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PENNSAUKEN
RESOURCE RECOVERY PROJECT

BACT Assessment for Control of NO_X Emissions
Top–Down Technology Consideration

An Ogden Company

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1. INTRODUCTION

The Pennsauken Resource Recovery Facility began its administrative review by NJDEP and USEPA Region II, for the Prevention of Significant Deterioration (PSD) permit only, when the Final Environmental and Health Impact Statement (FEHIS) and all permit applications were accepted as administratively complete in January 1987. This submission included the necessary evaluation of air pollution control equipment to determine the Best Available Control Technology (BACT) for use at the facility. The technical review of these materials, which included several exchanges of comments by the reviewing agencies - though addressing many issues in addition to those germane to the PSD permit - and responses by the applicant, continued throughout 1987. All permits were issued for public notice on January 2, 1988. A public hearing was held on February 2, 1988. Permits, including the PSD, were issued as final by NJDEP on June 30, 1988.

In response to a petition and pursuant to a citizen petition based upon federal regulation, 40 CFR 124.19, the Administrator of USEPA reviewed the PSD permit to ensure that the emission limit and BACT determination for oxides of nitrogen (NO_X) was consistent with all policies and guidelines of USEPA. After the Administrator considered the points raised by those requesting review and the record, the Administrator remanded the permit back to NJDEP.

This Remand Order, dated November 10, 1988 was predicated mainly on the fact that guidance had been sent to Regional Administrators of USEPA by the Assistant Administrator for Air on December 1, 1987 directing that all BACT assessments were to employ a method of evaluating control technologies called "top-down". The Order suggested that all PSD permits that had not completed all phases of administrative review and public comment by the date of the guidance should follow the "top-down" approach.

This BACT assessment for NO_X emission controls is being performed according to the top-down methodology as a result of the Order by the Administrator of USEPA. The Order directed NJDEP to reopen the PSD permit review proceedings to allow for the original BACT determinations to be supplemented and re-evaluated in a manner considered to be top-down. The materials which follow are in keeping with the Order and at the direction of NJDEP as to the technologies to be evaluated and the issues which bear consideration by the applicant in such a review.

1.1 BACT Definition

BACT is defined in the PSD regulations, at 40 CFR 51.166(b)(12) as follows:

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

Two guidance documents, the "Guidelines for Determining BACT" and the "PSD Workshop Manual" were published by the EPA to assist states or the regional EPA offices in making BACT determinations. The BACT requirements are intended to ensure that the control system incorporated in the design of a facility proposed in an attainment area reflects the latest in control technology used in a particular industry in keeping with local air quality, energy, economic, and other environmental considerations. They are not, however, to be as stringent as Lowest Achievable Emission Rate (LAER) requirements for new sources in non-attainment areas, where public health considerations are a paramount concern.

Guidance on preparation of BACT evaluations has been further specified by the EPA in a December 1, 1987 memorandum (Potter) to all of the EPA Regional Administrators. The memorandum directs the EPA's Office of Air Quality Planning and Standards (OAQPS) to proceed with developing specific guidance on a new approach to BACT: the "top-down" BACT, as explained therein:

> "The first step in this approach is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Thus, the "top-down" approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available. It also differs from other processes in that it requires the applicant to analyze a control technology only if the applicant opposes the level of control; the other processes required a full analysis of all possible types and levels of control above the baseline case."

Though more specific guidance on the "top-down" process, which at this time is an unofficial guideline, has not yet been developed by OAQPS, the EPA asserts that all BACT determinations for permits for which the public comment period closes later than December 1, 1987, be must prepared using this approach.

1.2 Determining the Lowest Achievable Emission Rate

The first step in the "top-down" type of analysis is determining the most stringent control available for a similar or identical source or source category. According to several references, including the Environment Reporter (4/8/88, page 2427), "companies building new facilities would be required to achieve the lowest achievable emission rate (LAER) unless they could prove the controls are economically or technologically infeasible."

LAER is defined in the Clean Air Act. This definition is somewhat expanded as LAER is defined in the New Jersey Emission Offset Rules as:

> "The rate of emission from any equipment, facility, or control apparatus which incorporates advances in the art of air pollution control developed for the kind and amount of air contaminant emitted by the equipment or facility. For the purposes of this subchapter, advances in the art of air pollution control shall result in an emission limitation at least as stringent as:
>
> 1. The most stringent emission limitation which is contained in the implementation plan of any state for such class or category of equipment or facility, unless the owner or operator of the proposed equipment or facility demonstrates that such limitations are not achievable; or

2. The most stringent emission limitation which is achieved in practice by such class or category of equipment or facility, whichever is more stringent. In no event shall the application of this term permit proposed new or altered equipment or facilities to emit any pollutant in excess of the amount allowable under applicable federal new source standards of performance."

LAER is determined by contacting federal, state and local air pollution authorities, by consulting each State Implementation Plan (SIP), by reviewing the BACT/LAER Clearinghouse (U.S. EPA 1985; 1986; 1987; 1988) and through air pollution control device vendors, consultants and literature.

1.3 Economic, Energy and Environmental Impacts

Under the top-down approach as interpreted by USEPA, once LAER is determined for the source category, an analysis of its technical feasibility, applicability, advantages and disadvantages should be prepared. If it is clear that the applicant will propose LAER as BACT for that pollutant, further analysis is not required. If LAER is not chosen as BACT, the applicant must provide further analysis to justify that decision. The analysis must quantify, to the extent possible, the economic, energy and environmental impacts which are briefly explained below.

Environmental Impacts - The net environmental impact, including both beneficial and adverse impacts, should be discussed and quantified, if possible. The analysis should consider not only pollutants regulated by the Clean Air Act, but also any other pollutants which may have a significant impact, such as dioxins, furans, acid gases and heavy metals.

Energy Impacts - To assess the energy impacts of a given control alternative, the energy consumption (Btu's, kWh, barrels of oil, etc.) should be calculated.

Economic Impacts - In the economic impacts analysis, the applicant should estimate the approximate capital and annualized costs of the different emission control alternatives. An analysis of the cost of the control options on the basis of cost effectiveness (the operating cost per ton of pollutant controlled) should be given primary consideration.

The following sections comprise the BACT analysis for control of nitrogen oxides emissions from the proposed Pennsauken Resource Recovery Facility.

2. FORMATION OF NO_X

Combustion processes produce oxides of nitrogen (NO_X) emission as a result of the oxidation of nitrogen compounds in the fuel (fuel NO_X) and of the oxidation of atmospheric nitrogen (thermal NO_X) during combustion. Formation of NOX is dependent on several factors, including temperature, pressure and residence time in the combustion unit. A lower uniform temperature and/or uniform mixing of air and fuel generally reduce oxygen (O_2) concentration gradients and temperature gradients during combustion. These gradients contribute to NO_X formation. However, state-of-the-art municipal solid waste furnaces are designed for complete combustion of organic gases utilizing high temperature combustion over longer residence times. These design criteria, which are required by New Jersey (NJDEP, April 1987), tend to contribute directly to thermal NOX formation (CARB, 1984).

Emissions of NO_X from mass-burn incinerators, without add-on controls for NO_X emissions, have been quite variable from unit to unit. This would be expected as a result of differences in waste composition, underfire and overfire air supply, combustion temperature, and grate design. Table 2-1 presents data on measured NO_X emissions from a number of mass-burn facilities in the United States (EPA, 1987a). These data represent observed flue gas concentrations without add-on NO_X controls. The NO_X concentrations vary between 39 and 376 parts per million, dry volume basis (ppmdv), in the flue gas. Most MSW combustion facilities which have received permits in the last two to three years have been required to meet a permit condition for a minimum furnace temperature and residence time which would result in increased NO_X emissions. These conditions have been recommended by USEPA in order to minimize emissions of organic substances and carbon monoxide (CO) (USEPA, 1987b). However, many of the facilities listed in Table 2-1 predate these requirements and do not meet this temperature condition. Therefore, the applicability of many of the data points in Table 2-1 to the proposed Pennsauken facility

TABLE 2-1

MEASURED NO_x DATA FROM INCINERATOR FLUE GAS IN THE U.S.

Facility	NO_x Concentration (ppmdv)	Corrected to	Reference
Baltimore	196	12% CO_2	1
Braintree	153	12% CO_2	1
McKay Bay (Unit 1)	103	12% CO_2	1
McKay Bay (Unit 2)	39	12% CO_2	1
McKay Bay (Unit 3)	100	12% CO_2	1
McKay Bay (Unit 4)	106	12% CO_2	1
Tulsa (Unit 1)	358	12% CO_2	1
Tulsa (Unit 2)	376	12% CO_2	1
Gallatin	140	12% CO_2	1
Philadelphia (NW 1)	195	12% CO_2	1
Philadelphia (NW 2)	215	12% CO_2	1
Marion County	294	12% CO_2	1
Commerce	165-281*	3% O_2	2

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* Represents concentration upstream of ammonia injection control system.

(1) EPA, 1987a

(2) McDannel and McDonald, 1988b.

is questionable. For example, the Braintree Facility, which had a NO_X emission level of 153 ppmdv, operated with only underfire air at a combustion zone temperature of 1160°F (EPA, 1987a), which resulted in the high CO concentration of 1,350 ppmdv. Likewise, the Gallatin Facility had a low NO_X concentration of 140 ppmdv but also had a high CO concentration of 516 ppmdv. The Philadelphia incinerators had NO_X concentrations of approximately 200 ppmdv but also had CO concentrations ranging from 464 to 515 ppmdv (EPA, 1987a). These CO measurements would not comply with NJDEP guidelines (NJDEP, April 1987). By comparison, modern facilities such as Tulsa, Marion County, and Commerce have higher NO_X concentrations in the flue gas compared to those older facilities, but extremely low CO concentrations (20 ppmdv, 15 ppmdv, and 12 ppmdv, respectively). No combustion zone temperature data are available to explain the low NO_X emissions at McKay Bay (USEPA, 1987a). The Tulsa, Marion County, and Commerce facilities are those with required high combustion temperatures for control of organic and CO emissions. These higher combustion temperatures result in a greater conversion of fuel nitrogen to NO_X and additional thermal NO_X. The data from Commerce are probably less comparable to the Pennsauken situation, since the bulk of the waste received at Commerce is commercial rather than residential waste (McDannel and McDonald, 1988a).

Facilities employing the Martin grate, such as that planned for the proposed facility, have been observed to consistently produce among the lowest emissions of dioxins, furans, and other organic substances measured anywhere in the world (Hahn and Sussman, 1986; Zurlinden et al., 1987a, Zurlinden et al., 1987b). Therefore, it is not meaningful to compare data on NO_X emissions from facilities that do not have to meet today's more stringent requirements for high efficiency combustion.

Table 2-2 is an excerpt of NO_X emission data for Ogden Martin facilities tested in the U.S. (Hahn and Sofaer, 1988). These hourly values vary from 252 ppmdv to 389 ppmdv at 12% CO_2. Much of this variation may be due to seasonal factors. Figure 2-1 shows the seasonal variation of measured NO_X concentrations. As shown in this figure, NO_X emissions decrease with colder weather, possibly a result of less vegetative matter, and thus less nitrogen, in the waste. Short-term maximum NO_X emission rates, therefore, must reflect the fact that large seasonal changes in fuel nitrogen occur.

Another factor that should be considered is the hour-to-hour variation in NO_X emissions. Table 2-3 presents 168 hours of continuous NO_X emissions at the Marion County Facility. These data show that hourly NO_X concentrations can vary more than 120 ppmdv during a single day under normal operating conditions (Hahn and Sofaer, 1988).

As a result of the above considerations it can be concluded that the quantities of NO_X produced during the combustion process at the proposed Pennsauken facility must be characterized by measurements at facilities that are operating at the combustion conditions required to minimize formation of dioxins and other organics similar to those required by NJDEP. The subset of these facilities using the Martin technology are

TABLE 2-2

HOURLY NO_x EMISSIONS TEST DATA FROM OGDEN MARTIN FACILITIES

Facility	Test Date	Combustion Unit	Concentration ppmdv @ 12% CO_2 1-hr average
Tulsa	June 1986	Unit 1	362
			356
			345
			377
		Unit 2	371
			389
			389
			374
			357
	October 1986	Common Stack	258
			256
			252
	September 1987	Unit 3	329
			331
			335
Marion	October 1986	Unit 1	271
			299
			349
		Unit 2	240
			302
			308
Hillsborough	April 1987	Unit 1	301
			341
			323
		Unit 2	325
			336
			325
		Unit 3	323
Bristol	January 1988	Unit 1	316
			266
			261
		Unit 2	268
			270
			297

Source: Hahn and Sofaer, 1988.

TABLE 2-3

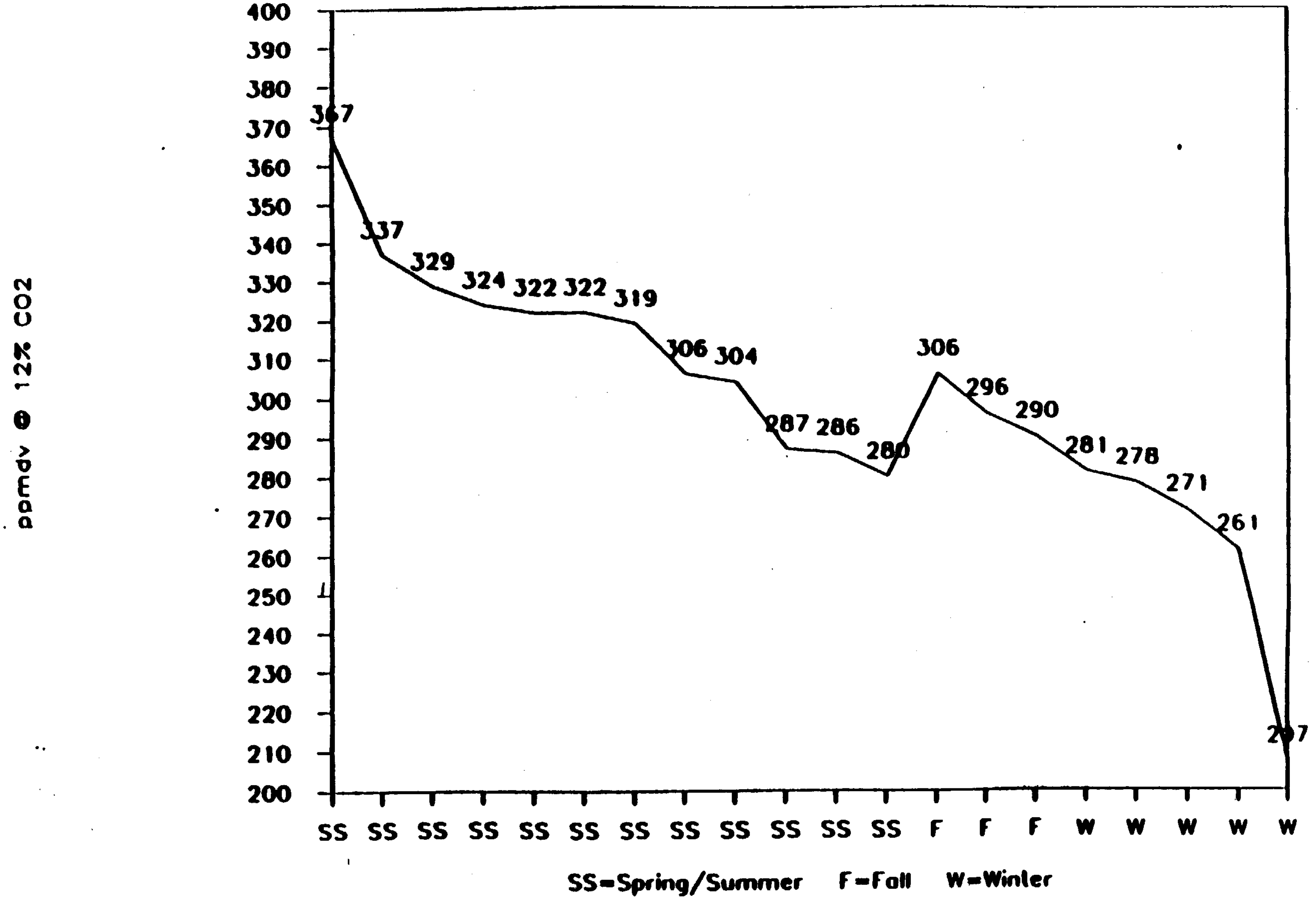
HOURLY AVERAGE NO_x EMISSIONS OVER 168 HOUR PERIOD AT THE MARION COUNTY RESOURCE RECOVERY FACILITY

