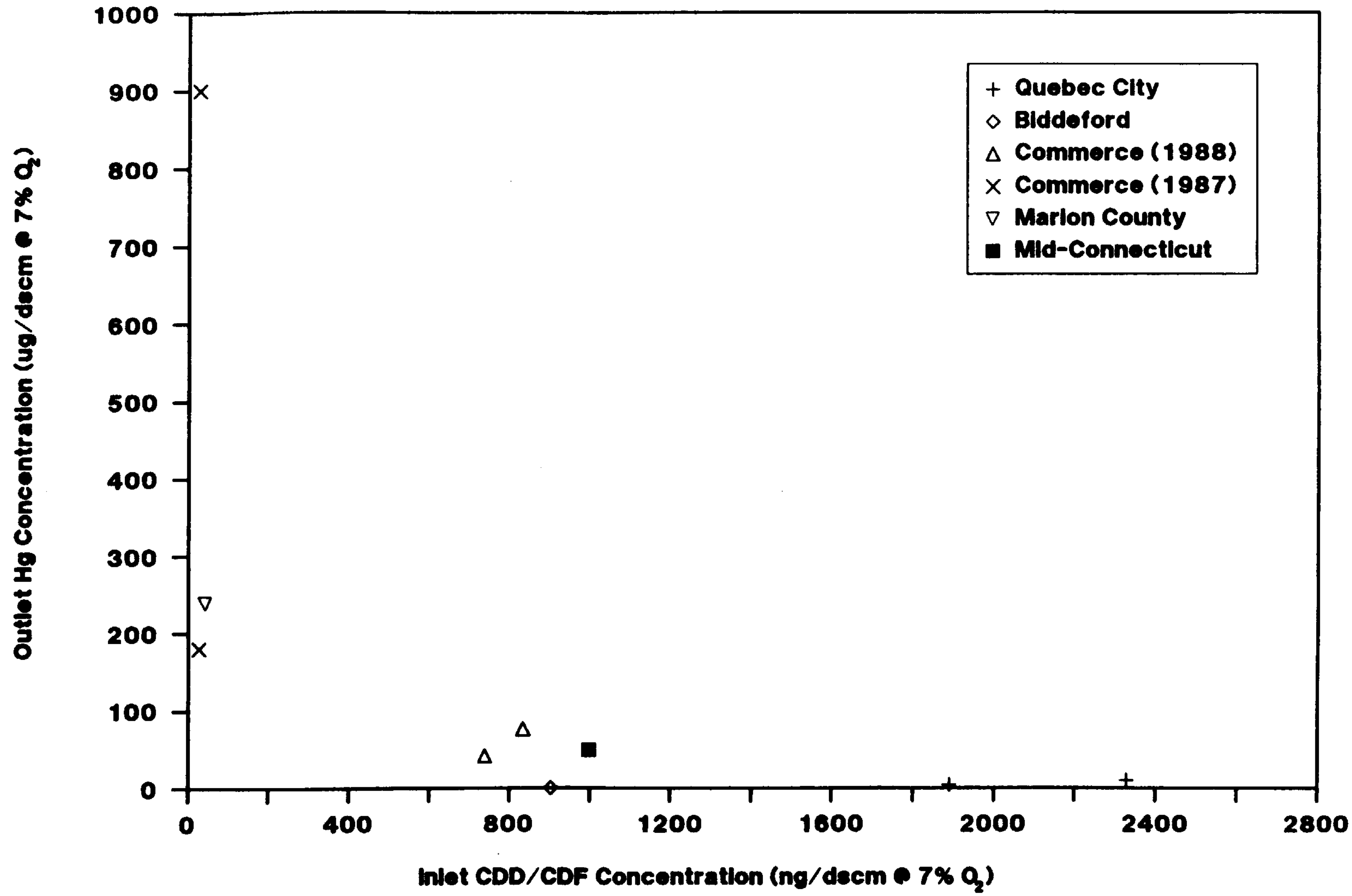


Figure 3-5. Effect of inlet CDD/CDF on mercury emissions for MWCs with spray dryer/fabric filters systems

concentration and carbon content versus mercury control, the hypothesized detrimental effect of Thermal $DeNO_x$ on mercury control by a spray dryer fabric filter cannot be proved with certainty.

3.5 SUMMARY OF NO_x EMISSION CONTROLS

There are advantages and disadvantages to the control of NO_x emissions from MWC's with both combustion modifications and add-on NO_x controls. Combustor modifications, such as low excess air and staged combustion, can be implemented relatively easily without substantial additional cost. However, consistent and quantifiable NO_x emission reductions have not been demonstrated with these technologies. The highest potential NO_x emission reduction appears to be about 30 percent. Higher NO_x reductions would result in increased CO, HC, or other PIC emissions.

Natural gas reburning offers the potential to achieve 60 to 70 percent NO_x reductions without increasing CO emissions. The technology has only been tested on a pilot-scale MWC, however, and further testing needs to be done before applying reburning to full-scale MWC's.

Selective catalytic reduction appears able to yield high NO_x reductions. Reductions of NO_x at a full-scale MWC in Japan averaged nearly 80 percent, with a low of 62.5 percent measured for one run. However, catalyst poisoning and deactivation may substantially decrease performance with time.

Thermal $DeNO_x$ has been used on three MWC's in the U. S. Reductions of NO_x emissions during short-term tests may be as high as 65 percent, but can vary widely during normal operation. Controlled NO_x emissions of 150 ppm at 7 percent O_2 or less are consistently achievable with SNCR for long- and short-term tests. Because of the significant variability in Thermal $DeNO_x$ performance over time and the lack of CEM data, it is not currently possible to relate measured NO_x emission reductions during short-term compliance tests to long-term performance levels. Visible plume formation may occur as combustor operating conditions vary. Uncertainty also exists regarding the possible relationship between Thermal $DeNO_x$ and mercury emissions.

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4.0 COST PROCEDURES

Procedures are developed in this section for estimating capital and annual operating costs for applying Thermal DeNO$_x$ to new MWC's. As discussed in Section 3.0, Thermal DeNO$_x$ is a selective noncatalytic reduction (SCNR) technique for controlling NO$_x$ emissions which is being commercially used by three full-scale MWC's in California. To be consistent with other cost analyses performed for this regulatory development, costs for Thermal DeNO$_x$ are presented in December 1987 dollars.[1,2] Section 4.1 presents the procedures for estimating capital costs, and Section 4.2 presents the procedures for estimating annual operating costs. The procedures presented in both sections will be used to estimate costs of Thermal DeNO$_x$ for twelve 111(b) model plants in Section 5.0. Each model plant represents a subcategory of new MWC's. Each subcategory represents a different type and size of MWC expected to be built in the future. It should be emphasized that these procedures provide "study estimates" (i.e., $\pm$30 percent accuracy) of Thermal DeNO$_x$ costs for an individual application.

4.1 CAPITAL COST PROCEDURE

Table 4-1 presents the procedure for estimating capital costs for Thermal DeNO$_x$ applied to new MWC plants. The total capital investment includes direct purchased costs for equipment, indirect and contingency costs, licensing (royalty) fee, preproduction costs, and NO$_x$ monitoring equipment costs. The direct purchase costs include costs for the following equipment: a low-pressure air compressor, ammonia storage tank, ammonia vaporizer, injection nozzles, piping, and associated instrumentation. Indirect costs include field labor overheads, erection fee, and contractors' engineering and design fees. The contingency cost accounts for:
(a) unforeseen expenses that may occur such as equipment modification, increases in field labor costs, increases in startup costs, etc. and
(b) risks associated with meeting performance guarantees and the operating experience level of the technology. A licensing fee charged by the process vendor (Exxon Research and Engineering Company) is also included in the total capital costs. Preproduction costs include operator training, equipment

TABLE 4-1. PROCEDURES FOR ESTIMATING CAPITAL COSTS FOR THERMAL $DeNO_x$ APPLIED TO NEW MWC PLANTS[a,b]

Direct Costs, 10^3 \$ = 0.444 $(Q * N)^{0.621}$ + 151

Indirect Costs, 10^3 \$ = 0.33 direct costs + 10

= 0.147 $(Q * N)^{0.621}$ + 60

Contingency, 10^3 \$ = 20% of direct and indirect costs

License Fee, 10^3 \$ = 3.35 + 7.01 x 10^{-4} * Q * N

Preproduction, 10^3 \$ = 2% of the sum of the direct capital, indirect capital, and contingency + one month of the direct operating cost at full load excluding monitors

NO_x Monitor, 10^3 \$ = 24 * N

Total Capital Investment = Direct Costs + Indirect Costs + Contingency + License Fee + Preproduction + NO_x Monitor

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[a]Costs are in December 1987 dollars.

[b]Q = 125 percent of the calculated flue gas flowrate per combustor at 450^{o}F, acfm.
N = number of combustors.

checkout, extra maintenance, and inefficient use of chemicals and other materials during plant startup. The total capital investment includes separate NO_x monitoring equipment per combustor to ensure continuous emissions compliance.

Table 4-2 presents the capital cost data base used to develop the cost procedures. The data base contains capital estimates for Thermal $DeNO_x$ applied to 12 proposed mass burn/waterwall MWC facilities, ranging in size from 150 to 3,000 tpd. Most of these cost estimates were provided by Exxon and none of them contained any itemization of equipment or other costs. Only one data source reported actual flue gas flowrate as shown in Table 4-2. The flue gas flowrates of the other plants were estimated assuming an excess air level of 80 percent. These flue gas flowrates represent typical conditions associated with new mass burn/waterwall facilities (see Table 5-1 in this report). It is assumed that the costs for Thermal $DeNO_x$ applied to mass burn/waterwall combustors are similar to those for the other combustor types, since NO_x emissions for mass burn/waterwall combustors are within the range for all other combustor types as discussed in Section 2.0. Sections 4.1.1, 4.1.2, and 4.1.3 discuss the bases and rationale for the capital cost procedure.

4.1.1 Direct Capital Cost

Table 4-3 presents the direct capital costs from Table 4-2 for the 12 mass burn/waterwall facilities corrected to December 1987 dollars using the Chemical Engineering Plant Cost Index. As shown by Table 4-3, no apparent trend can be observed between direct capital costs and plant size either in tpd or acfm.