	Hourly Average NO_x Emissions (ppmdv @ 12% CO_2)							
Hr	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8
1	246	323	313	N/A	271	251	270	270
2	264	316	310	N/A	249	245	267	275
3	273	283	316	N/A	257	250	302	288
4	275	279	281	N/A	245	238	282	262
5	277	286	289	256	251	267	302	262
6	251	278	247	286	294	234	275	276
7	256	279	256	272	258	260	282	286
8	260	282	255	267	287	245	277	274
9	238	302	248	282	302	268	296	
10	248	313	294	300	285	248	277	
11	250	285	264	276	287	264	288	
12	264	343	238	281	257	262	272	
13	261	283	266	316	277	232	240	
14	288	275	270	304	298	242	258	
15	267	242	281	296	318	287	261	
16	272	258	259	290	314	246	259	
17	284	245	237	281	259	278	248	
18	258	261	300	298	250	264	251	
19	273	246	268	292	299	228	264	
20	271	221	278	251	284	259	297	
21	258	266	N/A	267	237	245	263	
22	286	309	N/A	218	251	258	275	
23	280	304	N/A	246	258	265	266	
24	347	283	N/A	265	254	261	287	
Average	269	282	273	277	270	254	273	274
Range	347-246	343-221	316-237	316-218	318-237	287-228	302-240	288-262
Average CO_2 during test:								
	7.5	7.5	7.5	7.6	7.5	7.6	7.4	7.5
Range of CO_2 during test:								
	7.3-7.8	7.3-7.7	7.2-8.1	7.4-7.8	7.3-7.8	7.3-7.8	7.1-7.6	7.3-7.7

Reprinted from: Hahn and Sofaer, 1988, Table IV.

FIGURE 2-1

Seasonal Variations in NOx Emissions



Source: Hahn and Sofaer (1988)

the most appropriate data points as Ogden Martin Systems has been selected by Pennsauken as the system vendor. NO_X data from Ogden Martin facilities in the U.S. indicated that maximum hourly uncontrolled concentrations of NO_X in the flue gas can exceed 350 ppmdv at 7% O_2, while the 3-hour average should not exceed this value.

3. NO_X CONTROL ALTERNATIVES

Both combustion controls and post-combustion techniques are available to minimize NO_X emissions from municipal solid waste (MSW) incinerators. Combustion controls practiced on modern mass-burn systems include providing optimal underfire and overfire air, controlling grate speed, and waste feed rate. Modified combustion systems use flue gas recirculation. Post-combustion NO_X controls include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), more commonly referred to as ammonia injection. Other post-combustion controls, such as dry NO_X/SO_2 control processes, including carbon adsorption, electron beam irradiation and the copper oxide process, as well as wet techniques, such as absorption-reduction and oxidation-absorption, are still in the development stage or have been abandoned for economic reasons and thus are not considered available technologies.

Incinerator design and control of the furnace operating parameters will be used to ocntrol the emissions of NOX, CO, VOC and trace organics from the proposed facility. Furnace temperature, residence time, mixing of combustion air and fuel-derived gases, and the proper amount of excess air are all important factors in limiting the emissions of these pollutants. The rate of NOX formation increases with increasing temperature and residence time, while high temperature and long residence time are necessary to achieve the high combustion efficiency that is needed to limit CO emissions and destroy trace organics and VOCs. This opposing relationship limits the exten to which incinerator design can control all of these pollutants. The emphasis placed on minimum combustion temperature and residence times expressed in New Jersey DEP and USEPA guidelines indicate that the control of organic emissions is the first priority.

The following "top-down" BACT analysis for NO_X emissions addresses SCR, ammonia injection, flue gas recirculation and combustion controls, in that order.

3.1 Lowest Achievable Emission Rate (LAER)

The approach to determining LAER in this analysis is to examine the NO_X removal efficiencies permitted, guaranteed or pilot-tested on other types of combustion facilities.

Based on the <u>BACT/LAER Clearinghouse</u> and vendor literature, the lowest achievable NO_X emission rate from combustion sources in general appears to be 5% of the uncontrolled NO_X emissions (i.e. 95% reduction). This type of reduction has never been demonstrated or attempted on a municipal waste incinerator. The control technologies able to achieve ninety-five percent NO_X reductions have only been demonstrated on commercial coal, gas and oil-fired boilers and gas turbines. The highest NO_X removal from an MSW incinerator was 77% as averaged over 12 tests on a unit in Japan equipped with selective catalytic reduction. Therefore, for purposes of identifying LAER specifically for MSW incinerators, LAER is the achievement of 77% of NO_X reduction using selective catalytic reduction technology. This is equivalent to a controlled hourly emission rate of 23.9 pounds at the proposed Pennsauken facility.

3.1.1 Process Description

In the SCR process, anhydrous ammonia (NH_3) is injected into the flue gas stream whereupon intimate mixing occurs between the ammonia and NO_X, which is predominantly NO at this point. The mixture then passes through a catalyst bed, often located between the boiler and economizer in typical combustion operations, such that reduction of NO to N_2 is promoted according to the following reaction:

$$NO + NH_3 + 1/4\ O_2 \longrightarrow N_2 + 3/2\ H_2O.$$

The function of the catalyst is to lower the activation energy of the NO decomposition reaction to N_2. In other words, if there were no catalyst, the reaction would have to take place in the furnace (or other location) where the temperature ranges from 1600 - 1800°F, the necessary temperature window for NO decomposition. With the catalyst, however, the optimum temperature required for NO reduction is between 530 and 800°F. If the catalyst were placed in a location with a lower temperature, the reaction rates would decrease. Catalyst location at higher temperatures would impair the catalysts performance and shorten catalyst life.

The catalyst itself is comprised of base metals such as vanadium, titanium, molybdenum, and platinum. The catalysts are sold in several shapes, such as honeycomb grids, parallel ridged plates, rings, tubes, or pellets. Each form has advantages and disadvantages with respect to NO_X contact, catalyst fouling, and pressure drop.

Three types of catalyst bed configuration are currently under study or have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The moving bed is characterized by the catalyst circulating through the reactor; this type of process is applicable to sources with high particulate loading in the flue gas. The parallel flow reactor is distinguished by the shape of the catalyst bed and the orientation of the bed with respect to the flue gas flow. The beds are arranged parallel to the gas flow, thereby preventing impaction of particulate on the catalyst surface while still promoting the reduction reactions through diffusion of the reaction species into the bed. This reactor type is similarly suited for sources with high particulate flue gas loading and is often used in coal combustion. Fixed bed reactor design is applicable only to sources with little or no particulate present in the flue gas. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow and transport of the reactants to the active catalyst sites takes place through a combination of diffusion and convection mechanisms.

3.1.2 Operating Experience and Applicability to MSW Incineration

SCR has been applied extensively on a developmental basis to oil-, gas- and coal-fired boilers in Japan and Europe; has been tested on oil- and gas-fired boilers in the United States; and has been applied to coal-fired boilers in the U.S. on a limited basis. High reductions have been achieved on full-scale operations with the catalyst located both upstream and downstream of the particulate control device (CARB, 1984, Mobley, 1979).

Experience with SCR on MSW incinerators, on the other hand, is extremely limited. There are no MSW incinerators in the United States currently employing SCR for NO_X control. Historically, testing of SCR on refuse-fired boilers in Japan revealed difficulties, primarily due to catalyst fouling by particulates and condensibles. In applications where the catalyst was upstream of the particulate removal device, the relatively high particulate grain and/or condensable loading of the flue gas fouled the catalyst, rendering the bed ineffective in NO_X removal. Particulates eroded the catalyst and substrate material, and poisoned or blinded the catalyst. For these reasons, SCR was not considered demonstrated on resource recovery facilities as of 1987. According to EPA Region 9 (1987), although 90-95% control had been achieved on pilot tests (MSW-firing) and numerous gas and oil-firing units, "this control technology had not yet been applied to refuse combustion, and had not been considered as a transferable technology due to yet unresolved technological problems."

According to EPA (1987c), earlier SCR problems such as catalyst poisoning by SO_X, plugging, ammonium bisulfate deposition, production of SO_3 and erosion of catalyst had generally been overcome on other types of combustion units. However, in scenarios where conventional SCR catalysts (which use base metal with titanium oxide) were placed at the economizer outlet (to take advantage of the optimum temperature range of 530-800°F), attack of catalyst by hydrochloric acid (HCl) was still a problem. Current research efforts are focusing on developing high temperature catalysts resistant to HCl attack, metals poisoning, and high particulate loadings.

Acid gas attack, metals poisoning and particulate fouling may be avoided by placing the catalyst downstream of the pollution control equipment. This is undesirable, however, for two reasons: (1) conventional catalysts do not perform well at these lower temperatures and (2) flue gas reheat is needed to raise the flue gas temperatures to the optimum range, the latter imposing severe energy penalties. In order to avoid flue gas reheat, scientists are also researching low temperature SCR catalysts.

Shell-Universal Oil Products (UOP) was very active in the late 1970s and early 1980s in the research and development of high- and low-temperature catalysts. A low-temperature, parallel-passage catalyst was constructed and pilot-tested at an iron-ore sintering process at Nippon Steel on Japan (CARB, 1984). After 1200 hours of testing, the overall NO_X control efficiency was 96%. Pilot-scale tests of a high-temperature parallel-flow catalyst at a coal-burning station in the Netherlands successfully reduced NO_x emissions (though no actual NO_X reductions were reported) in a flue gas stream containing 8.7 grains of particulates per dry standard cubic foot. Though the low- and high-temperature catalysts looked promising, based on preliminary R&D activity, the marketplace was not ready for the products, no one could afford the system, and UOP could no longer afford to develop the product (UOP, 1988). Shell-UOP has since abandoned its research efforts.

Mitsubishi Heavy Industries (MHI) has developed a special low temperature, acid-resistant catalyst. The only two resource recovery facilities equipped with SCR (EPA, 1987c) use these special catalysts: 1) the Hikarigaoka facility in Tokyo, Japan, which has one 150 ton-per day (tpd) incinerator and 2) the Iwatsuki facility in Japan, which has two incinerators, each sized at 65 tpd. The 150 tpd plant, which has been operating with SCR since December 1986, is a retrofit application which had a very limited space for catalyst addition. The design NO_X removal was consequently only 30-40% for an uncontrolled flue gas NO_X concentration of 120 ppmv. The catalyst is located downstream of an ESP and upstream of a sodium-based wet scrubber (EPA 1987c). The other system, also developed by MHI, follows a lime spray dryer/baghouse system. This system, which has been operating since February 1987, was designed to achieve 73% NO_X removal (to achieve 40 ppm) though the guarantee is only for 33% NO_X removal (for an outlet NO_X concentration of 100 ppmv) (EPA, 1987c). The flue gas temperature in that application is 392°F. It should be noted that the "acid-resistant" catalysts in these two applications treat flue gas containing 500-800 ppmv HCl and 50 ppmv HCl, respectively.

SCR is also being applied to sludge incinerators in Japan. At least 15 SCR plants on municipal sludge incinerators have been constructed by MHI. Because MHI was concerned with catalyst degradation caused by HCl and trace metals in the flue gas, the catalysts were placed downstream of the HCl/trace metal removal devices. The design NOx removal rates from these facilities range from 80-90%. Performance data on all of these Japanese MSW and sewage sludge incineration facilities are not available at this time (EPA, 1987c).

As shown by these Japanese facilities, SCR may be considered available for NO_X control on MSW incinerators, although circumstances suggest it meets LAER, not BACT, criteria.

3.1.3 Observed Control Efficiencies

As previously stated, NO_X reductions up to 95% have been achieved on numerous coal, gas and oil-fired boilers, as well as gas turbines, both in the U.S. and abroad.

Experience on the two small Japanese MSW incinerators, both equipped with low temperature catalysts, shows that both systems performed as designed. According to the data presented in Table 3-1, the SCR system at Iwatsuki, which was designed for 73% removal, performed quite well, with an average control efficiency of 76.9%. The range of NO_X removal over 12 tests was 62.5% to 86.4%. SCR performance at the Tokyo-Hikarigoaka facility, which was designed for 30-40%, averaged 43.9% over six tests, with NO_X reductions in individual tests ranging from 25.5% to 57.1%. The two facilities had equivalent NH_3 injection rates (a 1:1 molar ratio with NO_X), although the reactor inlet temperature at Tokyo-Hikarigaoka reactor was about 72°F higher.

In summary, testing at these two SCR-equipped MSW incineration facilities indicates NO_X reductions ranging from 25.5% to 86.4%. The average NOx removal efficiencies from these two facilities were 43.9 and 76.9%. The EPA (1987c) estimates that SCR may only control NO_X by 30 to 50%. Though no data exist to establish long-term trends in control efficiency of the catalyst it is assumed that the higher demonstrated average NO_X removal of 76.9% is LAER for MSW incinerators.

3.1.4 Advantages of SCR

Economic Impacts

There are no favorable economic impacts associated with SCR.

TABLE 3-1

OBSERVED CONTROL EFFICIENCY ASSOCIATED WITH SCR INSTALLATIONS AT TWO MUNICIPAL INCINERATORS IN JAPAN

Facility	Reactor Inlet Temp (°C)	NO_x Emissions (ppm)(1) Inlet	NO_x Emissions (ppm)(1) Outlet	Removal efficiency (%)
Iwatsuki	196	123	30.2	75.4
	198	129	25.6	80.2
	204	129	29.4	77.2
	198	195	38.0	70.2
	202	173	26.2	84.9
	205	138	41.2	70.2
	202	110	15	86.4
	205	100	16	84.0
	200	130	30	76.9
	207	120	45	62.5
	200	160	36	77.5
	203	130	29	77.7
Tokyo-Hikarigaoka	248	96	63	34.4
	248	95	47	50.5
	246	106	79	25.5
	244	104	60	42.3
	245	93	42	57.1
	246	101	47	53.5

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(1)Corrected to 12% O_2.

Source: Mitsubishi, 1987.

Energy Impacts

There are no favorable energy impacts associated with SCR.

Environmental Impacts

SCR is the technology capable of achieving 77% NO_X reduction, the LAER for MSW incineration based on 77% reduction in NO_X measured at a Japanese facility. At this reduction, annual NO_X impacts from the proposed Pennsauken Resource Recovery Facility would decrease from 0.41 ug/m^3, calculated in the original modeling analysis presented in the FEHIS, to 0.09 ug/m^3 at the point of maximum impact.

Other favorable environmental impacts would include lower ammonia slip (when compared to ammonia injection systems), as well as the fact that SCR produces no continuous solid or liquid waste stream.

3.1.5 Disadvantages of SCR

Technical Disadvantages

Although vendors are trying to develop catalysts suitable for high grain loadings, high temperatures and effective acid-resistance, a successful SCR system for the proposed MSW incinerator would necessitate placing the catalyst bed downstream of the acid gas removal equipment. Unfortunately, the temperature at this location is 275°F, which is below the minimum temperature required for effective operation of low temperature, acid-resistant catalysts (392°F) or conventional catalysts (572°F). The flue gas would have to be reheated to raise the temperature to between 392°F and 572°F, depending on the catalyst selected, a significant operating expense (see Table 3-2).

Flue gas reheat, which may be accomplished by a number of means (e.g. in-line, indirect hot air, direct combustion, or bypass) has presented operating problems in the past (Froelich, 1987). Initially it appeared that stack gas reheat should be employed on conventional combustion applications to prevent corrosion of downstream equipment and to improve environmental effects (mostly associated with pollutant dispersion, liquid fallout and plume visibility). It was thought that simple heat exchangers inside or outside the ductwork environment could be used at relatively high operability rates. This has not proven to be the case. As stated in JAPCA (Froelich, 1987), "while corrosion prevention (even downstream of acid gas removal devices) is the most commonly cited reason for using flue gas reheat, stack gas reheat systems have been subject to the very problems reheat was intended to prevent". Besides acid-corrosion, JAPCA cited the reduction in net heat transfer rates, increased energy costs, the need for complete reheat tube removal, and pluggage of tube bundles as associated problems typically encountered with stack gas reheat. The most significant disadvantage to use of a reheat system is cost, which affects all economic areas: capital cost, maintenance expenses and operating costs. "Stack gas reheat systems have tended to be one of the greatest maintenance nightmares in the flue gas desulfurization (FGD) experience. At many facilities, reheat has been the single largest factor in reduced FGD availability" (Froelich, 1987).

Another disadvantage is that the catalyst, which is the most costly part of the SCR system, is subject to loss of activity over time. Catalysts deactivate by physical and chemical means. Physical deactivation is caused by either catalyst exposure to excessive temperatures (thermal degradation) or catalyst masking due to entrainment of particulates in the flue gas (fouling). While thermal degradation is not expected to be a problem, Mitsubishi Heavy Industries' main concern with the application of SCR to proposed MSW incinerators is fouling.

Chemical deactivation is caused by irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or reversible adsorption of a contaminant on the surface (inhibition). Metals are typical catalyst poisons. Inhibitors can be removed from the catalysts by blowing the catalyst clean with compressed air, washing in an appropriate solution, or cycling at elevated temperatures in a non-contaminated stream.

Despite the ability to wash a catalyst (or otherwise regenerate it), a certain loss in catalyst activity is unavoidable. MHI generally only guarantees a two-year catalyst life. Catalyst replacement or repair would require Facility downtime due to the system being integral to the boiler and the gas passages.

One of the main disadvantages is that there are no long-term SCR operating data on resource recovery facilities. Experience with SCR applied to MSW combustion is limited to the two aforementioned facilities in Japan which both have operated for less than two years. Therefore, long-term reliability issues unique to the application of SCR to MSW incineration are unknown.

Economic Impacts

The main disadvantage associated with SCR is cost. SCR is expensive because of both the initial capital outlay and annual operating costs. The main capital expense is the catalyst; the main operating expenses are incurred from flue gas reheat, catalyst replacement and disposal and ammonia requirements.

Estimated capital and annual operating costs of control for a 77% efficient SCR system on the proposed Pennsauken Resource Recovery Facility are shown in Table 3-2. These estimates were based on general costs presented in literature, McElroy (1983). The installed capital cost of SCR at the proposed 500 TPD MSW incineration facility would be about $5.7 MM in 1983 dollars. Flue gas reheat costs, however, depend on whether a conventional catalyst (requiring reheat from 275°F to 570°F) or a special "low temperature, acid resistant" catalyst (requiring reheat from 275°F to 390°F), is recommended by the vendor. The reheat costs could vary from $0.5 MM to $1.4 MM, giving a total annual operating expenditure of $1.8 MM to $2.7 MM.

TABLE 3-2

ESTIMATED CAPITAL AND OPERATING COSTS FOR SCR

Total Installed Capital Cost(1)	$5,700,000
Operating Costs	
Catalyst(1)	1,660,000
Ammonia(1)	82,000
Labor(1)	74,000
Flue Gas Reheat(2)	460,000 - 1,400,000
Subtotal	$1,782,000 - 2,722,000
Annualized Capital Cost	624,000
Total Annual Operating Cost	$2,406,000 - 3,346,000
Tons NO_X Removed Per Year	350
Cost Effectiveness	$6,870/ton to $9,560/ton

Flue Gas Density:

0.075 lb/cu. ft @ discharge temperature of 270°F

Mass of Air to be Heated:

$$92{,}616\ \frac{\text{acf}}{\text{min}} \times \frac{(460 + 68)^\circ\text{R}}{(460 + 270)^\circ\text{R}} \times 0.075\ \frac{\text{lb}}{\text{ft}^3} \times 60\ \frac{\text{min}}{\text{hr}} = 301{,}500\ \frac{\text{lb}}{\text{hr}}$$

TABLE 3-2

ESTIMATED CAPITAL AND OPERATING COSTS FOR SCR

(continued)

Enthalpies of Air:

@ 275°F = 51.8 Btu/lb

@ 390°F = 79.7 Btu/lb

@ 570°F = 136.6 Btu/lb

Flue Gas Reheat Energy Requirements:

- Assume any exchanger is 80% efficient
- Unit cost of reheat is $5/MMBtu

Lower Valve:

$$301{,}500\ \frac{\text{lb}}{\text{hr}} \times (79.7 - 51.8)\ \frac{\text{Btu}}{\text{lb}} \times \frac{\text{MMBtu}}{10^6\text{Btu}} \times \frac{1}{0.8} = 10.5\ \frac{\text{MMBtu}}{\text{hr}}$$

Upper Valve:

$$10.5\ \frac{\text{MMBtu}}{\text{hr}} \times \frac{(136.6 - 51.8)}{(79.7 - 51.8)} = 31.9\ \frac{\text{MMBtu}}{\text{hr}}$$

TABLE 3-2

ESTIMATED CAPITAL AND OPERATING COSTS FOR SCR

(continued)

Reheat Costs

Lower Valve:

$$10.5\ \frac{\text{MMBtu}}{\text{hr}} \times 8760\ \frac{\text{hr}}{\text{yr}} \times \frac{\$5}{\text{MMBtu}} = \$0.5\text{MM}$$

Upper Valve:

$$31.9\ \frac{\text{MMBtu}}{\text{hr}} \times 8760\ \frac{\text{hr}}{\text{yr}} \times \frac{\$5}{\text{MMBtu}} = \$1.4\text{MM}$$

Tons of NO_X removed by SCR

$$103.7\ \frac{\text{lb}}{\text{hr}} \times 8760\ \frac{\text{hr}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} \times 0.77 = 350\ \text{tpy}$$

Notes: (1)McElroy, 1983, Cost presented in 1983 dollars.

(2)Approximate Flue Gas Reheat Costs

Capital recovery may be estimated by multiplying the capital recovery factor (CRF) by the total installed capital cost, $5,700,000. The capital recovery factor (CRF) is defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where: i is the annual interest rate, and
n is the equipment life (years).

For this economic analysis, the capital recovery factor, 0.1095 (10.95%) was calculated assuming that the equipment life is 20 years and the average annual interest rate is 9.0%. Capital recovery charges are, therefore, $624,000.

Total annual operating costs including capital recovery charges range from $2.4 MM to $3.3 MM, depending on the extent of flue gas reheat required.

The lifetime of the catalyst also presents uncertainties in operating cost estimates. The SCR catalyst cost comprises about 50% (Russell, 1984) to 75% (Jelinek, 1988) of the basic equipment cost, thus, replacement (and disposal) presents significant operating costs. With less than two years' operating experience on the two Japanese facilities, it is difficult to evaluate the catalyst life.

Additional costs associated with required safety measures and equipment for onsite storage of anhydrous ammonia are not included in this SCR economic presentation. Safety, containment and control devices as required by N.J.A.C. 7:31-2.3 and 7:26-2.10(b)(6)(ii) and (iv) to prevent ammonia system overpressurization, and to control, reduce, and contain any significant releases of ammonia that may occur as a result of system failures (these measures are currently envisioned to include safety relief valves, a containment dike system, and fogging nozzles around the liquid ammonia storage tank and delivery area). These safety measures and resultant costs are similar to those required for selective non-catalytic reduction which are further discussed in Section 3.2.5.

The cost effectiveness of the 77% efficient SCR system, based on annual removal of 350 tons of NO_X, ranges from $6,870 to $9,560 per ton. These values are very high and are considerable unreasonable, especially when the actual capital and operating costs are considered: $5.7 MM and $1.8-$2.7 MM, respectively. Considering that the USEPA as well as NJDEP have <u>not</u> required ammonia injection (which costs less than SCR) on recently permitted resource recovery facilities in New Jersey and elsewhere across the nation, SCR cannot be defended as BACT, based on the extreme economic impacts alone.

<u>Energy Impacts</u>

The amount of energy required to reheat the flue gases, 10.5 to 31.9 MMBtu/hr, would be quite high regardless of the type of catalyst used. Flue gas reheat would likely entail natural gas firing since the quality of steam produced would not be sufficient to meet the thermal demand. Therefore, a substantial additional amount of fossil fuel would be consumed annually, equivalent to 92,000 to 280,000 MMBtu/year, or 260 to 800 MMBtu per ton NO_X removed (see Table 3-2). These are considerably high energy requirements which are not warranted at the proposed facility, especially considering the fact that more NO_X is generated in the process.

Environmental Impacts

One disadvantage of SCR is that while NO_X may be reduced 77%, the air quality benefit is nominal, less than 0.1% of the NAAQS.

This reduction in NO_X is gained at the expense of other negative environmental impacts. Unreacted ammonia, "ammonia slip", will be emitted, although at estimated stack concentrations of 2-10 ppmdv. The associated eight-hour average ground-level impact of 0.3 ug/m^3, however, is well below the threshold limit value (TLV) of 18 mg/m^3 established by the American Conference of Governmental Industrial Hygienists (ACGIH).

Ironically, the use of the flue gas reheat, which required fossil fuel combustion, generates its own emissions, most significantly NO_X, the pollutant that SCR is supposed to minimize. It is estimated, using AP-42 emission factors, that up to 12.5 tpy of NO_X would be generated by use of flue gas reheat.

The injection of NH_3 has been theorized to increase CO emissions, primarily due to competition for OH radicals, which assist in oxidizing

CO to CO_2 (Moilanen, et al., 1987). These CO increases were observed during testing at the Commerce MSW-incineration facility in California (McDannel, et al., 1987), at a wood-fired boiler employing SCR in Long Beach, California (Moilanen, et al., 1987), and on coal-fired circulating fluidized beds using ammonia injection (Hiltunen and Tang).

Although it was theorized that use of SCR could also cause formation of carcinogenic nitrosamines or other nitrated hydrocarbons (Eschenroeder, et al., 1987), the SCAQMD's revised draft of the Environmental Impact Report for "Proposed Rule 1134: Control of Oxides of Nitrogen from Stationary Gas Turbines" (Farris, Smith, Kneisel, 1988) has questioned the theory. This study stated that some analyses for nitrosamines had been conducted on emissions from coal-fired power plants retrofitted with SCR and on oil/gas-fired utility boilers, and that nitrosamine formation had not been detected. CARB tested the exhaust gas on a unit controlled by SCR and also did not detect nitrosamines. SCAQMD concluded in their EIR that "these tests indicate that health impacts resulting from nitrosaimine exposure are not present at facilities with SCR systems". However, there still remains a doubt among scientists on whether these carcinogenic nitrosamines are present.

The spent catalyst also requires disposal, which is complicated by the fact that these catalysts, containing various heavy metals including titanium and vanadium, are considered to be hazardous wastes. Thus, use of SCR entails hazardous waste handling and disposal, an environmental burden, as well as potential liability.

The reliable control of both ammonia and NO_X emissions are impeded by the lack of operating experience by a reliable continuous monitor for ammonia at MSW facilities. Substantial variability in the emission rate for both of these pollutants, therefore, could be expected.

Finally, anhydrous ammonia is classified as an extremely hazardous substance. In fact, its handling and storage are regulated by the New Jersey Toxic Catastrophe Prevention Act (N.J.A.C. 7:31). Environmental releases could result due to thermal expansion in the storage tank, injection control system failure to shut-off, puncture or rupture of storage tank and transfer lines, facility fire, or tank truck accidents. In fact, due to its potential for volatization (as a liquid stored under pressure) and toxic effects, ammonia would become the most hazardous substance stored at the facility. Safety measures, identified in the Risk Management Program for ammonia storage, would have to be employed to minimize risks. These measures, however, would not completely eliminate the risk.

3.1.6 Conclusions

Selective Catalytic Reduction to achieve 77% reduction in uncontrolled NO_X emissions cannot represent BACT for NO_X for the proposed Pennsauken Resource Recovery Facility, based on the tremendous costs of the system. The estimated capital cost of $3.5 MM and operating costs, ranging from $1.3 to $2.2 MM, are significantly higher than those for Thermal $DeNO_X$, a technology which both the USEPA and NJDEP have not required for recently permitted resource recovery facilities. Besides the huge costs of the system, SCR has only been used on two MSW incinerators and has not been demonstrated over the long-term. This presents significant risk when guaranteeing and demonstrating the one-hour, not-to-exceed NO_X emission limits over the 5-year life of the permit.

3.2 The Second Most Stringent Control Alternative

As concluded in the previous section on LAER for MSW-incineration, SCR at 77% control efficiency was not judged BACT for the proposed Pennsauken Resource Recovery Facility, mainly because of the high capital and operating costs coupled with the negligible reduction in ambient air impacts. In fact, use of SCR at a lower control efficiency such as 35 or 50%, could not be judged BACT for the same reasons: the capital and operating expenses would be huge, the cost effectiveness would not improve (even though costs would be less, control of NO_X would be less) and the reduction in ambient air impacts would be even more negligible. The host of other negative technical concerns and energy and environmental impacts applicable to a 77%-efficient SCR system would also apply to a less efficient SCR system, and thus the conclusions regarding SCR as BACT would be the same: SCR at 77% or lower NO_X removal efficiencies is not BACT. Therefore, the second most stringent control alternative would not entail SCR, but rather the next best technology: selective non-catalytic reduction (SNCR) a post-combustion method for NO_X control.

SNCR involves the intimate contact of injected ammonia and NO in the flue gas to control NO_X emissions, and therefore is commonly referred to as ammonia injection. The process, which was patented by Exxon Corporation in 1976 as Thermal $DeNO_X$, selectively reduces NO_X by reaction with ammonia (NH_3) which is injected directly into the combustion chamber or into a thermally favorable location further downstream. Recently improved technology has resulted in domestic commercial, other than resource recovery, facilities achieving removal performances in the 70-80% range (Exxon, 1988).

Use of Thermal $DeNO_X$ to achieve 70-80% NO_X reduction has never been demonstrated, however, on municipal solid waste incinerators. The highest achieved NO_X removals from an MSW-incinerator using Thermal $DeNO_X$ has varied from 14.5 to 62.0% (McDannel and McDonald, 1988a), as demonstrated at the Commerce facility in California. The range of control achieved depended on the combustion conditions and mode of operation, as discussed below. This section, therefore, evaluates the technological concerns, and economic, energy and environmental impacts associated with the second most stringent control alternative: use of Thermal $DeNO_X$ to reduce NO_X emissions within this observed range, to 35.7%, the maximum control efficiency to which Ogden Martin could provide a business guarantee.