To better define direct and indirect costs, itemized capital cost data were obtained from Exxon and Ogden Martin Systems, Inc. (the developer of the Stanislaus County MWC plant in California that is equipped with Thermal $DeNO_x$) for a 500 tpd plant consisting of two mass burn/waterwall combustors.[13] These two cost estimates are presented in Table 4-4. For engineering equipment costs, the Ogden Martin costs are consistently higher. The ammonia CEM and level of safety equipment included in the Ogden Martin

TABLE 4-2. CAPITAL COSTS DATA FOR THERMAL $DeNO_x$ APPLIED TO MASS BURN/WATERWALL MWC'S

Total Plant Capacity, tpd	Total Plant Flue Gas Flowrate acfm	Direct Capital Costs, $1,000	Indirect Capital Costs, $1,000	Total Capital Costs Costs, $1,000[a]	License Fee, $1,000	Design NO_x Reduction, %	Cost Basis, Quarter (year)	Reference
150	34,162	150	220	375	45	50	4th (1987)	3
500	113,873	700	270	970	100	60	4th (1988)	3
500	113,873	654	351	1,010	100	40	3rd (1988)	4
500	115,500[b]	987	917	1,900[c]	96	36	3rd (1988)	5
650	148,035	315	682	997	158	NA[d]	3rd (1988)	6
800	182,197	300	450	750	158	55	3rd (1986)	6
960	218,636	291	221	512	195	36	3rd (1988)	3
1,000	227,746	NA	NA	960	NA	65	3rd (1988)	7
1,200	273,295	NA	NA	2,660	NA	NA	1st (1988)	8
1,440	332,970[b]	1,609	1,136	2,745	355	36	3rd (1988)	9
1,500[e]	218,636	645 (674)	295 (344)	840 (1,018)	296	50	1st (1987)	3
3,000	683,239	1,455	3,147	4,600	729	NA	3rd (1988)	8

[a]Excludes the licensing fee.

[b]Actual flue gas flowrate reported. Flue gas flowrate for the other plants was estimated assuming an excess air level of 80 percent and a flue gas temperature leaving the combustor of 450°F.

[c]Excludes reported costs of $600,000 for an ammonia slip continuous emission measurement system and ammonia safety equipment.

[d]NA = not available.

[e]Excludes the cost of an air compressor. The costs in parenthesis include the costs for an air compressor estimated using References 10 to 12.

TABLE 4-3. DIRECT AND INDIRECT CAPITAL COSTS DATA FOR THERMAL $DeNO_x$ [a]

Total Plant Capacity, tpd	Total Plant Flue Gas Flowrate, acfm [b]	Design NO_x Reduction, %	Direct Capital Costs, $1,000	Indirect Capital Costs $1,000 [c]	Indirect/ Direct Cost Ratio [d]
150	34,162	50	151 [e]	221	1.46
500	113,873	60	671 [f]	259	0.39
500	113,873	40	631	231	0.33
500	115,500	36	952 [g]	395 [h]	0.42
650	148,035	NA [i]	314	532	1.69
800	182,197	55	314 [e]	471	1.50
960	218,636	36	281	213	0.76
1,000	227,746	65	NA	NA	NA
1,200	273,295	NA	NA	NA	NA
1,440	332,970	36	1,550	459 [h]	0.30
1,500	341,619	50	704 [e]	359	0.51
3,000	683,239	NA	1,520	3,139	2.17

[a] Costs in December 1987 dollars.

[b] At 450°F.

[c] Excludes contingency costs.

[d] Ratio of indirect to direct capital costs.

[e] Costs used to develop scaling factor for direct capital cost equation in Table 4-1.

[f] Includes the cost of three 50 percent capacity air compressors. The other plants have one 100 percent air compressor.

[g] Excludes NH_3 slip CEM and ammonia safety equipment costs presented in Table 4-4.

[h] Excludes general and administrative expenses costs.

[i] NA = not available.

TABLE 4-4. CAPITAL COSTS FOR THERMAL $DeNO_x$ FOR TWO COMBUSTORS AT 250 TPD EACH (December 1987 dollars)[4,5]

	Exxon	Ogden Martin	Percent Difference[a]
1. Engineering Equipment Costs:			
o Ammonia injection header and nozzles	11,600	103,000	790
o Ammonia circulation heaters	4,050	7,700	90
o Air compressors	93,500	152,400	63
o Ammonia storage tank	21,900	24,100	10
o Ammonia safety equipment	N/A[b]	289,400	-
o Ammonia slip CEM	N/A	289,400	-
o Electrical equipment	N/A	31,000	-
o Instrumentation and controls	86,300	151,000	74
Total Engineering and Equipment (1)	217,400	1,048,000	250[c]
2. Direct Installation Costs:			
o Earthwork and concrete	N/A	67,000	-
o Structural steel and buildings	N/A	58,000	-
o Piping including valving and supports	124,100	173,000	39
o Electrical and controls	205,500	145,000	-30
o Equipment erection and painting	83,900	41,500	-51
Total Direct Installation Costs (2)	414,000	484,000	17
Total Direct Costs (3) = (1)+(2)	**631,400**	**1,532,000**	**97[b]**
3. Indirect Costs:			
o Construction management, indirects and fees	79,300	82,000	3
o Design engineering	70,500	217,000	210
o Exxon engineering	62,700	96,000	54
o General and administrative expenses	N/A	256,000	-
Total Indirect Costs (4)	213,000	651,000	206

Continued

TABLE 4-4 (CONCLUDED). CAPITAL COSTS FOR THERMAL $DeNO_x$ FOR TWO COMBUSTORS AT 250 TPD EACH (December 1987 dollars)

	Exxon	Ogden Martin	Percent Difference[a]
Exxon Licensing Fee (5)	96,000	92,600	-4
Contingency (6)	126,500	233,400	85
Total Capital Costs = (3)+ (4)+(5)+(6)	**1,067,000**	**2,510,000**	**135**

[a]Calculated as 100 * (Ogden Martin estimate - Exxon estimate)/Exxon estimate.

[b]N/A = not applicable.

[c]Excludes ammonia CEM costs.

design are based on site-specific requirements and are not expected to be required in most Thermal $DeNO_x$ systems. However, if these two items are excluded, the Exxon and Ogden Martin equipment costs are similar except for: (a) ammonia injection header and nozzles, (b) air compressors, and (c) instrumentation and controls. As shown in Table 4-5, costs for items (a) and (b) were compared to costs estimated from literature sources. Costs estimated from literature sources for these two areas are comparable with Exxon and are lower than those provided by Ogden Martin. For instrumentation and controls [item (c)], Exxon did not include automatic controls designed to meet continuous NO_x emission limits. As shown in Table 4-4, the direct installation costs as a percent of equipment costs are similar for both Exxon and Ogden Martin.

To account for the differences in equipment cost estimates between Exxon and Ogden Martin, the following two-step approach was used to derive the direct capital equation in Table 4-1. First, Exxon's direct capital costs presented in Table 4-4 were adjusted to include Ogden Martin's costs for instrumentation and controls, earthwork and concrete, and structural steel and buildings (Exxon costs did not include site preparation costs). A cost of $30,000 was also added to the direct capital cost for ammonia safety equipment consisting of water sprays and ambient ammonia monitoring. Instrumentation and control costs ($151,000) were assumed to be fixed; that is, they do not vary with combustor size.

Second, the direct capital costs of Thermal $DeNO_x$ excluding instrumentation and control costs were assumed to be related to the total plant flue gas flowrate by the following equation:

$$DC = a\,(T\_FLW)^{b} \qquad (1)$$

where:

DC = direct capital costs, 1,000$

T_FLW = total plant flue gas flowrate, acfm

a = coefficient

b = scaling factor

TABLE 4-5. COST ANALYSIS RESULTS USING DETAILED COSTS FROM EXXON AND OGDEN MARTIN

1. Cost Comparison with Literature for Engineering Equipment

	Literature	Exxon	Ogden Martin
Ammonia injection header and nozzles	20,200[a]	11,600	103,000
Air compressors	72,800[b]	93,500	152,400

2. Indirect Cost as Percentage of Direct Costs and Contingency Cost as a Percentage of the Direct and Indirect Costs

	Exxon	Ogden Martin[c]
Indirect costs	33	42
Contingency	15	17

[a]Extrapolated based on flue gas flowrate for a 500 MW coal-fired boiler equipped with SCR using 0.6 costing rule. Costs include only the NH_3/air mixer and injection grid of NH_3/air/flue gas. Cost data are from Reference 14.

[b]From Reference 15. Based on three 50 percent capacity industrial service air compressors (Ingersoll-Rand Type 40 series) rated at 50 psig. [Note: Exxon provided costs for air compressors based on three 50 percent capacity compressors. Ogden Martin did not indicate the basis for their air compressor costs].

[c]Excludes the costs for ammonia slip CEM, ammonia safety equipment, and general and administrative expenses.

Costs were adjusted to other plant sizes based on a scaling factor of 0.621. This scaling factor was estimated from the Exxon direct capital cost estimates in Table 4-3 for Thermal DeNO$_x$ systems designed for 50 to 55 percent NO$_x$ reduction. The other cost data in Table 4-3 were not used because of differences in design bases and costing procedures. The coefficient, a, in Equation 1 was determined from the adjusted costs from Step 1 above and the scaling factor.

Figure 4-1 presents the plot of the direct capital cost equation in Table 4-1 and the cost data from Table 4-3. As shown in the figure, the costs estimated by the equation are within the three cost data points for the 500 tpd (115,000 acfm) plant size. However, the costs estimated by the equation are higher than most of the other reported costs. As discussed above, the cost equation is based primarily on the itemized direct cost data provided by Exxon and Ogden Martin for a 500 tpd plant. Although no itemized cost data were provided for the other plants, it is believed that the lower costs for the other plants reflect system designs that did not include all of the needed equipment and installation expenses.

The cost equation in Table 4-1 is a based on flue gas flowrate instead of waste throughput (tpd). Although tpd of refuse is a rough estimate of flue gas flowrate, it does not differentiate between mass burn and RDF combustors or differences in design excess air levels. To accommodate short-term variations in feed waste composition and operating conditions, the flue gas flowrate used in the equation is based on 125 percent of the design flue gas flowrate.[16]

4.1.2 Indirect Costs

Indirect capital costs are typically a function of the direct capital costs. The indirect cost factor of 0.33 in Table 4-1 is based on the Exxon data from Table 4-5. This factor corresponds to the Exxon cost data for the 500 tpd plant. A startup cost of $10,000 for travel and supervision was added to the indirect costs since startup was not included in the indirect costs provided by Exxon.[17]

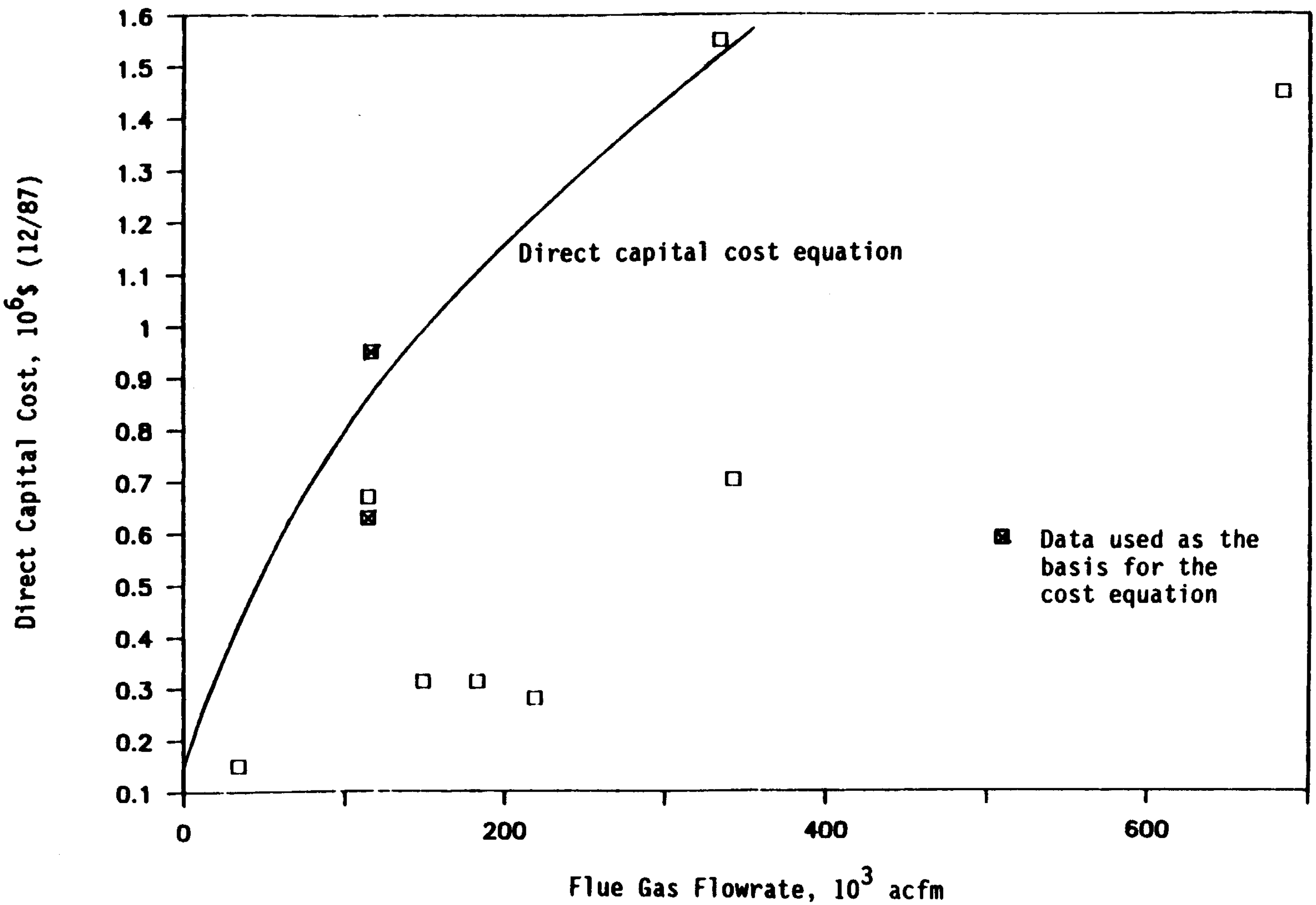

Figure 4-1. Comparison of the direct capital cost equation with the cost data.

4.1.3 Other Costs

A contingency based on 20 percent of the direct and indirect capital costs is included in the procedures. This contingency covers unforeseen expenses, the risks of failing to meet performance guarantees associated with Thermal $DeNO_x$, and operating experience of Thermal $DeNO_x$ applied to MWC's. This contingency level is the same used in the cost procedure for dry sorbent injection for acid gas control since both technologies are relatively new to MWC's.[18] This contingency level is slightly higher than estimated by Exxon and Ogden Martin in Table 4-5.

The licensing fee is estimated as a fixed cost plus an incremental cost based on capacity. The license fee equation in Table 4-1 is based on the data in Table 4-2 (corrected to December 1987 dollars). The reported versus estimated licensing are compared in Table 4-6. Preproduction costs are estimated from guidelines developed in Reference 19. Total capital costs for NO_x monitoring equipment is the incremental costs for NO_x of a combined $NO_x/SO_2/O_2$ monitor (in December 1987 dollars).[20]

4.2 OPERATING COST PROCEDURE

Table 4-7 presents the procedure for estimating annual operating costs for Thermal $DeNO_x$. The total annualized operating costs include labor-related costs (operating, supervision, maintenance, and overhead), electricity, ammonia consumption, operation and maintenance of the NO_x monitor, and additional capital-related charges such as taxes, insurance, administration, and capital recovery. Operating costs for Thermal $DeNO_x$ were obtained for the 12 mass burn/waterwall MWC facilities from data provided by Exxon and from other sources. The following four sections discuss the bases and rationale for the operating cost procedure.

4.2.1 Labor and Maintenance

Exxon indicated that Thermal DeNOx requires little additional maintenance and labor beyond that for the combustors. For this reason, operating and maintenance labor costs were estimated using the smallest labor requirement (0.5 hour/shift) prescribed by EPA/CEIS.[21] Supervision costs are 15 percent of the operating labor costs.[22] These labor estimates are consistent with those estimated by others.[23]

TABLE 4-6. COMPARISON OF ACTUAL AND PREDICTED LICENSE FEES[a]

Total Plant Capacity, tpd	Total Plant Flue Gas Flowrate, acfm[b]	Actual License Fee, $1,000	Predicted License Fee, $1,000[c]	Percent Error[d]
150	34,162	45	33	-27
500	113,873	96	103	7
500	113,873	96	103	7
500	115,500	93	105	11
650	148,035	165	133	-19
800	182,197	166	163	- 2
960	218,636	188	195	4
1,000	227,746	NA[e]	203	---
1,200	273,295	NA	243	---
1,440	332,970	323	237	-27
1,500	341,619	309	303	- 2
3,000	683,239	762	602	-21

[a]In December 1987 dollars.

[b]At 450°F.

[c]Costs estimated from equation presented in Table 4-1.

[d]Percent error = $\frac{\text{(Predicted-Actual) License Fee}}{\text{Actual License Fee}} \times 100$

[e]NA = not available.

TABLE 4-7. PROCEDURES FOR ESTIMATING ANNUAL OPERATING COSTS FOR THERMAL $DeNO_x$ APPLIED TO NEW MWC PLANTS[a,b]

Operating Labor (Basis: 0.5 man-hour/shift, wage of $12/hr):

OL = 0.75 * N * HRS

Supervision: 15% of the operating labor costs or 0.15 * OL

Maintenance Labor: (Basis: 0.5 man-hour/shift, 10% wage premium over the operating labor wage)

MAINT = 0.825 * N * HRS or 1.1 * OL

Maintenance Materials: 2 percent of the sum of the direct capital, indirect capital, and process contingency

Electricity: ELEC = (0.000391 * FLW + 0.963 * NH_3) * N * HRS * ERATE

Ammonia: AMM = NH_3 * HRS * ARATE/2,000

NO_x Monitoring: NO_xM = 19,000 * N

Overhead: 60% of all labor costs including maintenance materials

Taxes, Insurance, and Administrative Charges: 4% of the total capital cost excluding license fee and monitors

Capital Recovery (Basis: 15 year equipment life and 10% interest rate): 13.15% of the total capital investment

---

[a]All costs are in December 1987 dollars.

[b] OL = operating labor, $/yr
N = number of combustors
HRS = operating time at full rated capacity, hours/year
MAINT = maintenance costs, $/yr
ELEC = electricity costs, $/yr
FLW = flue gas flowrate per combustor at 450°F, acfm
NH_3 = ammonia injection rate, lb/hr
= $(0.015 + 0.0016 * NO_xR) * TPD * N * \frac{HHV}{4,595} * \frac{NO_x}{213}$

where: NO_xR = NO_x reduction, percent
TPD = combustor size, tpd
HHV = higher heating value for refuse, Btu/lb (defaults: 4,595 for MSW, 8,552 for RDF, and 5,080 for cofired RDF with wood)
NO_x = NO_x emissions without Thermal $DeNO_x$ control, ppmv at 7 percent O_2

ERATE = electrical power cost, $/kWh (default: $0.046/kWh)
AMM = ammonia costs, $/yr
ARATE = ammonia cost rate, $/ton (default: $200/ton)
NO_xM = NO_x monitoring operating and maintenance costs, $/yr

Maintenance materials are estimated at 2 percent of the total capital costs excluding both the monitor costs and license fee.[24] The maintenance cost estimates shown in Table 4-7 do not include any costs for increased maintenance of the boiler tubes from ammonia salt deposition that may be caused by Thermal $DeNO_x$. It is assumed that based on design and operation improvements gained from the initial Thermal $DeNO_x$ facilities, the potential of boiler tube fouling caused by ammonia salt deposition will be minimal. Consequently, cleaning of the boiler tubes can be performed during normally scheduled downtime periods. To be consistent with previous costing analysis for this source category, operating and maintenance labor wages are \$12/hr and \$13.20/hr (10 percent above \$12/hr), respectively.[25]

4.2.2 Electricity

The equation for estimating electricity costs (ELEC) is based on power consumption data provided by Exxon and others, as shown in Table 4-8.[26] Electricity is consumed primarily by the ammonia vaporizer and the air compressor. The electricity consumed by the ammonia vaporizer is directly related to ammonia injection rate, and the electricity consumed by the air compressor is proportional to the size of the combustor (i.e., flue gas flowrate). The electrical power requirements presented in Table 4-8 were linearly correlated with ammonia injection rate and flue gas flowrate, resulting in the following equation:

$$E_{POWER} = 0.000391 * FLW * N + 0.963 * NH_3 * N \qquad (2)$$

where:

E_{POWER} = electrical power requirement, kW

FLW = flue gas flowrate per combustor at 450°F, acfm

NH_3 = ammonia injection rate per combustor, lb/hr (see Equation 4)

N = number of combustors

Table 4-9 shows that, with the exception of the 150 tpd plant, Equation 1 is within ±40 percent of the data. Annual electricity cost (ELEC) is calculated

TABLE 4-8. ELECTRICAL POWER AND AMMONIA CONSUMED BY THERMAL DeNO$_x$ FOR SELECTED MWC PLANTS

Total Plant Capacity, tpd	Flue Gas Flowrate, acfm[a]	NH_3 Injection Rate, lb/hr (lb/ton MSW)	Electrical Power, kW	Design NO_x Reduction, %	References
150	34,162	25 (4.0)	38	50	3
500	113,873	55 (2.6)	155	60	3
500	113,873	NA[b] (NA)	NA	40	4
500	115,500	61 (2.9)	113	36	5
500	115,500	97 (4.7)	118	36	5
650	148,035	NA (NA)	NA	NA	6
960	218,636	71 (1.8)	110	36	3
1,000	227,746	110 (2.6)	171	65	7
1,200	273,295	218 (4.4)	353	NA	8
1,440	332,970	214 (3.6)	360	36	9
1,440	332,970	335 (5.6)	360	36	9
1,500	-	97 (1.6)	54[c]	50	3
3,000	683,239	354 (2.8)	NA	NA	6

[a] At 450°F.

[b] NA = not available.

[c] Power requirement for ammonia vaporization and heating only.

TABLE 4-9. COMPARISON OF ACTUAL AND PREDICTED ELECTRICAL POWER CONSUMED BY THERMAL $DeNO_x$ FOR SELECTED MWC PLANTS

Total Plant Capacity, tpd	Actual Electrical Power, kW	Predicted Electrical Power, kW[a]	Percent Error[b]
150	38	37	- 2
500	155	98	-37
500	113	104	- 8
500	118	139	17
960	110	154	40
1,000	171	195	14
1,200	353	317	-10
1,440	360	336	- 7
1,440	360	453	26
1,500	54	93	73

[a]Estimated using Equation 2.

[b]Percent error = $\frac{\text{(Predicted-Actual) Electrical Power}}{\text{Actual Electrical Power}} \times 100$

by multiplying the above power requirement rate equation by the annual operating hours and electricity price ($/kWh), as shown by the equation in Table 4-7. The default electrical price (ERATE) used in Table 4-7 is $0.046/kWh. This price was used in previous costing analyses for MWC's.[27]

4.2.3 Ammonia Consumption

The ammonia injection rate (NH_3) was determined based on operating and design parameters. The following equation (Equation 2) is derived for estimating ammonia consumption expressed in terms of lb NH_3/ton MSW using data reported in the compliance test for the Commerce MWC (presented in Section 3.4) and data reported by Exxon for NO_x reductions of 36 to 65 percent (see Table 4-8):[28]

$$NH_{3}\_T = [0.352 + 0.0385 * (NO_xR)] * \frac{NO_x}{213} * \frac{HHV}{4,595} \quad (3)$$

where
- NH_3_T = NH_3 injection rate, lb/ton MSW
- NO_xR = NO_x reduction, percent.
- NO_x = NO_x emissions without Thermal DeNO_x control, ppmv at 7 percent O_2.
- HHV = higher heating value of refuse, Btu/lb (this correction factor (HHV/4,595) can be used to convert lb NH_3/ton MSW to a lb NH_3/ton RDF or lb NH_3/ton cofired RDF using the respective heating values for RDF and cofired RDF.)

Figure 4-2 presents the plot of the above equation and the data obtained by Exxon and others.

From the data used to develop Equation 3, ammonia consumption ranges from 1.8 lb NH_3/ton MSW at 36 percent reduction to 2.6 lb NH_3/ton MSW at 65 percent NO_x reduction. Assuming an uncontrolled NO_x emission level of 213 ppm at 7 percent O_2, the NH_3-to-NO_x stoichiometric ratio ranges from 1.4 to 2.2. Two data points at 50 percent NO_x reduction reported by Exxon were excluded in developing Equation 2, because the reported ammonia injection rates at this NO_x reduction were inconsistent with each other and with the other data points. The large differences in ammonia consumption provided by Exxon for both data points at 50 percent reduction were attributed to the

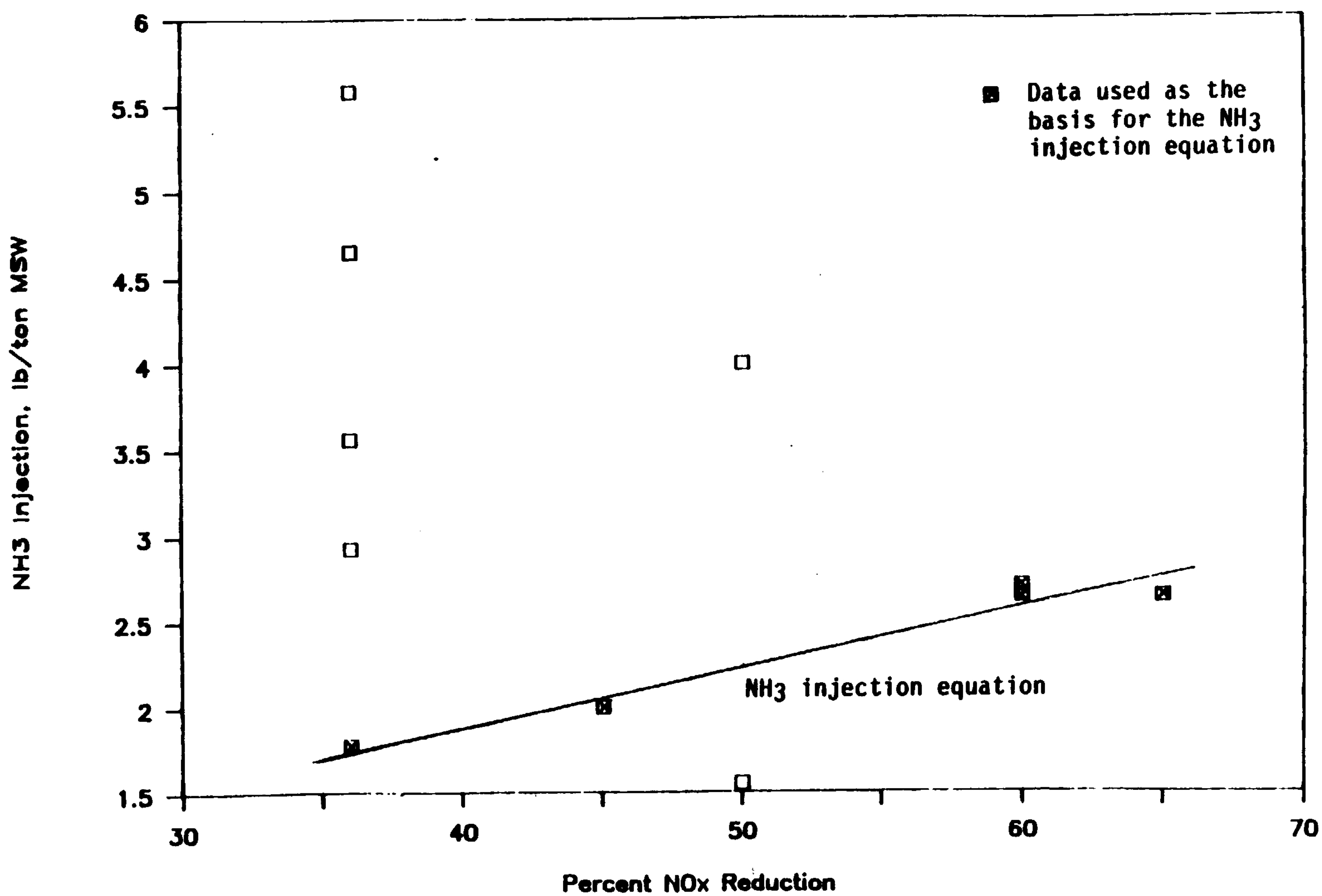

Figure 4-2. Comparison of the NH_3 injection equation with the contractor/vendor data.

differences in uncontrolled NO_x emissions used. By the same token, the ammonia consumption rates provided by Ogden Martin for achieving 36 percent NO_x removal for the 500 and 1,440 tpd plants were not considered, because the high ammonia injection rates may lead to high NH_3 slip. In addition, ammonia consumption rate did not agree with the ammonia injection rates measured at Commerce (2.0 lb NH_3/ton MSW at 45 percent NO_x reduction and 2.7 lb NH_3/ton MSW at 60 percent NO_x reduction).

Equation 3 is based on normalizing uncontrolled NO_x emissions to 213 ppmv at 7 percent O_2. Ammonia injection rate (NH_3), expressed in lb/hr, is calculated using Equation 4:

$$NH_3(\text{lb/hr}) = (0.015 + 0.0016 * NO_xR) * TPD * N * \frac{NO_x}{213} * \frac{HHV}{4{,}595} \quad (4)$$

where N = number of combustors

TPD = combustor size, tpd

HHV = higher heating value for the refuse, Btu/lb

Annual ammonia costs (AMM), as shown in Table 4-7, are calculated by multiplying Equation 3 by the annual hours of operation and the ammonia price in dollars per ton. Based on contacts with ammonia producers and readily available information, ammonia costs per ton across the country vary between \$90 and \$230/ton.[29-31]

4.2.4 Other Costs

Operating and maintenance costs for the NOx monitoring equipment are the incremental costs for NO_x of a combined $NO_x/SO_2/O_2$ monitor (in December 1987 dollars).[32] Overhead and capital charges such as taxes, insurance, administration, and capital recovery are estimated using the same procedure used in previous costing analyses.[33] Downtime costs are not included in the annual operating costs. It is assumed that the operating experience of this technology gained from now to the time of the NSPS proposal (November 1989) will result in little or no downtime costs.