3.2.1 Process Description

The process is based on a gas phase homogeneous reaction, within a specified temperature range, between NO_X in the flue gas and injected NH_3

to produce gaseous nitrogen and water vapor. The actual chemical mechanism of the process is quite complex, involving 31 significant chemical reactions. The chemical reactions governing the NO_X control process are:

$$NO + NH_3 + \frac{1}{4} O_2 \rightarrow N_2 + \frac{3}{2} H_2O \qquad (1)$$

$$NH_3 + \frac{5}{4} O_2 \rightarrow NO + \frac{3}{2} H_2O \qquad (2)$$

Critical to the successful reduction of NO_X is the prevailing temperature of the flue gas when the NH_3 is injected. In conventional combustion processes at flue gas temperatures of 1600°F to 1740°F, the first reaction dominates, reducing NO and limiting further NO production. At temperatures above 1740°F, reaction (2) becomes more significant, limiting NO reduction efficiency, and at temperatures above 2200°F, reaction (2) dominates, creating more NO, a counterproductive situation. At flue gas temperatures below 1600°F, the rate of both reactions slows down, such that some of the ammonia does not react and passes through the system into the ambient atmosphere. Research efforts have succeeded in understanding the chemical kinetics to the point where computer modeling can both predict the removal efficiency and define the optimum NH_3/NO_X ratio for virtually any conceptual application.

Thermal $DeNO_X$ is a process which is continuously being researched and engineered. Besides development of sophisticated chemical kinetics computer models, second generation NH_3 injection systems have been developed, presenting significant improvements in NH_3 mixing and NO_X removal ability. The original applications involved positioning an injection grid within the flue gas stream at the proper flue gas temperature for injecting a mixture of NH_3 and carrier steam or air. In most current applications, the use of injection grids is being replaced by the use of wall injectors, which consist of large jets located at or near the boundary walls of the injection zone. The advantages of using wall injectors include higher removal efficiencies, lower investment cost, better load following, reduced fouling tendency, better resistance to corrosive attack and better resistance to overheating caused by loss of carrier flow.

The equipment that comprises a thermal $DeNO_X$, or SNCR, system includes the following items:

- dual rows of injection headers and nozzles for each combustion unit (only one row utilized, but two provided to allow for process modifications required due to furnace temperature profile)

- necessary piping for delivery of vaporized ammonia, carrier gas, and mixed gas into the injection headers

- air compressors and reservoir to provide air for carrier gas and ammonia injection requirements (sufficient carrier gas pressure is necessary to achieve uniform distribution of ammonia throughout the combustion zone)

- ammonia storage facility, sized at 4,500 gallon liquid capacity to provide 1-week capacity sufficient to achieve the assumed 35.7% reduction in NO_x concentration

- ammonia vaporizers to provide ammonia gas during cold weather operations (natural insolation during warmer months will provide sufficient heating to produce ammonia vapors in the storage tank)

- safety, containment and control devices as required by N.J.A.C. 7:31-2.3 and 7:26-2.10(b)(6)(ii) and (iv) to prevent ammonia system overpressurization, and to control, reduce, and contain any significant releases of ammonia that may occur as a result of system failures (these measures are currently envisioned to include safety relief valves, a containment dike system, and fogging nozzles around the liquid ammonia storage tank and delivery area).

3.2.2 Operating Experience and Applicability to MSW Incinerator

Ammonia injection has been applied to numerous petroleum heaters as well as to a limited number of utility and industrial boilers fired with natural gas or oil. Most of the existing applications are in the United States and Japan, with a few installations in Europe. Table 3-3 is a summary table of SNCR installations (Exxon, 1988). NO_X reductions ranging from 30 to 80% have been demonstrated on these units (SCAQMD). The highest NOx removal efficiency ever demonstrated, 85%, was achieved

TABLE 3-3

THERMAL DeNO$_x$ EXPERIENCE SUMMARY

	Installed	Construction Phase	Design Phase
Japanese Industrial Boilers	4		
Japanese Utility Boilers	5		
Japanese Petroleum Heaters	4		
Japanese Municipal Incinerator (Demonstration)	1		
California Oil Field Streamer (Demonstration)	1		
California Flat Glass Melting Furnace	1		
California Petroleum Heaters	30		
California Utility Boiler	1		
California Industrial Boilers	3		1
California Incinerators	1	1	1
California Oil Field Steamers (Commercial)	5		
California Wood-Fired Boilers	1		1
German Coal-Fired Utility Boilers	2		

Source: Exxon 1988

on a coal-fired utility boiler in West Germany. Though Exxon literature (Lyon, 1987).claims that 90% reductions have been achieved, further contact with Exxon shows that 85% was the absolute maximum NOx reduction achieved using Thermal DeNOx, with 80% being the maximum reduction achieved on more than one unit.

It should be noted that the majority of facilities listed in Table 3-3 fire refinery gas, natural gas, crude oil or oil. Very few of these listed facilities fire waste fuels of any type or a fuel with a highly variable nitrogen content and variable higher heating value. As discussed in more detail later, achieving and maintaining the required reaction temperature is easier for a combustion source fired with fuel of a relatively constant composition. Ammonia injection, in fact, has been applied on very few MSW incinerators. Thermal $DeNO_X$ has been in operation on only one MSW incinerator in the United States, at the Commerce Refuse-to-Energy Facility in California. The incinerator, a 300 TPD unit supplied by Foster Wheeler, has been operating with Thermal $DeNO_X$ since February 1987. The control system was designed to achieve 20-50% NO_X reductions, and was permitted as an "innovative technology" under the rules of the California South Coast Air Quality Management District at an hourly emission rate equivalent to only a 20% NO_X reduction.

Two other facilities in California have been permitted with ammonia injection. The Thermal $DeNO_X$ installation at the Long Beach (SERRF) facility was permitted to achieve 40% NO_X reductions, deemed the Lowest

Achievable Emission Rate (LAER). This facility started up on July 6, 1988; no data is available yet on Thermal $DeNO_X$ performance.

The second facility in Modesto, California, Stanislaus County, will use Thermal $DeNO_X$. This technology was deemed BACT by USEPA Region IX (Andrews 1988). The decision to install ammonia injection was not concluded to be BACT in the BACT analysis, but was proposed by Ogden Martin due to the extreme economic consideration of local agency requirements to purchase 265 tons per year of scarce NO_X emissions offsets at an estimated cost of $3-9 MM (Ogden Martin, 1988). The Stanislaus facility has just recently begun operation; stack test and process data on Thermal $DeNO_X$ performance is, therefore, unavailable. If the actual reductions are not shown to be as agreed to in the permit, additional control measures or the purchase of offsets will, nevertheless, still be required under the terms of the permit and local air quality regulations.

Thermal $DeNO_X$ has been utilized at the Commerce Refuse-to-Energy Facility for over a year and therefore is considered by USEPA to be an available NO_X control technology for MSW incinerators as stated in the Remand Order.

3.2.3 Observed Control Efficiency

In evaluating the potential control efficiency of SNCR, it is most useful to focus on the experience gained with its application to waste incineration. Two separate series of emission tests were conducted at Commerce: the facility acceptance tests in 1987, and tests during an optimization study in June, 1988.

A series of emission tests were conducted at the Commerce Refuse-to-Energy Facility between May 26 and June 5, 1987 (McDannel, et al., 1987). Included in these tests were an evaluation of NO_X emissions using a continuous emissions monitor (CEM). Five separate tests were conducted with the CEM for NO_X. These included three tests with normal ammonia injection, one test with high ammonia injection, and one test in which the ammonia injection system was shut off. All of the tests were conducted with the facility at 100% waste firing capacity. The results of these tests are presented in Table 3-4.

There was no direct measurement made of the control efficiency of the SNCR system since ammonia is injected immediately downstream of the secondary combustion zone where NO_X measurements can not be made. An estimate of the control efficiency can be made by comparing the average NO_X emission rate during ammonia injection (25.8 lb/hr) with the emission rate measured when the ammonia injection was shut off (46.5 lb/hr). This yields an apparent NO_X removal efficiency of 44.5%.

An additional test was conducted while operating at an increased rate of ammonia injection. This test produced the lowest emission rate (18.6 lb/hr) and the highest control efficiency (60%). More recent similar tests have failed to produce a similarly high estimate of control

TABLE 3-4

RESULTS OF CONTINUOUS EMISSIONS MONITOR TESTS AT COMMERCE REFUSE-TO-ENERGY FACILITY (MAY 27, 1987)

Test No. Sample Time NH_3 Injection	2-Stk-CEM 0955-1100 Nom	3-Stk-CEM 1120-1235 Nom	4-Stk-CEM 1305-1425 Nom	Avg — Nom	5-Stk-CEM 1525-1603 Off	6-Stk-CEM 1721-1750 High
O_2, %	10.8	10.6	10.2	10.5	10.0	10.2
NO_x: ppm	68	64	69	67	121	48
ppm at 3% O_2	120	112	116	116	199	80
lb/hr*	26.1	24.7	26.7	25.8	46.5	18.6
CO: ppm	12	12	11	12	11	15
ppm at 3% O_2	21	21	18	20	18	25
lb/hr*	2.8	2.8	2.6	2.7	2.6	3.5

*Determined using average flow rate from the three particulate tests.

Source: McDannel, M.D., L.A. Green, and B.L. McDonald, 1987. Air Emissions Tests at Commerce Refuse-to-Energy Facility, May 26 - June 5, 1987. Volume I: Test Results, ESA 20522-449.

efficiency. The test conducted during increased ammonia injection showed a 25% increase in CO emissions. The fact that ammonia injection causes an increase in CO emissions has been verified by other investigators (Lyon, 1987; Moilanen et al., 1987) and is believed to be due to competition for the OH radical between the NH_3 and CO species. The OH radical plays a major role in the conversion of CO to CO_2. Therefore, if more of it is captured by NH_3 being injected, less of the CO in the combustion gases will be converted to CO_2.

A more recent set of measurements of NO_X was taken in June, 1988 at Commerce. The purpose of this study was to optimize use of the SNCR system (McDannel and McDonald, 1988a). A total of 32 separate tests were made for different combinations of NH_3 injection location, NH_3 injection rate, and carrier air pressure.

Table 3-5 presents the results of the optimization study when the top row of injection nozzles was used. Table 3-6 presents the test results using the bottom row of injection nozzles. A comparison of top vs. bottom row effectiveness was made by the Commerce testing team after the first twelve tests of the program, and the conclusion was made that the top row of nozzles was significantly more effective in controlling NO_X. Subsequent testing at the facility to evaluate carrier air flow, NH_3 rate and data repeatability were performed using the top injection row only.

Tables 3-5 and 3-6 also show that the percent reduction in NO_X is not consistent and varies from as low as 11 percent to 61 percent. The

TABLE 3-5

RESULTS OF THERMAL DeNO$_x$ EVALUATION TESTS - TOP INJECTION ROW

Test No.	Injection Level	NH$_3$ Rate, lb/hr	Mole Ratio, mole NH$_3$/ mole NO$_x$	Carrier air flow scfm	Carrier air pressure psig	Stack O$_2$, %	Baseline NOx, ppm @ 3% O$_2$	NOx, ppm @ 3% O$_2$	% NOx Reduction
55	Top	15	0.68	120	0	10.6	256	187	27.0
23	Top	15	0.95	730	20	9.8	184	135	26.4
36	Top	15	0.86	740	20	9.6	173	138	20.2
24	Top	15	0.92	800	30	9.8	186	159	14.5
35	Top	15	0.82	880	30	9.1	177	136	23.2
53	Top	30	1.43	120	0	10.4	240	135	43.8
51	Top	30	1.32	140	1	10.0	236	138	41.5
47	Top	30	1.38	310	2	10.2	245	137	44.1
50	Top	30	1.57	320	2	10.2	205	87	57.5
21	Top	30	1.98	730	20	10.6	165	81	50.9
33	Top	30	1.73	750	20	10.5	193	105	45.6
22	Top	30	1.74	800	30	10.4	187	96	48.7
52	Top	30	1.27	850	30	9.0	201	132	34.3
45	Top	30	1.18	850	30	10.3	281	138	50.9
34	Top	30	1.70	870	30	9.0	176	137	21.9
54	Top	45	2.06	120	0	10.7	246	126	48.8
47	Top	45	2.14	310	2	9.9	221	111	49.8
41	Top	45	2.27	530	8	9.5	212	152	28.3
42	Top	45	2.35	530	8	10.2	216	135	37.5
39	Top	45	2.70	530	8	9.4	178	146	18.0
20	Top	45	2.85	730	20	10.5	182	83	54.4
32	Top	45	2.44	750	20	10.5	213	108	49.3
19	Top	45	2.55	800	30	8.9	192	75	60.9
46	Top	45	2.09	810	30	10.3	242	190	21.3
31	Top	45	2.71	850	30	10.7	195	90	53.8
44	Top	45	1.79	880	30	10.3	269	102	62.0

Source: McDannel and McDonald, 1988b

TABLE 3-6

RESULTS OF THERMAL DeNO$_x$ EVALUATION TESTS - BOTTOM INJECTION ROW

Test No.	Injection Level	NH$_3$ Rate, lb/hr	Mole Ratio, mole NH$_3$/mole NO$_x$	Carrier air flow scfm	Carrier air pressure psig	Stack O$_2$, %	Baseline NOx, ppm @ 3% O$_2$	NOx, ppm @ 3% O$_2$	% NOx Reduction
30	Bottom	15	0.85	680	20	9.9	200	175	12.5
27	Bottom	15	0.92	710	30	9.4	169	150	11.0
29	Bottom	30	1.99	670	20	10.7	213	161	24.4
26	Bottom	30	1.77	710	30	8.9	174	147	15.3
28	Bottom	45	2.26	670	20	10.5	215	138	35.7
25	Bottom	45	2.46	730	30	10.6	200	103	48.4

Source: McDannel and McDonald, 1988b

variance is due to several factors, including the location of the nozzles and the amount of NH_3 that is injected in excess of the stoichiometric ratio of NH_3 to NO_X.

The impact of carrier air flow was also assessed in the optimization study. Carrier air is used in the Thermal $DeNO_X$ system to assist in carrying NH_3 from the NH_3 storage tank to the boiler, and to provide increased volumetric flow, and thus increased jet velocities at the injection nozzles. Increased jet velocities are intended to improve penetration and mixing of NH_3 with the furnace exhaust gases (McDannel and McDonald, 1988a). The optimization study evaluated air compressor outlet pressures at 0, 1, 2, 8, 20 and 30 psig. Table 3-7 shows the relationship of carrier air pressure and injection location to NO_X reductions.

Results from the optimization study yielded important conclusions regarding the role of carrier air pressure. The first conclusion was that mixing of NH_3 and furnace gas is adequate for high NO_X reduction efficiency at low or nonexistent carrier air pressure. The second conclusion was that for purposes of testing programs, carrier air pressure is not a test variable that needs to be considered when evaluating the impact of other parameters on system performance.

Besides nozzle location and carrier air pressure, the optimization study also focused on the relationship between the molar injection ratio of NH_3 to uncontrolled NO_X and the effectiveness of NO_X reduction. These

TABLE 3-7

RELATIONSHIP OF CARRIER AIR PRESSURE AND INJECTION LOCATION TO NO_X REDUCTIONS AT THE COMMERCE WASTE-TO-ENERGY FACILITY

Injection Location	NH_3 Rate (lb/hr)	Carrier Air Pressure (psig)	No. of Tests	NO_x Reduction (%)		
				Avg.	High	Low
Top	15	0	1	27.0	-	-
Top	15	20	2	23.3	26.4	20.2
Top	15	30	2	18.9	23.2	14.5
Top	30	0	1	43.8	-	-
Top	30	1	1	41.5	-	-
Top	30	2	2	50.8	57.5	44.1
Top	30	20	2	48.3	50.9	45.6
Top	30	30	4	39.0	50.9	21.9
Top	45	0	1	48.8	-	-
Top	45	2	1	49.8	-	-
Top	45	8	3	27.9	37.5	18.0
Top	45	20	2	51.9	54.4	49.3
Top	45	30	4	49.5	60.9	21.3
Bottom	15	20	1	12.5	-	-
Bottom	15	30	1	11.0	-	-
Bottom	30	20	1	24.4	-	-
Bottom	30	30	1	15.3	-	-
Bottom	45	20	1	35.7	-	-
Bottom	45	30	1	48.4	-	-

Source: McDannel and McDonald, 1988b.

impacts are illustrated in Figures 3-1 and 3-2 for testing with the top injection row.

These figures show that there is a great deal of scatter in the data, which is due to the highly variable nature of combustion in an MSW incinerator. Fuel composition is a major combustion variable that is basically uncontrollable. The optimization study also theorized that additional scatter in NO_X reduction data may be also due to temporal and spatial variations in such items as flue gas temperature and velocity, which vary significantly during normal operation (McDannel and McDonald, 1988a).

As a result of these continuously changing conditions, scatter in the test data is inevitable. For example, Table 3-7 shows that although average NO_X reductions of 39.0% were achieved when operating the top row of injection nozzles at an ammonia injection rate of 30 lb/hr and a carrier air pressure of 30 psig, the NO_X reductions actually varied from 21.9% to 50.9% over 4 test runs.

Besides showing data scatter, results from the optimization study also indicated the relative stoichiometric molar ratios required to achieve the highest NO_X reductions. Figures 3-1 and 3-2 show that for the top row of injection nozzles, NO_X removal efficiency increases sharply with NH_3 injection rate at low rates, and then levels off at mole ratios between 1.6 and 2.0.

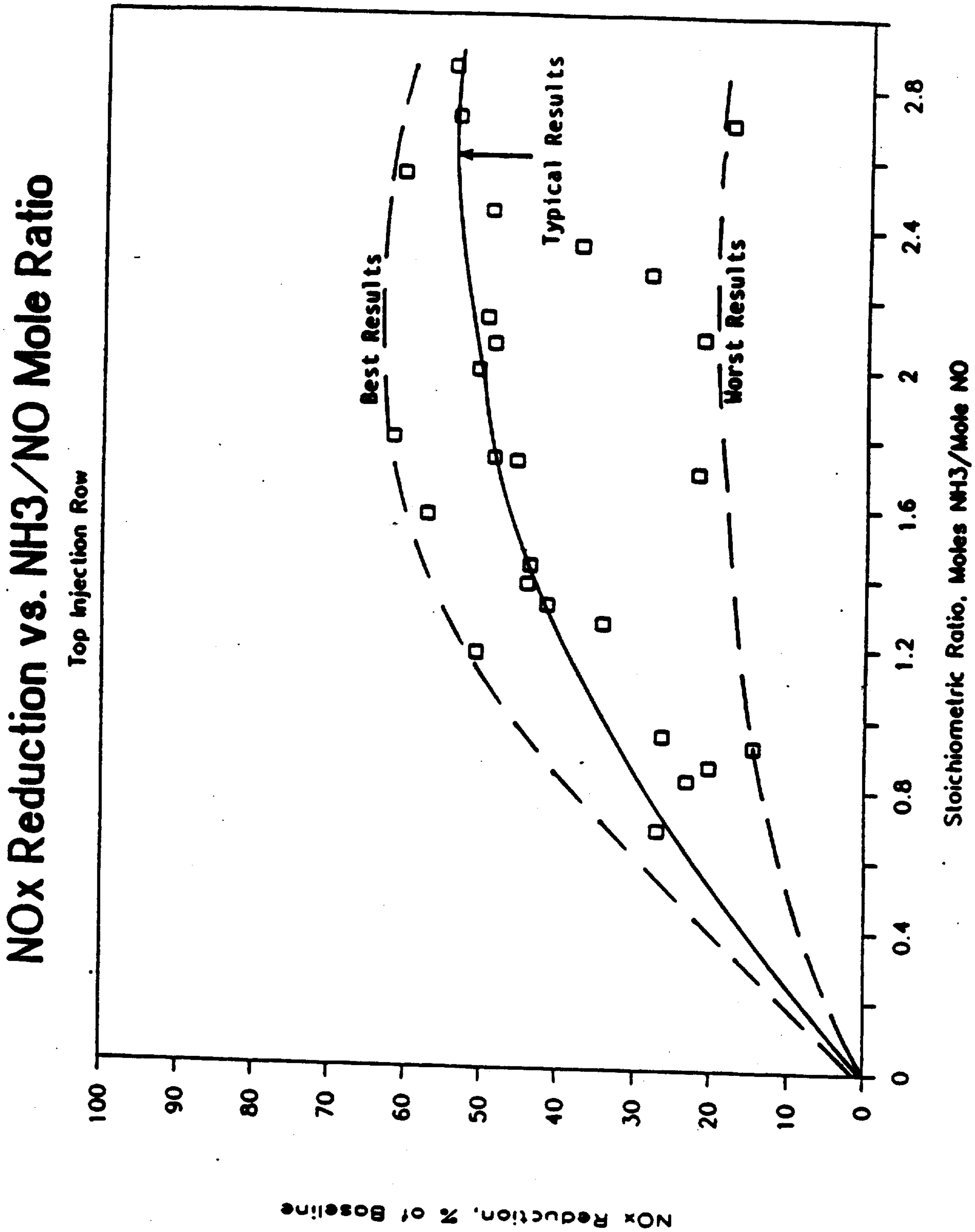

Figure 3-1. NOx reduction vs. NH3/NO mole ratio.

Source: McDannel and McDonald, 1988b

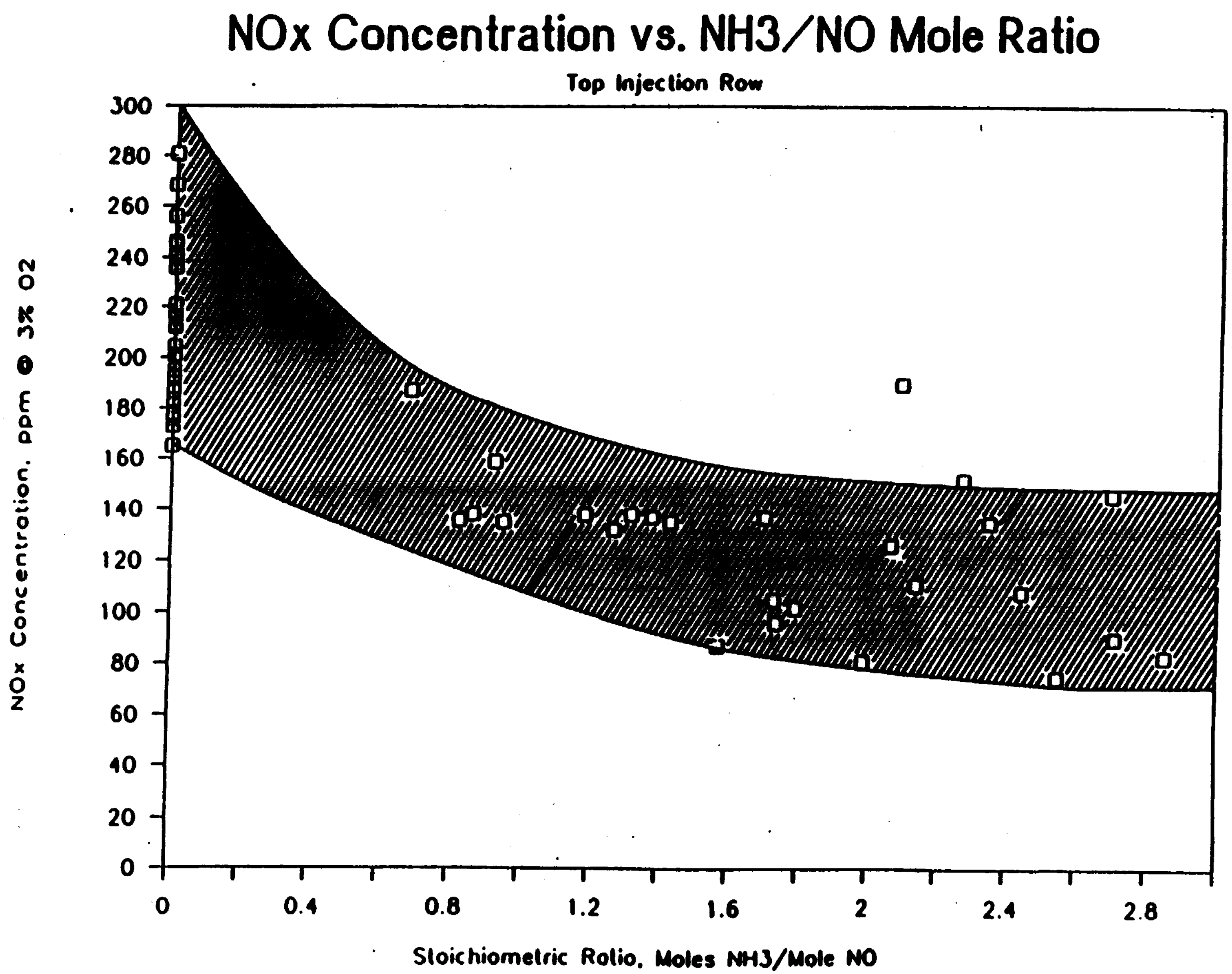

Figure 3-2. NOx concentration vs. NH3/NO mole ratio.

Source: McDannel and McDonald, 1988b

The optimization study concluded, based on the data shown in Table 3-8, that the optimum balance between NO_X reduction and molar ratio of NH_3 injection is achieved by using the top injection row at an injection rate of 30 lb/hr (NH_3/NO_X mole ratio of 1.5), but that use of a higher ammonia injection rate, 45 lb/hr (mole ratio of 2.5) provided removal at an average removal efficiency marginally greater than at the lower mole ratio.

However, when comparing tests run at 30 and 45 lb/hr injection rates for the same carrier air pressure (refer to Table 3-7) the runs at 45 lb/hr usually achieved greater NOx removals. In addition, the two highest removal efficiencies observed in the testing program were achieved using 45 lb/hr of ammonia, and 30 psig air pressure (refer to Table 3-5). Therefore, because of the different means by which the effects of stoichiometry on NO_X reduction may be summarized, it is more appropriate to conclude that stoichiometric molar ratios of 1.6 to 2.5 are necessary to achieve the highest NO_X reductions.

To further complicate the analysis, results from the optimization study also indicate that the higher stoichiometric ratios do not always yield the highest NO_X removal rates. As shown on Table 3-5, at a stoichiometric molar ratio of 2.09 (45 lb/hr), the NO_X reduction was only 21.3%, and at a molar ratio of 2.70 (also 45 lb/hr), the NO_X reduction was only 18%.

Clearly the scatter in data and the resulting inability to develop absolute correlations to predict Thermal DeNO$_X$ performance require that the NO$_X$ reduction guarantee for permitting purposes be cautiously selected. Table 3-8 summarized the measured NO$_X$ reduction under a range of NH$_3$ injection rates. Under typical operating conditions (i.e., 30 lb/hr injection rate) the average NO$_X$ reduction is 44% with a standard deviation of 10%. This indicates that 67% of the time the NO$_X$ control should be between 35% and 54%. This is an important factor to consider if three-hour not-to-exceed emission limits for NO$_X$ are to be based on use of an ammonia injection system.

In this regard, Ogden Martin has conducted their own analysis of Thermal DeNO$_X$ and has concluded that a guaranteeable NO$_X$ control efficiency on a continuous basis is 35.7%, based on an uncontrolled NOx emission concentration in the flue gas of 350 ppmdv @ 7% O$_2$ and a controlled emission concentration of 225 ppmdv @ 7% O$_2$. Therefore, 35.7% control efficiency is deemed the second most stringent control level for the BACT analysis, based on technical feasibility. This control efficiency was used in subsequent assessment of economic, environmental and energy impacts because it represents a guaranteed, not an assumed or theoretical, level of control.

3.2.4 Advantages of Ammonia Injection

Technical Advantages

An ammonia injection system is a simple system including an ammonia

TABLE 3-8

SUMMARY OF NO_x REDUCTIONS AT THE COMMERCE WASTE-TO-ENERGY FACILITY

Injection Location	NH_3 rate (lb/hr)	Average Mole Ratio (NH_3:NO_x)	No. of Tests	NO_x Reduction (%)			
				Avg.	High	Low	S.D.*
Top Row	15	0.85	5	22.3	27.0	14.5	5.1
	30	1.53	10	43.9	57.5	21.9	9.9
	45	2.36	11	44.0	62.0	18.0	15.4
Bottom Row	15	0.89	2	11.8	12.5	11.0	1.1
	30	1.88	2	19.8	24.4	15.3	6.4
	45	2.36	2	42.1	48.4	35.7	9.0

*S.D. - standard deviation

Source: McDannel and McDonald, 1988b.

storage tank, piping, instrumentation, compressors and injection nozzles. Designing the system, however, for proper nozzle location and ammonia injection rate, taking into account fuel variability, temperature profile and other factors, incurs greater expenses.

Economic Impacts

The capital and operating costs of ammonia injection systems are generally lower than those of SCR and control systems for other pollutants. The estimated capital cost of the DeNO$_x$ System is about 46% of that for SCR; operating costs of Exxon's system are 17 to 20% of those for SCR. As indicated earlier, the SCR economic analysis did not incorporate costs associated with safety equipment, therefore, the capital cost of the DeNO$_x$ system is less than 46% of SCR presented above.

Environmental Impacts

Ammonia injection at 35.7% efficiency is the second-best means by which to reduce NO$_X$ emissions, as demonstrated at an existing MSW incinerator. At this level of control, annual ambient NO$_X$ impacts from the proposed Pennsauken Resource Recovery Facility would decrease from 0.41 ug/m^3, calculated in the original modeling analysis presented in the FEHIS, to 0.26 ug/m^3 at the point of maximum impact. This impact is small, however, compared to existing NO$_X$ concentrations of 62 ug/m^3 and to the annual air quality standard of 100 ug/m^3.

In addition, it has been theorized that ammonia injection may be responsible for a decrease in dioxin emissions, though this has yet to be thoroughly researched and proven. The NJDEP (Atay, 1988) has learned of research showing that copper in flyash may act as a catalyst for dioxin formation, and that NH_3 present in the flue gas may act as a catalyst "poison", thereby inhibiting dioxin formation. Ogden Martin is not aware of any other research supporting this theory, however.

Finally, the system requires no water use, and does not produce a liquid or solid waste.

3.2.5 Disadvantages of Ammonia Injection

Technical Disadvantages

The guarantees provided by SNCR vendors are limited, and do not provide the applicants assurance that the system will work over long periods of time. Though Exxon typically guarantees meeting a specified removal efficiency during compliance tests, long-term compliance is solely the responsibility of the owner. In fact, Exxon's financial liability for redesign and other costs is only about 50% of the royalty, equalling for this project only about $48,000.

Another technical disadvantage with the system is that all process details, kinetic equations and other design information are all proprietary information of Exxon, the licensor of the technology design.

Only Exxon has knowledge of the 31 kinetic equations and the impacts of various flue gas constituents on performance. This information is neither published nor divulged to Exxon's clients, such that the major responsibility in designing and optimizing the system rests with Exxon and not the incinerator designer who is the permittee or -- as in Ogden Martin's case in the Pennsauken facility -- bound to perform in compliance with permit conditions by contractual guarantees.