4.3 REFERENCES

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5.0 MODEL PLANT COSTS FOR THERMAL DENO$_x$

This section presents the costs of Thermal DeNO$_x$ for the 12 111(b) model plants. Table 5-1 presents key design information for the 111(b) model plants. Table 5-2 presents plant specifications and flue gas composition data for each model plant. Reference 1 describes the rationale in selecting these model plants and presents combustor capital and operating costs (without Thermal DeNO$_x$) for each model plant. Procedures presented in Section 4.0 of this report were used to estimate the capital and operating costs of Thermal DeNO$_x$ for the 12 model plants. As presented in Section 3.4, Thermal DeNO$_x$ has been demonstrated to achieve 45 percent NO$_x$ reduction. Therefore, Thermal DeNO$_x$ costs are based on this NO$_x$ reduction efficiency. Sections 5.1, 5.2, 5.3, 5.4, 5.5, and 5.6 present the Thermal DeNO$_x$ costs for the mass burn/waterwall, mass burn/refractory, mass burn/rotary, refuse-derived fuel (RDF), modular combustor, and the fluidized-bed combustor (FBC) model plants, respectively. Also presented in each section are the annual NO$_x$ emission reductions (tons/year and Mg/year), cost effectiveness ($/ton and $/Mg), and annual electrical consumption (MWh/year) for Thermal DeNO$_x$ for each model plant. Section 5.7 summarizes Thermal DeNO$_x$ costs, cost effectiveness, and electrical requirements for each model plant.

Section 5.8 presents the results of the cost sensitivity analysis for Thermal DeNO$_x$ as a function of ammonia and electrical prices across the U.S. This section also estimates the costs of Thermal DeNO$_x$ for achieving 65 percent NO$_x$ emission reduction. The analysis was performed using the 800 tpd mass burn/waterwall model plant and the 2,000 tpd RDF model plant.

5.1 MASS BURN/WATERWALL

Table 5-3 presents the capital costs for the 200, 800, and 2,250 tpd mass burn/waterwall model plants. This table shows the combustor capital costs as well as the itemized costs for Thermal DeNO$_x$. Thermal DeNO$_x$ capital costs range from $1,010,000 for the 200 tpd plant to $3,740,000 for the 2,250 tpd plant. The increase in total plant capital costs due to Thermal DeNO$_x$ ranges from 3.4 percent for the 2,250 tpd plant to 5.7 percent for the 200 tpd plant.

TABLE 5-1. MODEL PLANT SELECTION FOR 111(b)

Model Plant Number	Combustor type	Unit size, (tpd)	Number of combustors	Total plant capacity, (tpd)	Annual operating hours[a]	Heat recovery	Fuel
1	Mass burn/waterwall	100	2	200	5,000	Steam	100% MSW
2	Mass burn/waterwall	400	2	800	8,000	Electricity	100% MSW
3	Mass burn/waterwall	750	3	2,250	8,000	Electricity	100% MSW
4	Mass burn/refractory	250	2	500	8,000	Electricity	100% MSW
5	Mass burn/rotary combustor (waterwall)	350	3	1,050	8,000	Electricity	100% MSW
6	Refuse-derived fuel	500[b]	4	2,000	8,000	Electricity	100% RDF
7	Refuse-derived fuel	500[b]	4	2,000	8,000	Electricity	50% RDF/ 50% wood
8	Modular excess air	120	2	240	8,000	Electricity	100% MSW
9	Modular/starved air	25	2	50	5,000	None	100% MSW
10	Modular/starved air	50	2	100	8,000	Electricity	100% MSW
11	Fluidized-bed combustion (BFB)[c]	450	2	900	8,000	Electricity	100% RDF
12	Fluidized-bed combustion (CFB)[c]	450	2	900	8,000	Electricity	100% RDF

[a]24 hr/day x 333 days/yr = 8,000 hr/yr
100 hr/wk x 50 wk/yr = 5,000 hr/yr

[b]Unit size represents RDF for Model Number 6 and represents combined RDF and wood for Model Number 7.

[c]BFB = Bubbling Fluidized-bed; and CFB = Circulating fluidized-bed

TABLE 5-2. MODEL PLANT SPECIFICATIONS AND FLUE GAS COMPOSITION DATA

Item	Model Plants[a]											
	Small MB/WW (No. 1)	Medium MB/WW (No. 2)	Large MB/WW (No. 3)	MB/REF (No. 4)	MB/RC (No. 5)	RDF (No. 6)	RDF (Cofired) (No. 7)	MI/EA (No. 8)	MI/SA (No Heat Rec.) (No. 9)	MI/SA (No. 10)	FBC (No. 11)	FBC (No. 12)
Facility Specification												
No. of combustors per model	2	2	3	2	3	4	4	2	2	2	2	2
Total daily charge rate, tpd	200	800	2,250	500	1,050	2,000	2,000	240	50	100	900	900
Annual operating hours	5,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	5,000	8,000	8,000	8,000
Ash content of feed waste, %[b]	22.2	22.2	22.2	22.2	22.2	7.5	4.3	22.2	22.2	22.2	7.5	7.5
Excess combustion air, % of theoretical	80	80	80	200	50	50	50	100	100	100	60	60
PM emission factor, % of feed waste ash[b]	10	10	10	10	10	80	80	0.50	0.50	0.50	80	80
Baseline PM emission rate, gr/dscf:	0.08	0.05	0.05	0.08	0.05	0.05	0.05	0.08	0.1	0.08	0.01	0.01
Stack height, ft	140	200	230	150	125	200	200	70	60	60		
Stack diameter, ft	4.0	6.0	7.0	9.0	5.0	8.0	8.0	6.0	5.0	5.0		
Number of stacks	2	2	3	2	3	4	4	1	1	1	2	2
Flue Gas Data Per Combustor[c]												
Volume flowrate:												
dscfm	11,500	46,000	86,200	48,100	33,400	58,700	52,000	15,300	3,200	6,400	56,400	56,400
scfm	13,300	53,100	99,500	52,500	39,600	68,500	62,600	17,500	3,600	7,300	65,200	65,200
acfm	22,800	91,100	171,000	90,200	68,100	118,000	107,000	30,000	14,100	12,500	99,700	99,700
Outlet temperature °F	450	450	450	450	450	450	450	450	1,600	450	350	350

Continued

TABLE 5-2 (CONCLUDED). MODEL PLANT SPECIFICATIONS AND FLUE GAS COMPOSITION DATA

Item	Model Plants[a]											
	Small MB/WW (No. 1)	Medium MB/WW (No. 2)	Large MB/WW (No. 3)	MB/REF (No. 4)	MB/RC (No. 5)	RDF (No. 6)	RDF (Cofired) (No. 7)	MI/EA (No. 8)	MI/SA (No Heat Rec.) (No. 9)	MI/SA (No. 10)	FBC (No. 11)	FBC (No. 12)
Emission concentrations per combustor at 7% O_2 (dry)[d]:												
NO_x, ppmv	213	213	213	213	213	213	213	213	213	213	200	200
Particulate Matter:												
mg/dscm	4,600	4,600	4,600	4,600	4,600	9,200	9,200	4,600	230	230	23	23
(gr/dscf)	(2)	(2)	(2)	(2)	(2)	(4)	(4)	(2)	(0.1)	(0.1)	(0.01)	(0.01)
CO, ppmv	50	50	50	100	100	100	100	100	50	50	50	100
CDD/CDF, ng/dscm	200	200	200	300	300	200	200	200	300	300	20	400
Acid gas:												
HCl, ppmv	500	500	500	500	500	500	250	500	500	500	350	350
SO_2, ppmv	200	200	200	200	200	300	150	200	200	200	240	240
Annual Emissions per combustor at 7% O_2 (dry):[d]												
NO_x, tons/yr	72	463	1,300	290	607	1,420	1,260	139	18	58	301	301
PM, tons/yr	408	2,610	4,890	1,630	2,280	8,030	7,130	783	5	16	16.4	16.4
CO, tons/yr	5	33	62	41	58	102	90	22	2	4	20.8	42.0
CDD/CDF ($x 10^{-2}$), lbs/yr	3.56	22.8	42.8	21.4	29.8	35.2	31.1	6.84	1.34	4.28	3.16	63.3
HCl, tons/yr	69	439	823	274	383	669	326	132	17	55	457	457
SO_2, tons/yr	50	320	601	200	280	666	368	96	13	40	379	379

[a] MB/WW - mass burn/waterwall, MB/REF - mass burn/refractory, MB/RC - mass burn/rotary combustor, MI/EA - modular/excess air, MI/SA - modular/starved air, RDF - refuse-derived fuel, and FBC - fluidized-bed combustion.
[b] From Report to Congress, Publication No. EPA/530-SW-87-021e.
[c] Calculated based on the facility specifications in this table and the feed waste composition data from Table 1-3 in Reference 1.
[d] Emissions at combustor exit. Annual emissions from the stack except for NO_x are included in Section 7.0 in Reference 1. At baseline, excluding Model Plant No. 9, stack emissions of PM are assumed to comply with the 0.05 gr/dscf or 0.08 gr/dscf limits as required by 40 CFR 60, Subparts Db or E. (Model Plant 9 is smaller than the 50 tpd combustor size cutoff in Subpart E.) Baseline controls would not affect emissions of the other pollutants listed, and stack emissions would be the same as listed above. Annual emissions for NO_x can be estimated from data in this section.

TABLE 5-3. CAPITAL COSTS FOR THE MASS BURN/WATERWALL MODEL PLANTS - NO. 1 TO 3 ($1,000's in December 1987)

	No. 1 200 tpd Plant	No. 2 800 tpd Plant	No. 3 2,250 tpd Plant
Total Combustor Capital Cost	17,860	50,000	110,000
Thermal $DeNO_x$ Capital Cost			
Direct Cost	550	1,090	1,940
Indirect Cost	191	371	651
Process Contingency Cost	148	293	519
Licensing Fee	43	163	452
Preproduction	25	50	98
NO_x Monitoring Equipment	48	48	72
Total Thermal $DeNO_x$ Cost	1,010	2,020	3,740
Total Plant Capital Cost	18,870	52,020	113,740
Percent Cost Increase Attributed to Thermal $DeNO_x$	5.7	4.0	3.4

Table 5-4 presents the annualized costs for the 200, 800, and 2,250 tpd mass burn/waterwall model plants. This table shows the combustion annualized costs as well as the itemized Thermal $DeNO_x$ annualized costs at 45 percent NO_x reduction. Annualized costs for Thermal $DeNO_x$ range from $279,000 for the 200 tpd plant to $1,140,000 for the 2,250 tpd plant. The increase in total plant annualized costs attributed to Thermal $DeNO_x$ ranges from 3.7 percent for the 2,250 tpd plant to 5.8 percent for the 200 tpd plant. Cost effectiveness compared to uncontrolled range from $2,150/Mg ($1,950/ton) for the 2,250 tpd plant to $9,450/Mg ($8,570/ton) for the 200 tpd plant.