Another disadvantage is that designing for, achieving and maintaining the required reaction temperature is difficult. As shown by operating experience, refuse-fired incinerators have highly dynamic temperature profiles. The furnace gas temperature is a function of refuse composition, unit design, operation and load. The refuse composition, which determines the combustion quality and the higher heating value of the refuse, is affected by numerous variables, such as the source of the refuse, the season of collection, the time of day, and the degree to which the refuse is mixed by the operator. The unit design and operation dictate refuse distribution, combustion air quantity and distribution, flue gas residence time, and levels of turbulence. In addition, operating at part-loads affects the temperature profile within the boiler, flue gas flowrates and associated flue gas mixing patterns.

Therefore, while sophisticated computer reaction kinetic models may be employed to design an optimum system, and supplementary fuel-firing and multiple injection ports be used to facilitate achieving desired temperatures and NH_3/NO mixing, controlling the temperature in applications with refuse, a fuel of highly variable composition and heating value, is difficult. The necessary temperature window is always shifting as a result of the heterogeneous nature of MSW and the reaction of the Martin Control System to these variable combustion conditions. Therefore, the optimization and resultant operating efficiency of the Thermal DeNO$_X$ process is more strongly dependent on these operating parameters than the models available to design this system. Other pollution control equipment used in resource recovery plants are placed well downstream of the combustion zone so that effects of MSW variability on operation and performance are not pronounced.

There have been very limited studies analyzing DeNO$_X$ technology installed on waste-to-energy facilities to monitor its performance, adjust the system, and look for correlations between performance, combustion conditions and operating variables. The resource recovery facility in Commerce, California has the only operating MSW incinerator in the nation equipped with Thermal DeNO$_X$. That system has undergone major changes and extensive study, indicating that the technology is still being developed.

The Commerce facility initially experienced problems with Thermal DeNO$_X$ performance resulting from operation/maintenance problems within the combustion unit itself (Exxon, 1988). These problems, which were caused by inaccurately estimating the design waste's higher heating value (HHV) created a need for operation at reduced excess air, thereby resulting in greater furnace temperatures. Because of the higher temperature and associated decrease in DeNO$_X$ capability, the NH$_3$ injectors had to be relocated and tested to accommodate the new temperature profile within the boiler.

The optimization study performed in 1988 at the Commerce facility also demonstrated that though Thermal DeNO$_X$ reduces NO$_X$, further research will be needed in order to predict system performance with certainty. This is important since the NJDEP establishes permit emission limits in terms of three-hour not-to-exceed emission values. The Commerce data showed extreme variability in control efficiencies, even after locating the injection nozzles in the "optimal" location, indicative of the fact that reliable and sustainable control of NO$_X$ emissions with SNCR has not been adequately demonstrated. The uncertainties with NO$_X$ control efficiencies and the highly variable uncontrolled NO$_X$ emission rate discourage meeting stringent, not-to-exceed one hour NO$_X$ permit emission limits.

Another disadvantage is that no long-term operating data on the technology's application to MSW incineration is available. The air permits in New Jersey are valid for 5 years, meaning that all permit limits must be met throughout the period. There simply are no SNCR operating data collected over long enough period at an MSW-incinerator to indicate if, and how well, these long-term permit limitations would be met.

A final disadvantage is corrosion. Heck, et al., (1987) observed that ammonium bisulfate and related compounds may form at temperatures below 572°F. Therefore, potential areas subject to this corrosion would include the economizer, the air pollution control equipment and stack, all of which operate below this temperature. These salts could be responsible for fouling heat transfer surfaces with corrosive deposits, resulting in increased maintenance and poor heat transfer (i.e. reduced energy recovery). Severe corrosion problems were experienced at the Commerce facility requiring boiler tube replacement and downtime. It is not known, however, whether the ammonia salt formation caused the corrosion.

NH_3 Slip CEM Requirement

Because operation of SNCR produces an emission of unreacted NH_3 which is both a potential source of visible emissions and an indicator of operating efficiency, NJDEP will require that continuous emission monitors (CEM) be provided for NH_3 on both combustion units.

The measurement of ammonia (NH_3) by CEM is a new application of CEM technology used in other industrial applications. Several designs are available in the marketplace, however, the only known waste to energy facility in North America with NH_3 CEM is the SERRF project in California. This system is presently in the start-up phase coincident with facility start-up.

The SERRF NH_3 CEM system is the reference system in this evaluation regarding equipment requirements, cost estimates and operating experience. The system was supplied as a process control element integral to the thermal $DeNO_X$ system and is used to determine the concentration of ammonia slip present in the stack exhaust.

The SERRF Facility uses an extractive-type CEM system with NH_3 analysis being an integral feature of the system. A heated sample probe and transport sample line are used to obtain and transport a flue gas sample to the analyzer cabinet provided for the entire CEM system. The NH_3 sample analysis is conducted as a component of all the total analysis including data processing and recording. If the system procured to monitor other pollutants required by permit conditions is not an extractive design, then the analysis must be provided as an independent, dedicated system.

The analytical technique used to determine NH_3 concentrations uses a catalytic reaction chamber to reduce all NH_3 in the gas to NO. The NO created is, thus, in addition to the NO_2 normally present in the flue gas. Therefore, two analyzer lines are required to determine the concentration of ammonia. The primary line is defined as the equipment required to determine the concentration of the "normal" NO_X (as NO_2) in the flue gas. The secondary line includes the catalytic converter where NH_3 is oxidized to NO_2 and a second NO_X analyzer where the total NO_X concentration is determined. The concentration of ammonia is determined by the difference between the result from the primary and secondary NO_X analyzers.

A dedicated NH_3 CEM system requires a special heated sample probe, sample conditioner, enclosure modifications, catalytic reactor with heater control, NO_X analyzer, software programming and system engineering. This add-on approach requires an additional expenditure of approximately $150,000 per flue.

An additional O&M labor cost is required for the NH_3 analysis system. This includes maintenance and repair of the equipment, bi-annual replacement of the reaction catalysts - which are estimated to have a life span of 6 months - and costs of heating the needed sample extractors and transport lines. These costs are not included in this analysis.

Economic Impacts

Table 3-9 details the capital cost components in terms of Engineering Equipment, Bulk Commodities/Construction Labor and Engineering and Other Costs. The costs of individual Engineered Equipment, Bulk Commodities and Construction Labor are based on both Ogden Martin experience and tabulation of actual costs for the installation of an ammonia injection system at the Stanislaus County facility in California. Additional costs have been estimated for safety design features required for ammonia storage.

The Design Engineering estimate of $225,000 is based on actual costs for engineering required for the Thermal $DeNO_X$ installation at the Stanislaus County facility. The estimate includes fees for outside

TABLE 3-9

CAPITAL COSTS OF AMMONIA INJECTION FOR THE PENNSAUKEN FACILITY*(1)

	Capital Costs (1988 Dollars)
1. Engineered Equipment:	
o Ammonia injection headers and nozzles	$107,000
o Ammonia circulation heaters	8,000
o Air compressors	158,000
o Ammonia storage tank	25,000
o Electrical equipment	32,000
o Instrumentation and controls	156,000
o Ammonia Slip CEM	300,000
Total Engineered Equipment	$786,000
2. Bulk Commodities and Construction Labor:	
o Earthwork and concrete	$ 69,000
o Structural steel and buildings	60,000
o Piping including valving and supports	179,000
o Electrical and controls	150,000
o Painting	5,000
o Equipment erection	38,000
o Construction management, indirects & fees	85,000
Total Bulk Commodities and Construction	$586,000

TABLE 3-9

CAPITAL COSTS OF AMMONIA INJECTION FOR THE PENNSAUKEN FACILITY*(1)
(continued)

3. Engineering and Other Costs:	
o Design engineering	$225,000
o Exxon engineering	100,000
o Exxon licensing fee	96,000
o Risk/contingency	242,000
o S.A. & G.	265,000
Total Engineering and Other Costs	$928,000
Subtotal Installed/Capital Cost	$2,300,000
4. Safety Design Features (2)	$ 300,000
Total	$2,600,000

*Based on achieving a design outlet concentration of 225 ppm, representing 35.7% control.

Notes: (1) Ogden Martin (1988)
(2) As described on Page 77 of this report

architect/engineering services and for internal engineering at Ogden Martin. These estimates include payroll costs for engineering, project management, and engineering support services, as well as related non-payroll costs. The Exxon Research & Engineering fee of $100,000 was estimated based upon information received from Exxon in the past, adjusted to present day conditions. Exxon charges a fee for the process engineering performed by Exxon for their proprietary system. The Exxon Licensing Fee of $96,000 was calculated based upon previous quotes obtained from Exxon for other projects. Contingency, estimated at $242,000, was calculated by Ogden Martin through an analysis of potential "soft areas" and risks associated with the system. The $265,000 charge for Sales, Administration and General costs, which is over and above the engineering fee, includes Ogden Martins' material overhead costs and the cost of system start-up.

The annualized capital and operating charges are summarized in Table 3-10 for the Thermal DeNO$_X$ system, as depicted in Figure 3-3. Again, these cost data were calculated using cost data and material consumption rates previously supplied by Exxon in the preliminary cost quote, and by unit costs researched by Ogden Martin and ENSR. Ammonia consumption rates, however, were refined based on findings in the optimization study performed at the Commerce Refuse-to-Energy Facility in California. The results from that study showed that the stoichiometric molar ratios of NH_3 to NO_X required to achieve optimum performance are between 1.6 and 2.5.

Calculations and assumptions supporting several of the individual costs in Table 3-10 are included in the notes at the bottom of that table. The boiler/economizer corrosion cost of $55,000 is directly associated with Thermal DeNO$_X$ technology: the formation of ammonia salts can lead to precipitation of highly acidic droplets, which, over long periods of time, will invariably lead to boiler fouling. The boiler tubes will thus have to be cleaned more frequently than is the case without SNCR, requiring intermittent plant shutdowns. Should fouling persist, the corrosive salts could damage the boiler economizer tubes, possibly requiring replacement of entire sections. Labor, maintenance and refurbishment charges of $105,000 were estimated by Ogden Martin based on projections at the Stanislaus County Facility. Overhead charges of $60,000 represent charges for general in-house services, equipment, outside services not furnished directly by Ogden, any unusual items of expense not incurred in normal operations, printing, long distance communication charges, shipping charges, miscellaneous suppliers and rentals.

The sum of these operating costs, as shown in Table 3-10, ranges from $359,400 to $450,100. Ammonia consumption accounts for the largest percentage of these operating costs, at 22 to 37%.

Annualized costs include capital recovery and operating/maintenance charges. Capital recovery, which accounts for depreciation, may be estimated by multiplying the capital recovery factor (CRF), 0.1095, by the Total Installed Capital Cost, $2,600,000. Capital recovery charges are $284,700/yr. Operation costs range from $359,400 to $450,100.

TABLE 3-10

ANNUALIZED CAPITAL AND OPERATING COSTS OF AMMONIA INJECTION

Operation Costs:

Ammonia Consumption(1)	\$ 80,200 - 168,000
Air Compressor Electrical Cost(2)	54,000
Ammonia Electrical Heating Cost(3)	5,200 - 8,100
Boiler/Economizer Corrosion	55,000
Labor, Maintenance, Refurbishment	105,000
Overhead	60,000
Subtotal	\$359,400 - 450,100

Annualized Costs:

Capital Recovery Charges	\$284,700
Operation Costs	359,400 - 450,100
Total Annual Operating Cost:	\$644,100 - 734,800
Ton NO_X Removed Per Year(4)	162
Cost Effectiveness	\$3,980/ton to \$4,540/ton

Notes:

(1) Ammonia consumption and cost

Uncontrolled NO_X emissions: 103.7 lb/hr
Molar Ratio (NH_3/NO_X) required: 1.6 to 2.5
Molecular weight (MW) of NH_3: 17 lb/lb mole
NO_X: 46 lb/lb mole

Low NH_3 consumption rate:

$$1.6 \frac{\text{lb mol } NH_3}{\text{lb mol } NO_2} \times \frac{\text{lb mol } NO_2}{46 \text{ lb } NO_2} \times 103.7 \frac{\text{lb } NO_2}{\text{hr}} \times \frac{17 \text{ lb}}{\text{lb mol } NH_3} NH_3 = 61 \frac{\text{lb } NH_3}{\text{hr}}$$

High NH_3 Consumption Rate:

$$61 \frac{\text{lb}}{\text{hr}} NH_3 \times \frac{2.5}{1.6} = 96 \frac{\text{lb}}{\text{hr}} NH_3$$

Cost range of NH_3:

Unit cost @ $\frac{\$300}{\text{ton}} - \frac{\$400}{\text{ton}}$

TABLE 3-10
ANNUALIZED CAPITAL AND OPERATING COSTS OF AMMONIA INJECTION
(continued)

Lower Cost: $\frac{\$300}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times 61\ \frac{\text{lb}}{\text{hr}}\ NH_3 \times \frac{8760}{\text{yr}}\ \text{hr} = \frac{\$80,200}{\text{yr}}$

Upper Cost: $\frac{\$400}{\text{ton}} \times \frac{\text{ton}}{2000\ \text{lb}} \times 96\ \frac{\text{lb}}{\text{hr}}\ NH_3 \times \frac{8760}{\text{yr}}\ \text{hr} = \frac{\$168,000}{\text{yr}}$

(2) Air Compressor Electrical Cost

Unit Costs: 0.0018 kw. hr/scf (Source: Stanislaus Facility)
$0.06/kw. hr

$$0.0018\ \frac{\text{kw. hr}}{\text{scf}} \times \frac{\$0.06}{\text{kw. hr}} = \frac{\$0.00011}{\text{scf}}$$

Compressor Requirements: Prorating the Hudson facility compressor requirements of 1690 SCFM, the Pennsauken Facility will require 470 SCFM.

Compressed Air Cost:

$$470\ \frac{\text{scf}}{\text{min}} \times 2 \times 60\ \frac{\text{min}}{\text{hr}} \times 8760\ \frac{\text{hr}}{\text{yr}} \times \frac{\$0.00011}{\text{scf}} = \frac{\$54,000}{\text{yr}}$$

(3) Ammonia Electrical Heating Cost:

Exxon's quote for the Hudson facility provided data to calculate unit ammonia heating cost:

$$54,000\ \frac{\text{Btu}}{\text{hr}} \times \frac{\text{hr}}{97\ \text{lb}\ NH_3} = 556.7\ \frac{\text{Btu}}{\text{lb}\ NH_3}$$

Applying that ratio to ammonia consumption rate calculated in (1) above:

Lower Heating Cost:

$$556.7\ \frac{\text{Btu}}{\text{lb}\ NH_3} \times 61\ \frac{\text{lb}\ NH_3}{\text{hr}} \times 8760\ \frac{\text{hr}}{\text{yr}} \times \frac{\text{kw. hr}}{3414.7\ \text{Btu}} \times \frac{\$0.06}{\text{kw. hr}} = \frac{\$5,200}{\text{yr}}$$

Higher Heating Cost:

$$\$5,200 \times \frac{2.5}{1.6} = \frac{\$8,100}{\text{yr}}$$

(4) NO_X controlled @ 35.7% efficiency

$$103.7\ \frac{\text{lb}}{\text{hr}}\ NH_3 \times 0.357 \times \frac{\text{ton}}{2000\ \text{lb}} \times 8760\ \frac{\text{hr}}{\text{yr}} = 162\ \text{tpy}$$

Total annual operating costs range from $644,100 to $734,800, with approximately 40% attributed to operation costs, and approximately 60% attributed to annualized costs.