Table 5-4 also presents estimates of annual electrical requirements and NO_x emission reductions for Thermal $DeNO_x$ at each model plant. The electrical requirements range from 173 MWh/yr for the 200 tpd plant to 3,110 MWh/yr for the 2,250 tpd plant. Emission reductions of NO_x corresponding to 45 percent NO_x reduction range from 30 Mg/yr (33 tons/yr) for the 200 tpd plant to 531 Mg/yr (586 tons/yr) for the 2,250 tpd plant. The annualized costs, electrical requirements, and NO_x emission reductions are based on 5,000 hours of operation for the 200 tpd plant and 8,000 hours of operation for the 800 and 2,250 tpd plants.

5.2 MASS BURN/REFRACTORY

Table 5-5 presents the capital costs for the 500 tpd mass burn/refractory model plant. This table shows the combustor capital costs as well as the itemized costs for Thermal $DeNO_x$. Thermal $DeNO_x$ capital costs are $2,010,000 for this plant. The increase in plant capital costs attributed to Thermal $DeNO_x$ is 5.4 percent.

Table 5-6 presents the annualized costs for the 500 tpd mass burn/refractory model plant. This table shows the combustor annualized costs as well as the itemized Thermal $DeNO_x$ annualized costs at 45 percent NO_x reduction. Annualized costs for Thermal $DeNO_x$ are $549,000. The increase in total plant annualized costs attributed to Thermal $DeNO_x$ is 4.6 percent. Cost effectiveness of removing NO_x is $4,640/Mg ($4,210/ton).

Table 5-6 also presents estimates of annual electrical requirements and NO_x emission reductions for Thermal $DeNO_x$ at this plant. The electrical requirement for this plant is 899 MWh/yr. Emission reduction of NO_x is

TABLE 5-4. ANNUALIZED COSTS, ECONOMIC AND ENVIRONMENTAL IMPACTS FOR THE MASS BURN/WATERWALL MODEL PLANTS - NO. 1 TO 3 ($1,000's in December 1987)

	No. 1 200 tpd Plant	No. 2 800 tpd Plant	No. 3 2,250 tpd Plant
Combustor Annualized Cost	4,850	14,370	31,000
Thermal $DeNO_x$ Cost			
Direct Cost:			
- Operating Labor	8	12	18
- Supervision	1	2	3
- Maintenance	26	48	82
- Electricity	8	51	143
- Ammonia	9	56	156
- NO_x Monitoring Equipment	38	38	57
Total Direct Cost	89	207	459
Indirect Cost:			
- Overhead	21	37	62
- Taxes, Insurance, and Administration	37	72	128
- Capital Recovery	132	265	491
Total Indirect Cost	190	374	681
Total Annualized Cost	279	582	1,140
Total Plant Annualized Cost	5,130	14,950	32,140
Percent Cost Increase Attributed to Thermal $DeNO_x$	5.8	4.1	3.7
NO_x Reduction, tons/yr (Mg/yr)	33(30)	208(189)	586(531)
Cost Effectiveness, $/ton ($/Mg)	8,570 (9,450)	2,790 (3,080)	1,950 (2,150)
Electricity Use of Thermal $DeNO_x$, MWh/yr	173	1,110	3,110

TABLE 5-5. CAPITAL COSTS FOR THE MASS BURN/REFRACTORY MODEL PLANT - NO. 4
($1,000's in December 1987)

	500 tpd Plant
<u>Total Combustor Capital Cost</u>	37,550
<u>Thermal DeNO$_x$ Capital Cost</u>	
Direct Cost	1,090
Indirect Cost	369
Process Contingency Cost	291
Licensing Fee	161
Preproduction	47
NO$_x$ Monitoring Equipment	48
Total Thermal DeNO$_x$ Cost	2,010
<u>Total Plant Capital Cost</u>	39,560
Percent Cost Increase Attributed to Thermal DeNO$_x$	5.4

TABLE 5-6. ANNUALIZED COSTS, ECONOMIC AND ENVIRONMENTAL IMPACTS FOR THE MASS BURN/REFRACTORY MODEL PLANT - NO. 4 ($1,000's in December 1987)

	500 tpd Plant
Combustor Annualized Cost	11,870
Thermal $DeNO_x$ Cost	
Direct Cost:	
- Operating Labor	12
- Supervision	2
- Maintenance	48
- Electricity	41
- Ammonia	35
- NO_x Monitoring Equipment	38
Total Direct Cost	176
Indirect Cost:	
- Overhead	37
- Taxes, Insurance, and Administration	72
- Capital Recovery	264
Total Indirect Cost	373
Total Annualized Cost	549
Total Plant Annualized Cost	12,420
Percent Cost Increase Attributed to Thermal $DeNO_x$	4.6
NO_x Reduction, tons/yr (Mg/yr)	130(118)
Cost Effectiveness, $/ton ($/Mg)	4,210 (4,640)
Electricity Use of Thermal $DeNO_x$, MWh/yr	899

118 Mg/yr (130 tons/yr). The annualized costs, electrical requirement, and NO_x emission reduction are based on 8,000 hours of operation.

5.3 MASS BURN/ROTARY COMBUSTOR

Table 5-7 presents the capital costs for the 1,050 tpd mass burn/rotary combustor model plant. This table shows the combustor capital costs as well as the itemized costs for Thermal $DeNO_x$. Thermal $DeNO_x$ capital costs are $2,180,000 for this plant. The increase in plant capital costs attributed to Thermal $DeNO_x$ is 3.2 percent.

Table 5-8 presents the annualized costs for the 1,050 tpd mass burn/rotary combustor model plant. This table shows the combustor annualized costs as well as the itemized Thermal $DeNO_x$ annualized costs at 45 percent NO_x reduction. Annualized costs for Thermal $DeNO_x$ are $680,000 for this plant. The increase in total plant annualized costs attributed to Thermal $DeNO_x$ is 3.5 percent. Cost effectiveness of removing NO_x is $2,740/Mg ($2,490/ton).

Table 5-8 also presents estimates of annual electrical requirements and NO_x emission reductions for Thermal $DeNO_x$ at this plant. Electrical requirement for this plant is 1,340 MWh/yr. Emission reduction of NO_x is 248 Mg/yr (273 tons/yr). The annualized costs, electrical requirement, and NO_x emission reduction are based on 8,000 hours of operation.

5.4 REFUSE-DERIVED FUEL

Table 5-9 presents the capital costs for the 2,000 tpd RDF and the 2,000 tpd cofired RDF/wood model plants. This table shows the combustor capital costs as well as the itemized costs for Thermal $DeNO_x$. Thermal $DeNO_x$ capital costs are $3,570,000 for the 2,000 tpd RDF plant and $3,380,000 for the 2,000 tpd cofired RDF plant. The capital costs for Thermal $DeNO_x$ increase the total plant capital costs by 2.6 percent for the 2,000 tpd RDF plant and 2.4 percent for the 2,000 tpd cofired RDF plant.

Table 5-10 presents the annualized costs for the 2,000 tpd RDF and cofired RDF plants. This table shows the combustor annualized costs as well as the itemized Thermal $DeNO_x$ annualized costs at 45 percent NO_x reduction.

TABLE 5-7. CAPITAL COSTS FOR THE MASS BURN/ROTARY COMBUSTOR MODEL PLANT - NO. 5 ($1,000's in December 1987)

	1,050 tpd Plant
Total Combustor Capital Cost	69,140
Thermal $DeNO_x$ Capital Cost	
Direct Cost	1,160
Indirect Cost	394
Process Contingency Cost	311
Licensing Fee	182
Preproduction	56
NO_x Monitoring Equipment	72
Total Thermal $DeNO_x$ Cost	2,180
Total Plant Capital Cost	71,320
Percent Cost Increase Attributed to Thermal $DeNO_x$	3.2

TABLE 5-8. ANNUALIZED COSTS, ECONOMIC AND ENVIRONMENTAL IMPACTS FOR THE MASS BURN/ROTARY COMBUSTOR MODEL PLANT - NO. 5 ($1,000's in December 1987)

	1,050 tpd Plant
Combustor Annualized Cost	19,520
Thermal $DeNO_x$ Cost	
Direct Cost:	
- Operating Labor	18
- Supervision	3
- Maintenance	57
- Electricity	62
- Ammonia	73
- NO_x Monitoring Equipment	57
Total Direct Cost	270
Indirect Cost:	
- Overhead	47
- Taxes, Insurance, and Administration	77
- Capital Recovery	286
Total Indirect Cost	410
Total Annualized Cost	680
Total Plant Annualized Cost	20,200
Percent Cost Increase Attributed to Thermal $DeNO_x$	3.5
NO_x Reduction, tons/yr (Mg/yr)	273(248)
Cost Effectiveness, $/ton ($/Mg)	2,490 (2,740)
Electricity Use of Thermal $DeNO_x$, MWh/yr	1,340

TABLE 5-9. CAPITAL COSTS FOR THE REFUSE-DERIVED FUEL FIRED MODEL PLANTS - NO. 6 AND 7 ($1,000's in December 1987)

	No. 6 2,000 tpd Plant	No. 7 2,000 tpd Cofired Plant
Total Combustor Capital Cost	135,000	143,800
Thermal $DeNO_x$ Capital Cost		
Direct Cost	1,850	1,760
Indirect Cost	620	590
Process Contingency Cost	494	469
Licensing Fee	415	380
Preproduction	97	92
NO_x Monitoring Equipment	96	96
Total Thermal $DeNO_x$ Cost	3,570	3,380
Total Plant Capital Cost	138,570	147,180
Percent Cost Increase Attributed to Thermal $DeNO_x$	2.6	2.4

TABLE 5-10. ANNUALIZED COSTS, ECONOMIC AND ENVIRONMENTAL IMPACTS FOR THE REFUSE-DERIVED FUEL FIRED MODEL PLANTS - NO. 6 AND 7 ($1,000's in December 1987)

	No. 6 2,000 tpd Plant	No. 7 2,000 tpd Cofired Plant
Combustor Annualized Cost	33,200	35,070
Thermal $DeNO_x$ Cost		
Direct Cost:		
- Operating Labor	24	24
- Supervision	4	4
- Maintenance	85	82
- Electricity	142	130
- Ammonia	168	154
- NO_x Monitoring Equipment	76	76
Total Direct Cost	499	470
Indirect Cost:		
- Overhead	68	66
- Taxes, Insurance, and Administration	122	116
- Capital Recovery	470	445
Total Indirect Cost	660	627
Total Annualized Cost	1,160	1,100
Total Plant Annualized Cost	34,360	36,170
Percent Cost Increase Attributed to Thermal $DeNO_x$	3.5	3.1
NO_x Reduction, tons/yr (Mg/yr)	641(582)	569(516)
Cost Effectiveness, $/ton ($/Mg)	1,810 (1,990)	1,930 (2,130)
Electricity Use of Thermal $DeNO_x$, MWh/yr	3,090	2,820

Annualized costs for Thermal $DeNO_x$ are $1,160,000 for the 2,000 tpd RDF plant and $1,100,000 for the 2,000 tpd cofired RDF plant. The respective increases in total plant annualized costs attributed to Thermal $DeNO_x$ are 3.5 and 3.1 percent. Cost effectiveness is $1,990/Mg ($1,810/ton) for the 2,000 tpd RDF plant and $2,130/Mg ($1,930/ton) for the 2,000 tpd cofired RDF plant.