The cost effectiveness of the 35.7% efficient system, which controls 162 tons of NO_X annually, varies from $3,980 to $4,540 per ton of NO_X controlled. These reduction costs far exceed both the traditional cut-off level of $1,250 per ton contorlled which EPA has historically used in determining whether or not a particular technology was sufficiently cost-effective to qualify as BACT on a case-by-case basis. These values also are well in excess of USEPA's "rule-of-thumb" level of approximatley $1,500 per ton controlled used to judge whether new NSPS or other requirements are reasonably cost effective.

Energy Impacts

Operating an ammonia injection system requires use of electrical energy to vaporize ammonia (10 to 15 kwh) and compress carrier gas (102 kwh). The total energy impact ranges from 112 to 117 kwh, which, at 8760 hours per year of operation and 162 tpy of controlled NO_X, translates to an energy penalty of approximately 21 MMBtu per ton NO_X controlled. This energy use will decrease the total electrical energy available for export and sale, and is not considered a reasonable energy penalty.

Environmental Impacts

SNCR does not pose some of the negative environmental impacts of SCR, namely catalyst disposal and formation of secondary pollutant emissions, including NO_X, caused by flue gas reheat. There are several potential adverse environmental impacts, however, associated with the use of SNCR, related to (1) the effects of residual ammonia in the flue gas ("ammonia slip") and a resultant visible plume, (2) possible increases in CO emissions, and (3) safety related issues due to ammonia storage.

Stack concentrations of residual ammonia will be less than 50 ppmdv and are associated with the variable rate of ammonia injection. The quantity of ammonia to be injected is not constant due to variability in fuel, operation techniques and NO_X formation. Significant levels of NH_3 may occur and be ultimately responsible for nuisance odors and the formation of ammonium salts. The estimated ground level concentration of 1.5 ug/m^3 would be well below the threshold limit value (TLV) of 18 mg/m^3 established by the American Conference of Governmental Industrial Hygienists. Although TLV's are intended as guidelines in the practice of industrial health and safety are not specifically intended to evaluate public health effects, the calculated margin of safety of 1200 in this instance is well below acceptable standards of protection.

Residual NH_3 may react with sulfuric acid (H_2SO_4) and hydrochloric acid (HCl) to form ammonium salts. Ammonium sulfate ($(NH_4)_2SO_4$)), ammonium bisulfite (NH_4HSO_4) and ammonium chloride (NH_4Cl) are the three salts formed. Ammonium sulfate and ammonium bisulfate are undesirable since they can foul low temperature heat exchange equipment.

Ammonium chloride is a dry, neutral pH, white salt which forms at low temperatures (below 250°F). Therefore, this salt can form a disconnected visible plume at some point shortly downstream of the facility after the flue gases have cooled to this temperature and exceed regional opacity requirements. Visible NH_4Cl plumes have been reported at the Kawasaki refuse combustion facility in Japan, which is equipped with ammonia injection. Though 60% NO_X reduction was being achieved at the facility, a plume was visible for about 5 miles (CDM, 1987). It should be noted that this facility was equipped with the older grid in system, such that higher ammonia consumption and poorer ammonia/air contact may have caused higher levels of ammonia slip. Commerce has not experienced these plumes; winter operation in other areas of the country besides southern California could result in plume formation, however.

Ammonium sulfate, a dry ammonium salt with a neutral pH, does not contribute to visible plume formation or fouling. Ammonium bisulfite on the other hand, can contribute significantly to fouling and corrosion in low temperature heat recovery equipment and may possibly reduce the effectiveness of acid gas and particulate control equipment. NH_4HSO_4 is acidic, hygroscopic and has a relatively low melting point (as low as 266°F). The salt can precipitate from the vapor phase as highly acidic, sticky droplets, and crystallize, plugging tubes and restricting gas flow.

Though the ammonium sulfates can be removed easily from heat recovery equipment, the cleaning would require boiler shutdown. The way to avoid shutdowns is to reduce the amount of ammonia slip. Reducing ammonia slip may be offset, however, by reduced NO_X removal efficiencies.

Ammonium salt formation in conventional combustion applications may increase particulate emissions, especially PM10 emissions, because of the size of the ammonium sulfate particles (1-3 um). ESA (1986) has reported a 145% increase in submicron (<1 um) emissions and a 330% increase in the emissions of particles smaller than 5 microns during testing of Thermal DeNO$_X$ on an oil-fired boiler in California. Test performed at the Commerce, California MSW incinerator equipped with Thermal DeNO$_X$ indicated that an average, over 2 tests, of 30% of total particulate is PM$_{10}$, but these results are not definitive because the quantities of particulate collected in the sample were at or below normal detection limits for this test method.

Ammonia is an odorous compound. Kirk-Othmer's Encyclopedia of Chemical Substances shows that ammonia is first perceptible at 20 ppm; another source lists the odor threshold as 46.8 ppmv (Cheresiminoff, 1975). Ammonia slip concentrations in the stack for the proposed type of applications could be up to 50 ppm as estimated for the Commerce facility by McDannel & McDonald for ammonia-NO$_X$ mole ratios of 2.5. Ground level concentrations, however, will be much lower because of ambient air dilution, such that odors should not be detected. No odor complaints have been lodged against the Commerce facility. It is interesting to note, however, that several odor complaints have been lodged in California by residents living near gas turbine applications equipped with selective catalytic reduction (Fogman, 1988), a NO$_X$ control technique which should emit less ammonia slip than Thermal DeNO$_X$.

Ammonia injection has been theorized to increase CO emissions, as observed during recent testing at the Commerce Refuse-to-Energy Facility in California (McDannel, et al., 1987), at a wood-fired boiler employing SCR in Long Beach, California (Moilanen, et al., 1987), and a coal-fired circulating fluidized bed (Hiltunen and Tang).

The use of Thermal DeNO$_X$ does present safety issues. The hazards of ammonia storage, handling and transportation are similar to those of SCR, as described in Section 3.1.5.

An additional adverse impact associated with SNCR is the onsite storage of anhydrous ammonia. Ammonia is a designated "Extraordinarily Hazardous Substance" or EHS as set forth in Table I of N.J.A.C. 7:32-2.3, under the New Jersey Toxic Castrophe Prevention Act Program and under the Federal SARA Title III requirements set out in the Federal Regisitor, 52 FR 13397, April 22, 1987. The quantity of on-site ammonia storage required for the SCNR process, approximately 4,500 gal (23,400 lbs.) is above the NJDEP registration quantity for this chemical. This quantity exceeds the t~~o~~wo pound threshold for emergency planning and the 100 pound threshold for reportable quantities under the Federal program. the values for ammonia are indictitive that ammonia is especially hazardous since the quantities tht trigger SARA reporting requirements range upward to 10,000 pounds.

Therefore, the Pennsauken RRF would need to comply with the requirements of the TCPA program specifically for new EHS facilities detailed in

N.J.A.C. 7:31-2.4(c), (d) and 2.10(a). Among these requirements are the following:

1. Register with the Department 90 days prior to construction;
2. Submit the following reports 90 days prior to construction
   a. Report of a safety review of the new EHS facility in accordance with N.J.A.C. 7:31-3.4(b).
   b. Report of a hazard analysis of the new EHS facility in accordance with N.J.A.C. 7:31-3.9.
   c. Report of a risk assessment according to N.J.A.C. 7:31-3.9(d).
3. Submit a summary risk management program statement for the new EHS facility prepared in accordance with N.J.A.C. 7:31-3.12 at least 90 days prior to the date the equipment is scheduled to be placed into EHS service; and
4. Submit to the Department the fees required by N.J.A.C. 7:31-2.16(d).

A major element of the regulations is the requirement that a facility will not be permitted to operate until it has in place an "established" Risk Management Program (RMP). The RMP is a combination of programs and procedures designed to minimize the risks associated with EHS handling and use. A registrant's RMP is required to include the following:

1. Safety review of design for new and existing EHS facilities.
2. Standard operating procedures.

3. Preventative maintenance program.
4. Operator training.
5. Accident investigation procedures.
6. Risk assessments for specific pieces of equipment or operating alternatives.
7. Emergency response planning.
8. Internal or external risk management audit procedures.

This review process will define specific safety features necessary for operation of the SCNR process. Technical guidelines were developed by the American National Standards Institute, ANSI, K61.1-1981 "Safety Requirements for the Storage and Handling of Anhydrous Ammonia". Design features that are considered by Ogden Martin engineering staff as necessary to satisfy these requirements include:

- containment dike to minimize exposed surface area and hence minimize evaporated ammonia quantities

- fogging spray system to control vaporized ammonia

- ambient ammonia detection system

- control and safety relief valves

Additionally, specific ongoing maintenance procedures will be developed in this regulatory review to ensure proper operation of the safety features selected.

If it develops that additional engineering requirements are required to comply with the ANSI requirements or other regulatory requirements, the cost to provide the additional safety protection would exceed those described above and estimated in Table 3-9.

Additionally, the Pennsauken Facility is subject to Subtitle A of SARA Title III which is similar to TCPA, outlining procedures for emergency planning as well as the added requirement to notify states and local emergency planning districts of hazardous substance activities. The Pennsauken County RRF will satisfy the requirements of Subtitle A by:

1. Providing the local emergency planning committee with information relevant to development or implementation of the local emergency response plan. The RMP developed to satisfy TCPA requirements will serve as the primary source for this information.

2. Designating a facility representative to act as emergency coordinator similar to the "responsible manager" required by TCPA to manage the facility's RMP.

Organic Nitrogen-Bearing Compound Formation

Some regulatory authorities and environmental engineering professionals have noted that one possible byproduct of SNCR may be hydrogen cyanide (HCN). These concerns are based on early developmental testing at coal-fired installations equipped with ESPs as the sole pollution control device. No recent testing has been performed to test this theory, although initial tests conducted shortly after the start-up of the Commerce facility did not indicate the presence of HCN.

Nitrosamines and other complex nitrogen-bearing organic compounds apparently require the catalyst present in SCR to form; based on reaction kinetics and theoretical considerations alone.

Inventory/Emissions Reporting

Because the Pennsauken County RRF is owned by a municipal authority, the facility is not covered under Subtitlte B of SARA Title III for inventory/emissions reporting. The New Jersey 1983 Worker and Community Right to Know regulations require inventory reporting of both municipal and industrial facilities, however, no reporting of emissions is required.

The New Jersey Right-To-Know regulations characterize ammonia as an environmentally hazardous substance. The Pennsauken County RRF will comply with the requirements of these regulations by submitting, upon request of the New Jersey Department of Health, the appropriate inventory forms.

Finally, the design and operating requirements of the complete DeNO$_X$ system would be subject to the review by NJDEP Division of Waste Management in accordance with N.J.A.C. 7:26-1.10(b)(6)(ii) and (iv). All engineering and safety concerns would be constructed in accord with the first approval issued by that Division.

Conclusions

BACT is an emission limitation determined on a case-by-case basis, considering technical feasibility, and economic, energy and environmental impacts. Based on the arguments presented in this analysis, BACT is not deemed use of SNCR to reduce NO_X by 35.7%

Technical issues pertaining to SNCR still need to be addressed. For example, there are no data available documenting the long term reliability of the technology, from facilities representative of the Pennsauken Facility. In addition, as the Commerce optimization study indicates, emission reductions are highly variable, due to the inherently variable nature of combustion itself. In that study, one-hour NO_X levels varied from 18% to 62%. Vendors' performance guarantees are extremely limited, guaranteeing performance for compliance testing but not long-term operation. Thus, an unreasonable amount of risk is placed on the permit applicant, who cannot be certain at all that a permit limit could be met over a five-year period. In-stack continuous emissions monitoring systems for ammonia have yet to be developed and proen to be reliable to the level where ammonia slip can be reliably controlled by monitoring and adjustment of injection rate. Finally, the long term effects of ammonium salt corrosivity on boiler/economizer heat transfer surfaces are unknown.

In addition to these serious technical uncertainties, the costs of the system are substantial: $2.6MM capital and $0.36MM to $0.45MM operating. The resulting cost effectiveness values are significantly high, at $3,980 to $4,540 per ton NO_X removed. These costs are extremely difficult to justify in light of the risks entailed with the system and the environmental impacts, including NH_3 emissions, as well as possible increases in CO emissions, not to mention the hazards posed by NH_3 transportation, storage and handling.

In addition, there is no regulatory precedent for application of Thermal $DeNO_X$ as BACT under Part C of the Clean Air Act. The Commerce facility in California installed Thermal $DeNO_X$ as "innovative technology" under the rules of the permitting authority, the South Coast Air Quality Management District. The Long Beach, California, facility located in the only non-attainment area in the U.S. for NO_X, installed ammonia injection as LAER, and the Stanislaus County facility installed the technology because that area of California is non-attainment for ozone. Under the rules of the Stanislaus County Air Quality Management District, all precursors to ozone are also considered to be non-attainment. This includes hydrocarbons and NOX. Emissions in excess of an established maximum are required to provide offsets for the difference and apply a control technology described as BACT in the County rules, but which matches the meaning of LAER under the Clean Air Act. The Pennsauken Resource Recovery Facility must install BACT, which is determined on a case-by-case basis, and not required to provide LAER.

Both the USEPA and the NJDEP appear to share the opinion that BACT for NO_X emissions from resource recovery facilities is NOT the use of Thermal $DeNO_X$. The USEPA in its Draft Regulatory Development Plan (Clean Air Act 111(b) and 111(d): Regulatory Program for Municipal Waste Combustion (published in March 1988), states on page 3-11 that "we (the USEPA) do not anticipate evaluating or requiring add-on NO_X controls (for MSW incinerators) because NO_X emissions are relatively low and controls are very costly." According to the EPA, the quantity of NO_X emissions from MSW incinerators is relatively small compared to NO_X emitted from other types of source categories. The NJDEP (Deieso, Gengos, O'Sullivan), in a paper recently presented at the 81st Annual Meeting of APCA in Dallas, acknowledges that while emissions and control of NO_X are presently under scrutiny by the DEP, the DEP has yet to require any add-on control technology. "At present, the DEP regards Thermal $DeNO_X$ as innovative technology in its demonstration stage. Although the technology is promising, the DEP is reluctant to designate it as BACT or LAER."

Based on these arguments, the use of Thermal $DeNO_X$ to achieve a 35.7% reduction (or any other rate of reduction) cannot be proposed as BACT for the proposed Pennsauken Resource Recovery Facility.

3.3 The Third Most Stringent NO_X Control Alternative

The third most stringent NO_X control alternative is the use of the combustion modification, flue gas recirculation (FGR), to achieve 15-25%

reduction in NO_X emissions. Flue gas recirculation (FGR) is a combustion modification which reduces NO_X emissions by extracting a portion of the flue gas and returning it to the furnace through the burner windbox. The system consists of an FGR fan assembly, air apportioning and mixing system, and ductwork necessary to connect the stack to the windbox. Because the recirculated flue gas is relatively cool and thereby absorbs some of the heat released during combustion, the bulk furnace temperature decreases, resulting in a reduction of thermal NO_X formation. Fuel NO_X formation is slightly reduced since the addition of flue gas to the combustion air reduces the overall oxygen available to react with the nitrogen.

FGR is commercially available and applicable to all gas and distillate oil-fired industrial boilers, since NO_X emissions due to firing of these low-nitrogen fuels are contributed mostly by thermal NO_X (EPA, 1982). Test data have shown NO_X reductions as high as 50% for gas and distillate oil-fired boilers using gas recirculation rates up to 15% with no air perheat (EPA, 1982). FGR is not, however, as effective for residual oil- and coal-fired boilers, since as much as 40 to 60 percent of the total NO_X emissions may be attributed to fuel-NO_X, the type of NO_X minimally controlled by FGR (EPA 1982).

In fact, even though <u>The Technology Assessment Report for Industrial Boiler Applications: NOX Combustion Modification</u>, published by the EPA in 1979 reviews FGR, it is discussed as a possible NO_X reduction device in the context of distillate oil- and gas-fired boilers only. It is not considered as a candidate for "best control systems" for coal-fired or residual oil-fired boilers (the type of boilers most analogous to MSW-fired boilers); therefore cost estimates for FGR addition to coal fired and residual oil-fired boilers were not supplied in that EPA publication. Tests have been performed which demonstrate NO_X emission reductions between 15 and 18 percent, achieved by recirculating up to 20 percent of the flue gas back to the burners of a pulverized coal boiler. (Bienstock, 1972).

FGR may be applied to solid waste combustion by ducting cool flue gas from a point after the air pollution control device back to the underfire air fan. Since municipal solid waste contains relatively high amounts of nitrogen, as with coal and residual oil, and since it is generally accepted that 75-80% of NO_X generated from refuse burners is due to fuel nitrogen conversion (CARB, 1984) and not oxidation of atmospheric nitrogen, flue gas recirculation is expected to achieve only limited NO_X reduction on refuse-fired boilers.

Flue gas recirculation has been employed on a limited basis at refuse-burning facilities in Japan and Europe (CARB, 1984). Results from experimentation at the 660 TPD refractory wall furnace at the Kita refuse burning facility in Tokyo indicated NO_X emissions could be reduced 25 percent by recirculating flue gas equivalent to 20 percent (by volume) of the combustion air. Further testing showed that FGR in amounts greater than 20 percent did not reduce NO_X emissions beyond 25 percent. (CARB 1984).

Though these results indicate that FGR may be moderately successful at resource recovery facilities (using refractory walled furnaces), the same effects of flue gas recirculation (i.e., lower flame temperature, and sub-stoichiometric underfire air) can probably be accomplished without FGR (Russell, 1984). Proper design of the combustion unit to maintain moderate underfire air temperatures, and proper operation to ensure underfire air at 50-75 percent stoichiometric should reduce NO_X to equivalent levels as FGR.

According to the BACT/LAER Clearinghouse and Supplement, flue gas recirculation was proposed for NO_X control at two MSW facilities, both located in California. Both the Kaiser California and Tri-Cities projects have since been abandoned.

Addition of flue gas recirculation to a boiler is considered a major modification (EPA 1979), since fans, ductwork, dampers, and a control system to regulate combustion oxygen and recirculated flue gas quantities are required. In addition, existing fan capacity has to be increased due to increased draft, and the existing boiler and ductwork enlarged to accommodate the larger gas flows.

Economic and Energy Impacts

These equipment modifications and additions represent capital cost increases and increases in operating costs, namely due to increased power requirements.

Specific data on capital and operating cost increases due to FGR as applied to refuse-burning facilities are scarce. Cost data (EPA 1979) for new distillate oil-fired boilers, specifically a 100 MM Btu/hr watertube boiler, shows a capital cost increase of $26,000. Multiplying this figure by a factor of two to account for both boilers at Pennsauken, and the ratio of cost indexes for 1986 and 1979 (Chemical Engineering, Nov. 86), 318.6/238.7, gives an estimated capital cost increase for the Pennsauken facility of $69,400.

An EPA study (EPA-600/7-79-178f) was used to estimate the increased operating costs associated with FGR. Flue gas recirculation entails additional fan power because of the extra pressure drop associated with the extra ductwork. According to the EPA, approximately 0.25% of the boilers' total heat input is equivalent to the amount of energy required for the extra fan power. Based on the intended heat input of the proposed units, 87.5 MMBtu/hr, 8760 hr/yr operation and a unit electrical cost of $0.06/kw-hr, the additional yearly cost associated with increased fan power is $72,000.

The thermal efficiency of a modified boiler may also be slightly reduced since FGR creates a lower furnace temperature. The EPA noted that, while several of the utility boilers did not experience a 1% thermal efficiency loss, 0.5% was a representative factor. A 0.5% loss for the proposed facility with a 12 MW turbine is equivalent to a 0.06 MW loss, which over 8760 hr/yr operation, costs an additional $32,000 per year. The increased operating expenses due to FGR therefore would total $104,000 per year.

To estimate the cost-effectiveness of FGR, the NO_X reduction must be identified. There is virtually no data on how FGR would perform on an Ogden Martin unit; it is conservatively assumed that 15% reduction in NO_X emissions could be achieved. This reduction corresponds to annually controlling 68 tons of NO_X. The cost-effectiveness of FGR would therefore be $1,530/ton, a considerable penalty considering the negligible reduction in ambient air impacts, as well the utter lack of experience with the technology on Ogden Martin units.

Environmental Impacts

Environmentally, addition of an FGR system to the proposed Pennsauken facility would provide negligible benefits. If NO_X were to be reduced further by 15 percent or less using FGR, the maximum annual concentration would decrease from 0.41 ug/m^3 to 0.35 ug/m^3. The added annual cost of $104,000 to reduce the ambient air concentration by 0.06 ug/m^3 is not cost effective. The effects on ambient impacts would be negligible, thus not warranting the expenditures on the additional equipment and increased power consumption. In addition, it is quite possible that inclusion of FGR, which results in lower flame temperatures, could negatively effect the environment. It is a well documented fact that volatile organic compounds (VOC), CO and certain organic species, such as dioxins (PCDD), polycyclic aromatic hydrocarbons (PAH), and polychlorinated biphenyls (PCB) are more likely to form as flame temperatures are reduced (Clarke, 1986). Thus, using a technique to reduce currently insignificant levels of NO_X by negligible amounts, at the expense of producing potentially higher impacts of such suspected carcinogens as dioxins and PAHs, is not desirable, or necessary.

These expectations are echoed in two other reports. In EPA Region 9 interoffice correspondence, it is suggested that use of FGR will worsen dioxin, furan, VOC and CO emissions (and not affect heavy metals). In the EPA's draft of Combustion Control of MSW Incinerators to Minimize Emissions of Trace Organics (1987), the EPA states that FGR is "detrimental" to organic control, even though the technology has been demonstrated for some systems (VICON, VOLUND).

Conclusions

Flue gas recirculation has not been applied widely to resource recovery facilities. Little data are available, therefore, to support that FGR will improve NO_X control when used in conjunction with the proposed combustion controls. Costs for the system can be quite high, especially for energy requirements alone. In addition, the possibility that ambient impacts of toxic organics such as dioxins could increase, supports the contention that FGR is undesirable NO_X control for resource recovery facilities. Based on these reasons, FGR is not proposed as BACT for NO_X at Pennsauken.

3.4 The Fourth Most Stringent NO_X Control Alternative

The fourth most stringent NO_X control alternative examined for the BACT analysis is the proposed NO_X control alternative: use of a properly designed, controlled and operated combustion system to achieve the optimal combination of good combustion efficiency and minimal NO_X, CO, NMHC and trace organic pollutant emissions. This practical and economical NO_X control method has been deemed BACT for the vast majority of resource recovery facilities in the United States. With the exception of NO_X emission reduction associated with fine tuning the combustion process, the NJDEP has yet to require any add-on NO_X controls for resource recovery facilities (Deieso, et al., 1988).

3.4.1 Process Description

The control of NO_X emissions from the proposed facility is inherent in the design and operation of the boilers. Control of flame temperature (below 2400°F) results from the high-excess-air operation (110 percent) and the moisture content of the refuse (20 to 30 percent). The formation of thermal NO_X is inhibited at flame temperatures below 2,400°F. The distribution of the combustion air is controlled with the Martin reverse reciprocating grate firing system and master combustion control system such that the available oxygen in the primary combustion zone is maintained at desired levels.

Approximately 50 to 70% of the combustion air is introduced in the primary combustion zone, below the grates. The fuel-rich regions of the primary flame zone cool by radiation before the combustion process is completed with the remaining combustion air. In addition, the furnace design uses slowly moving grates which inherently minimize heat release rates since the waste burns slowly on the large grate area. Spikes of flame temperatures are reduced, thus reducing thermal NO_X formation, and fuel-rich combustion regions prevent oxidation of the fuel-bound nitrogen. The remainder of the combustion air is provided by the overfire air ports located at higher levels in the furnace to insure complete oxidation of gaseous products of the initial combustion. The lengthening of the flame path via the use of overfire air also has the favorable effect of maintaining even temperature throughout the combustion zone and thus controlling NO_X formation.

Combustion in the state-of-the-art Martin GmbH Stoker Combustion system is controlled by an automatic computerized control system consisting of a microprocessor and 2 controllers. The modern dual-loop control logic developed by Martin GmbH has replaced the single-control logic in use on many of the older resource recovery facilities.

Controller 1 acts on feeder (stroke length and speed) and grate drives. The following variables may be selected for control by controller 1:

- flue gas analysis O_2, wet
- furnace temperature (for start-up)
- steam flow (in case of failure of O_2 analysis)

By controlling the grate and feed drives with controller 1, in accordance with the set point of the selected variable (e.g. O_2), the burning rate is leveled out. For example, if controller 1 is connected to O_2 content (which is measured at the economizer outlet) and the grate and feeder are started, if the O_2 set value is exceeded, feeder stroke length and speed, and grate drives are automatically adjusted until the flue O_2 level reaches the set point.

Controller 2 acts on underfire air supply by adjusting the position of the air damper. "Steam flow" is the only variable connected to controller 2. By controlling the underfire air supply with controller 2 in conjunction with the steam flow variable, the burning rate is fixed in the requested range. Through use of these two control loops, excellent combustion with minimal formation of NO_X, CO, NMHC and trace organics may be achieved.

Most modern combustion systems, including fossil fuel-fired utility and industrial boilers are equipped with feedback systems designed to control combustion. Recent Ogden Martin facilities that employ this system include those in Marion County, Oregon and Bristol, Connecticut.

There are no disadvantages in using these combustion controls to minimize NO_X emissions (as well as CO and NMHC emissions) from the proposed resource recovery facility. As previously discussed in Section 2, though NO_X emissions from modern mass-fired MSW incinerators are generally higher than those from older units, emissions of CO have been reduced dramatically. This trend is an indication of more efficient combustion, and hence, greater destruction of organics, including dioxins and furans. Tables 3-11 and 3-12, presented at the 80th Annual Meeting of APCA in New York (1987) illustrate this point. Table 3-11 presents NO_X and dioxin (as USEPA Toxic Equivalents) emission data for older resource recovery facilities tested prior to 1986. Table 3-12 presents NO_X and dioxin (as USEPA Toxic Equivalents) emission data for seven Ogden Martin facilities. Comparing the data from these tables, the proposed Ogden Martin facility may likely emit significantly lower dioxins and furans than facilities which achieved slightly lower NO_X emissions.

4.0 Summary and Conclusions

Use of a combustion system designed, controlled and operated to simultaneously achieve good combustion efficiency and low CO, NMHC, trace organic emissions and resultant NO_X emissions of 350 ppmv NO_X @ 7% O_2; (3 hr. average) is proposed as BACT for NO_X for the proposed Pennsauken Resource Recovery facility. This is the control method that has been deemed BACT for NO_X for the overwhelming majority of resource recovery facilities in the nation, including the modern, state-of-the-art facility in Passaic and Union Counties, New Jersey; Lancaster, Pennsylvania; and Lake and Pasco Counties in Florida.

Flue gas recirculation achieves slight NO_X reductions at significant energy and economic penalties, and therefore was not considered BACT.

Selective catalytic reduction at 77% control was rejected as BACT. This technology has not been demonstrated for long-term reliability, produce negligible reductions in air quality impacts and are cost prohibitive. In addition, both the NJDEP and the USEPA have recently stated in writing that they are reluctant to require add-on NO_X controls as BACT.

Thermal $DeNO_X$ at 35.7% control was also rejected as BACT. The reliability of this technology has not yet been documented over the long term, either from U.S. or Japanese installations. Performance guarantees are extremely limited, guaranteeing only initial compliance testing but not long-term operation. Additionally, this technology was ruled out for the following:

(1) Significant safety concerns with the on-site storage of anhydrous ammonia.

(2) Potential for unacceptable environmental emissions such as a visible plume or excess ammonia release with the flue gas or the formation of other pollutants, possibly cyanides and nitrosmines.

(3) Potential for additional costs incurred from increased facility downtime and maintenance.

(4) Excessive costs per ton of NO_X removed from the flue gas.

(5) High capital and operating costs.

The maximum modeled facility NO_x impacts with the proposed BACT are less than 0.50% of the applicable State and Federal annual air quality standard of 100 ug/m^3.

Although a reduction of ambient impacts will occur with the application of SNCR, this reduction does not justify the costs involved with the implementation of SNCR.

Therefore, the control strategy determined to be BACT for the Pennsauken Facility taking into consideration energy, economic, and environmental impacts, is combustion control inherent in the design and operation of the advanced Ogden Martin System.

TABLE 3-11

SELECTED AIR EMISSIONS DATA FOR FACILITIES TESTED 1980 - 1985

Facility	Date of Test	Unit	NO_x ppmdv @ 12% CO_2	NO_x lbs/MMBtu	NO_x lbs/ton	CO ppmdv @ 12% CO_2	THC ppmdv @ 12% CO_2	Dioxins and Furans[a] PCDD +PCDF (ng/Nm^3)	Dioxins and Furans[a] U.S. EPA Toxic Equiv. @ 12% CO_2)
Chicago NW	1980		—	—	—	170	<2	277	3.845
	1983		244	0.393	3.30	94.6	6	—	—
N Andover	1985	Unit 1	261	0.434	—	12	—	—	—
		Unit 2	284	0.471	—	20	—	374	6.576
		Avg	273	0.453	—	16	—	—	—
Zurich-Josephstrasse	1981		242	—	—	N/A	N/A	306	3.028
Borsigstrasse	1984		N/A	—	—	N/A	N/A	382	6.197
Stellinger-Moor	1984		N/A	—	—	N/A	N/A	540	5.686

[a] Siebert, P.C., et al. "Statistical Properties of Available Worldwide MSW Combustion Dioxin/Furan Emissions," Roy F. Weston, Inc., 80th Annual Meeting of APCA, New York, NY, June, 1987.

Source: Hahn and Sofaer (1988)

TABLE 3-12

DIOXIN EMISSIONS BY TYPE OF AIR POLLUTION CONTROL

City/County		Dates of Testing	Air Pollution Control Equipment	U.S. EPA Toxic Equivalents ng/Nm^3 @ 12% CO_2	NO_x ppmdv @ 12% CO_2	CO ppmdv @ 12% CO_2	THC ppmdv @ 12% CO_2
Wurzburg		Dec 1985	DS/FF	0.374	261	35	<1
Stockholm		Aug 1986	DS/FF	0.098	319	23	N/A
Marion County		Sep 1986	DS/FF	0.108	306	16	3(c)
EPA Baseline Test		Jun 1987		—	285	11	<1
Bristol		Jan 1988	DS/FF				
	Unit 1			0.103	281	20	3
	Unit 2			0.076	278	18	<1
Tulsa	Units 1 & 2	Jun 1986	ESP	0.701	367[a]	22	<1
	Unit 3	Oct 1987		0.697	332	15	1
Hillsborough County		Apr 1987	ESP				
	Unit 1			N/A	322	16	8
	Unit 2			N/A	329	19	N/A
	Unit 3			N/A	324	11	N/A
Alexandria/Arlington		Dec 1987	ESP	0.761	207	20	N/A

[a] reported at 7% O_2.

Source: Hahn and Sofaer (1988)

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