Table 5-10 also presents estimates of annual electrical requirements and NO_x emission reductions for Thermal $DeNO_x$ at each model plant. The electrical requirements are 3,090 and 2,820 MWh/yr for the 2,000 tpd RDF and 2,000 tpd cofired RDF plants, respectively. Emission reductions of NO_x are 582 Mg/yr (641 tons/yr) for the 2,000 tpd RDF plant and 516 Mg/yr (569 tons/yr) for the 2,000 tpd cofired RDF plant. Uncontrolled NO_x emissions in terms of ppm at 7 percent O_2 are about the same for RDF and wood/RDF firing, since NO_x emissions from wood firing alone are about the same as MWC firing. The annualized cost, electrical requirements, and NO_x emission reductions are based on 8,000 hours of operation for both plants.

5.5 MODULAR COMBUSTORS

Table 5-11 presents the capital costs for the 240 tpd modular excess air, the 50 tpd modular starved air, and the 100 tpd modular starved air model plants. This table shows the combustor capital costs as well as the itemized costs for Thermal $DeNO_x$. Thermal $DeNO_x$ capital costs range from $616,000 for the 50 tpd modular starved air plant to $1,140,000 for the 240 tpd modular excess air plant. The increase in total plant capital costs due to Thermal $DeNO_x$ ranges from 8.7 percent for the 240 tpd plant to 49 percent for the 50 tpd plant.

Table 5-12 presents the annualized costs for the three modular plants. This table shows the combustor annualized costs as well as the itemized Thermal $DeNO_x$ annualized costs at 45 percent NO_x reduction. Annualized costs for Thermal $DeNO_x$ range from $190,000 for the 50 tpd plant to $337,000 for the 240 tpd plant. The increases in total plant annualized costs attributed to Thermal $DeNO_x$ range from 7.7 percent for the 240 tpd plant to 31 percent for the 50 tpd plant. Cost effectiveness range from $5,950/Mg ($5,400/ton) for the 240 tpd plant to $25,700/Mg ($23,300/ton) for the 50 tpd plant.

TABLE 5-11. CAPITAL COSTS FOR THE MODULAR MODEL PLANTS - NO. 8 TO 10
($1,000's in December 1987)

	No. 8 240 tpd Excess Air	No. 9 50 tpd Starved Air	No. 10 100 tpd Starved Air
Total Combustor Capital Cost	13,150	1,270	5,510
Thermal $DeNO_x$ Capital Cost			
Direct Cost	624	330	426
Indirect Cost	216	119	150
Process Contingency Cost	168	90	115
Licensing Fee	56	14	25
Preproduction	27	15	19
NO_x Monitoring Equipment	48	48	48
Total Thermal $DeNO_x$ Cost	1,140	616	783
Total Plant Capital Cost	14,290	1,890	6,290
Percent Cost Increase Attributed to Thermal $DeNO_x$	8.7	48.5	14.2

TABLE 5-12. ANNUALIZED COSTS, ECONOMIC AND ENVIRONMENTAL IMPACTS FOR THE MODULAR MODEL PLANTS - NO. 8 TO 10 ($1,000's in December 1987)

	No. 8 240 tpd Excess Air	No. 9 50 tpd Starved Air	No. 10 100 tpd Starved Air
Combustor Annualized Cost	4,360	605	1,830
Thermal $DeNO_x$ Cost			
Direct Cost:			
- Operating Labor	12	8	12
- Supervision	2	1	2
- Maintenance	33	19	27
- Electricity	16	2	7
- Ammonia	17	2	7
- NO_x Monitoring Equipment	38	38	38
Total Direct Cost	118	70	92
Indirect Cost:			
- Overhead	28	17	24
- Taxes, Insurance, and Administration	41	22	28
- Capital Recovery	150	81	103
Total Indirect Cost	219	120	155
Total Annualized Cost	337	190	248
Total Plant Annualized Cost	4,700	795	2,080
Percent Cost Increase Attributed to Thermal $DeNO_x$	7.7	31.4	13.6
NO_x Reduction, tons/yr (Mg/yr)	63(57)	8.2(7.4)	26(24)
Cost Effectiveness, $/ton ($/Mg)	5,400 (5,950)	23,300 (25,700)	9,530 (10,500)
Electricity Use of Thermal $DeNO_x$, MWh/yr	348	45	145

Table 5-12 also presents estimates of annual electrical requirements and NO_x emission reductions for Thermal $DeNO_x$ at each model plant. The electrical requirements range from 45 MWh/yr for the 50 tpd plant to 348 MWh/yr for the 240 tpd plant. Emission reductions of NO_x ranged from 7 Mg/yr (8 tons/yr) for the 50 tpd plant to 57 Mg/yr (63 tons/yr) for the 240 tpd plant. The annualized costs, electrical requirements, and NO_x emission reductions are based on 5,000 hours of operation for the 50 tpd modular starved air plant and 8,000 hours of operation for the other two plants.

5.6 FLUIDIZED-BED COMBUSTION

Table 5-13 presents the capital costs for the 900 tpd bubbling bed and the 900 tpd circulating bed model plants. This table shows the combustor capital costs as well as the itemized costs for thermal $deNO_x$. Thermal $DeNO_x$ capital costs are $2,270,000 for each model plant. The increase or total plant capital costs due to thermal $deNO_x$ is 3.1 percent.

Table 5-14 presents the annualized costs for both plants. This table shows the combustor annualized costs as well as the itemized thermal $deNO_x$ annualized costs at 45 percent NO_x reduction. Annualized costs for thermal $deNO_x$ is $658,000 for each plant. The increase in total plant annualized costs attributed to thermal $deNO_x$ is 3.4 percent. Cost effectiveness is $2,670/Mg ($2,430/ton) for each plant.

Table 5-14 also presents estimates of annual electrical requirements and NO_x emission reductions for thermal $deNO_x$ at each plant. The electrical requirement is 1,380 MWh/yr for each plant. Emission reduction of NO_x is 246 Mg/yr (271 tons/yr). The annualized costs, electrical requirements, and NO_x emission reductions are based on 8,000 hours of operation for both plants.

5.7 SUMMARY OF NO_x EMISSION REDUCTION, COST EFFECTIVENESS, AND ELECTRICAL REQUIREMENTS

Table 5-15 summarizes the information on NO_x emission reductions, capital costs, annualized costs, cost effectiveness, and electrical requirements for the 12 model plants. Also shown are annual tonnages of waste combusted by each model plant.

TABLE 5-13. CAPITAL COSTS FOR THE FLUIDIZED BED COMBUSTION MODEL PLANTS - NO. 11 AND 12 ($1,000's in December 1987)

	No. 11 900 tpd Bubbling Bed Plant	No. 12 900 tpd Circulating Bed Plant
Total Combustor Capital Cost	73,870	73,870
Thermal $DeNO_x$ Capital Cost		
Direct Cost	1,220	1,220
Indirect Cost	413	413
Process Contingency Cost	327	327
Licensing Fee	199	199
Preproduction	57	57
NO_x Monitoring Equipment	48	48
Total Thermal $DeNO_x$ Cost	2,270	2,270
Total Plant Capital Cost	76,140	76,140
Percent Cost Increase Attributed to Thermal $DeNO_x$	3.1	3.1

TABLE 5-14. ANNUALIZED COSTS, ECONOMIC AND ENVIRONMENTAL IMPACTS FOR THE FLUIDIZED BED COMBUSTION MODEL PLANTS - NO. 11 AND 12 ($1,000's in December 1987)

	No. 11 900 tpd Bubbling Bed Plant	No. 12 900 tpd Circulating Bed Plant
Combustor Annualized Cost	19,300	19,300
Thermal $DeNO_x$ Cost		
Direct Cost:		
- Operating Labor	12	12
- Supervision	2	2
- Maintenance	52	52
- Electricity	64	64
- Ammonia	71	71
- NO_x Monitoring Equipment	38	38
Total Direct Cost	239	239
Indirect Cost:		
- Overhead	40	40
- Taxes, Insurance, and Administration	81	81
- Capital Recovery	298	298
Total Indirect Cost	419	419
Total Annualized Cost	658	658
Total Plant Annualized Cost	19,960	19,960
Percent Cost Increase Attributed to Thermal $DeNO_x$	3.4	3.4
NO_x Reduction, tons/yr (Mg/yr)	271(246)	271(246)
Cost Effectiveness, $/ton ($/Mg)	2,430 (2,670)	2,430 (2,670)
Electricity Use of Thermal $DeNO_x$, MWh/yr	1,380	1,380

TABLE 5-15. SUMMARY OF COSTS, COST EFFECTIVENESS, AND ELECTRICAL REQUIREMENTS FOR NEW MWC MODEL PLANTS USING THERMAL $DeNO_x$

Model Plant No.	Model Plant Type[a]	Model Plant TPY[b]	NO_x Emission Reduction tons/yr (Mg/yr)	Thermal $DeNO_x$ Capital Costs, $1,000	Thermal $DeNO_x$ Annualized Costs, $1,000	Cost Effectiveness $/ton ($/Mg)	Annual Electrical Requirements, MWh/yr
1	MB/WW	41,700	33 (30)	1,010	279	8,570 (9,450)	173
2	MB/WW	267,000	208 (189)	2,020	582	2,790 (3,080)	1,110
3	MB/WW	750,000	586 (531)	3,740	1,140	1,950 (2,150)	3,110
4	MB/REF	167,000	130 (118)	2,010	549	4,210 (4,640)	899
5	MB/RC	350,000	273 (248)	2,180	680	2,490 (2,740)	1,340
6	RDF	667,000	641 (582)	3,570	1,160	1,810 (1,990)	3,090
7	RDF (Cofired)	667,000	569 (516)	3,380	1,100	1,930 (2,130)	2,820
8	MI/EA	80,000	63 (57)	1,140	337	5,400 (5,950)	348
9	MI/SA	10,400	8.2 (7.4)	616	190	23,300 (25,700)	45
10	MI/SA	20,800	26 (24)	783	248	9,530 (10,500)	145
11	FBC	300,000	271 (246)	2,270	658	2,430 (2,670)	1,380
12	FBC	300,000	271 (246)	2,270	658	2,430 (2,670)	1,380

[a]MB/WW = mass burn/waterwall
MB/REF = mass burn/refractory
MB/RC = mass burn/rotary combustor
RDF = refuse-derived fuel
MI/EA = modular incinerator/excess air
MI/SA = modular incinerator/starved air

[b]TPY = tons per year of refuse

5.8 COST SENSITIVITY ANALYSIS

This section presents the variations in costs and cost effectiveness of Thermal $DeNO_x$ with changes in ammonia and electrical power costs. Costs of anhydrous ammonia ($/ton) and electrical power ($/kWh) can vary widely across the country. A survey of anhydrous ammonia and electrical power costs across the country indicates that ammonia costs range between $70 and $230/ton and electricity costs range between $0.0275 and $0.08/kWh.[2-5]

The sensitivity of Thermal $DeNO_x$ costs to regional ammonia and electricity prices was estimated for two model plants. The 2,000 tpd RDF plant was selected, since this plant had the highest annualized costs and lowest cost effectiveness of the model plants evaluated in Sections 5.1 to 5.7. The other model plant selected was the 800 tpd mass burn/waterwall plant. This plant was the smallest plant size with a cost effectiveness of near $3,000/ton or less. The ammonia price was varied from a baseline cost of $200/ton, which was used to cost the model plants in Sections 5.1 to 5.7, to $100 and $400/ton. The results of this analysis are presented in Section 5.8.1. Electricity price was also varied from $0.046/kWh, which was used in Sections 5.1 to 5.7, to $0.0275 and $0.08/kWh. The ammonia price used when varying the electricity prices was $200/ton. The results of varying the electricity prices are presented in Section 5.8.2.

In addition, costs and cost effectiveness of Thermal $DeNO_x$ at 60 percent NO_x reduction are reported in Section 5.8.3 for both model plants. Ammonia and electrical prices were the same as used previously in Sections 5.1 to 5.7 (i.e., $200/ton for ammonia and $0.046/kWh for electricity).

5.8.1 Ammonia Price Variation

Table 5-16 presents the impacts of varying ammonia prices ($100/ton and $400/ton) on Thermal $DeNO_x$ annualized costs and cost effectiveness for the 800 tpd mass burn/waterwall model plant and the 2,000 tpd RDF model plant. As shown in this table, the cost and cost effectiveness of Thermal $DeNO_x$ are insensitive to the ammonia price variations. A 50 percent decrease in the ammonia price (from $200 to $100/ton) results in a small decrease in annualized costs and cost effectiveness (up to 8 percent) for both model

TABLE 5-16. IMPACTS OF VARYING AMMONIA PRICE ($/TON) ON THERMAL $DeNO_x$ ANNUALIZED COST AND COST EFFECTIVENESS

Combustor Type[a]	Combustor Size, tpd	Ammonia Price, $/ton	Annualized Cost, $1,000	Cost Effectiveness $/ton	Percent Change[b]		
					Ammonia Price	Annualized Cost	Cost Effectiveness
MB/WW	800	200[c]	582	2,790	-	-	-
		400	638	3,060	100	10	10
		100	553	2,660	-50	-5	-5
RDF	2,000	200[c]	1,160	1,810	-	-	-
		400	1,330	2,080	100	15	15
		100	1,070	1,680	-50	-8	-8

[a] MB/WW = mass burn/waterwall
RDF = refuse-derived fuel

[b] Percent change is calculated from the cost results at $200/ton for ammonia.

[c] Used to estimate model plant costs in Sections 5.1 to 5.7

plants. The respective annualized costs and cost effectiveness based on \$100/ton for ammonia are \$553,000 and \$2,660/ton for the 800 tpd plant and 1,070,000 and \$1,680/ton for the 2,000 tpd RDF plant. Similarly, a 100 percent increase in ammonia price (from \$200 to \$400/ton) results in a small increase in annualized costs and cost effectiveness (up to 15 percent) for both plants. The respective annualized costs and cost effectiveness based on \$400/ton for ammonia are \$638,000 and \$3,060/ton for the 800 tpd plant and \$1,330,000 and \$2,080/ton for the 2,000 tpd plant.

5.8.2 Electricity Price Variation

Table 5-17 presents the impacts of varying electricity prices on Thermal $DeNO_x$ annualized costs and cost effectiveness for the 800 tpd mass burn/waterwall model plant and the 2,000 tpd RDF model plant. Thermal $DeNO_x$ annualized costs are estimated based on electricity prices of \$0.046, \$0.0275, and \$0.080/kWh. As shown in this table, the costs and cost effectiveness of Thermal $DeNO_x$ are relatively insensitive to the electricity price variation seen across the country. A large change in electricity prices (up to 74 percent) results in a small change in annualized costs and cost effectiveness (up to 9 percent) for both model plants. The respective annualized costs and cost effectiveness based on \$0.0275/kWh are \$561,000 and \$2,690/ton for the 800 tpd plant and \$1,100,000 and \$1,720/ton for the 2,000 tpd RDF plant. Similarly, the respective annualized costs and cost effectiveness based on \$0.08/kWh are \$620,000 and \$2,980/ton for the 800 tpd plant and \$1,270,000 and \$1,980/ton for the 2,000 tpd plant.

5.8.3 NO_x Reduction Variation

Table 5-18 presents the annualized costs and the cost effectiveness for Thermal $DeNO_x$ at 60 percent NO_x reduction for both the 800 tpd mass burn/waterwall model plant and the 2,000 tpd RDF model plant. The cost results at 60 percent NO_x reduction are compared to those at 45 percent NO_x reduction in this table.

TABLE 5-17. IMPACTS OF VARYING ELECTRICITY PRICE ($/KWH) ON THERMAL $DeNO_x$ ANNUALIZED COST AND COST EFFECTIVENESS

Combustor Type[a]	Combustor Size, tpd	Electricity Price, $/kWh	Annualized Cost, $1,000	Cost Effectiveness $/ton	Percent Change[b] Electricity Price	Annualized Cost	Cost Effectiveness
MB/WW	800	0.046[b]	582	2,790	-	-	-
		0.0275	561	2,690	-40	-4	-4
		0.08	620	2,980	74	7	7
RDF	2,000	0.046[b]	1,160	1,810	-	-	-
		0.0275	1,100	1,720	-40	-5	-5
		0.08	1,270	1,980	74	9	9

[a]MB/WW = mass burn/waterwall
RDF = refuse-derived fuel

[b]Percent change is calculated from the cost results at $0.046/kWh for electricity.

[c]Used to estimate model plant costs in Sections 5.1 to 5.7

TABLE 5-18. THERMAL $DeNO_x$ ANNUALIZED COSTS AND COST EFFECTIVENESS AT 45 AND 60 PERCENT NO_x REDUCTION

Combustor Type[a]	Combustor Size, tpd	Percent NO_x Reduction	Annualized Cost, $1,000	Cost Effectiveness $/ton	Percent Change: Annualized Cost	Percent Change: Cost Effectiveness
MB/WW	800	45[b]	582	2,790	-	-
		60	604[c]	2,180	4	-22
RDF	2,000	45[b]	1,160	1,810	-	-
		60	1,230[c]	1,440	6	-20

[a]MB/WW = mass burn/waterwall
RDF = refuse-derived fuel

[b]Used to estimate model plant costs in Sections 5.1 to 5.7

[c]Costs do not include the capital expense of combustor modifications to improve the gas residence time and mixing of ammonia with the flue gas for achieving 60 percent NO_x reduction.

The annualized cost at 60 percent NO_x reduction is $604,000 for the 800 tpd plant and $1,230,000 for the 2,000 tpd RDF plant. The increase in annualized costs over those at 45 percent NO_x reduction is 4 percent for the 800 tpd plant and 6 percent for the 2,000 tpd RDF plant. The cost increase at 60 percent NO_x reduction includes higher costs for ammonia and electricity, but does not include the capital expense of combustor modifications to increase flue gas residence time and mixing needed to achieve this NO_x reduction level.

The cost effectiveness at 60 percent NO_x reduction is $2,180 and $1,440/ton for the 800 tpd and 2,000 tpd model plants, respectively. Cost effectiveness decreases by roughly 21 percent from those at 45 percent NO_x reduction for both plants.

5.9 REFERENCES

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15. SUPPLEMENTARY NOTES

16. ABSTRACT

This report characterizes nitrogen oxide (NO_x) emissions from municipal waste combustors (MWC's) and assesses the performance and costs associated with controlling NO_x emissions. Available data on NO_x emissions from MWC's are summarized. Various control technologies for reducing NO_x emissions, both combustion modifications and add-on controls, are reviewed. Performance data and operational experience for NO_x controls which have been applied to MWC's are presented.

Cost algorithms are developed for Thermal $DeNO_x$, one of the add-on control technologies that has been applied to several new MWC's. The cost algorithms for Thermal $DeNO_x$ are used to estimate annualized NO_x control costs and cost-effectiveness values for twelve model plants representative of new MWC's. The sensitivity of Thermal $DeNO_x$ annualized costs and cost effectiveness to variations in ammonia and electricity costs is also investigated.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Municipal Waste Combustors Incineration Pollution Control Nitrogen Oxides	Air Pollution Control	13B

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