I. Application

A. Applicant

Tropicana Products, Inc.
P. O. Box 338
Bradenton, FL 33506

B. Project and Location

The applicant proposes to construct a cogeneration system which will consist of a natural gas fired turbine/heat recovery steam generator (HRSG) and an auxiliary boiler at Tropicana's citrus processing facility located in Bradenton, Manatee County, Florida. The project will result in emissions of nitrogen oxides (NOx), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), sulfur dioxide (SO_2), carbon monoxide (CO), and volatile organic compounds (VOCs).

The UTM coordinates of the facility are Zone 17, 346.8 km East and 3040.9 km North.

C. Facility Category

The Tropicana facility is major in accordance with Rule 17-2.100 of the Florida Administrative Code (F.A.C.). It is classified in accordance with the Standard Industrial Classification (SIC) Code as Major Group 20, Food and Kindred Products; and Industry No. 2037, Fruit Juices.

The sources are classified in accordance with the NEDs Source Classification Code (SCC) as:

a) Gas Turbine: 2-03-002-02
b) Auxiliary Boiler: 1-02-005-01, 1-02-006-02

Tropicana's application was received on November 30, 1988 and was deemed complete on January 13, 1989.

II. Project Description

The cogeneration project will consist of a General Electric (GE) LM 5000 gas turbine (GT) with an electric generating capability of 45.4 MW at conditions of 59° F, 60% relative humidity and sea level. The exhaust gases will go through a coupled heat recovery steam generator (HRSG) to produce up to 119,000 lbs/hr of high pressure steam, 191,000 lbs/hr of intermediate pressure steam and 18,000 lbs/hr of low pressure steam. Up to 20,000 lbs/hr of steam from the HRSG will be injected into the GT combustion chamber for NOx control.

Up to 50,000 lbs/hr steam from the HRSG will be used for power increase in the expansion section of the GT. The HRSG will be supplementary fired using duct burners with a maximum rated heat input of 104 MMBtu/hr. The maximum average heat input for the HRSG will be 91 MMBtu/hr. Both the gas turbine and the HRSG duct burners will be fired with natural gas only. All exhaust gases from the GT will go through the HRSG; no by-pass stack will be constructed.

An auxiliary boiler, with a maximum heat input rate of 157.4 MMBtu/hr, will also be constructed. Fuels for the auxiliary boiler will be natural gas and distillate oil; oil will only be used when natural gas is curtailed. Operation on distillate oil will be limited to a maximum of 60 days/year. The auxiliary boiler will normally be operated to supply Tropicana's steam requirements only when the GT/HRSG is not operating, or is being started-up or shut down. NOx emissions from the auxiliary boiler will be controlled by flue gas recirculation.

III. Rule Applicability

The proposed project will emit the pollutants PM/PM_{10}, NOx, SO_2, CO, and VOCs, and is subject to a preconstruction review in accordance with Chapters 17-2 and 17-4 of the Florida Administrative Code (F.A.C.) and Chapter 403, of the Florida Statutes.

The proposed project will be a major modification to a major facility in accordance with F.A.C. Rule 17-2.100, Definitions.

Tropicana's facility is located in Manatee County, in the area of influence of the particulate matter and the sulfur dioxide nonattainment areas (F.A.C. Rule 17-2.410) and in an attainment area for the other criteria pollutants (F.A.C. Rule 17-2.420).

The proposed project is subject to a Prevention of Significant Deterioration (PSD) Review in accordance with F.A.C. Rule 17-2.500(2)(d)4, since it will result in a significant net emissions increase (F.A.C. Rule 17-2, Table 500-2). Emission limitations for the significant pollutants will be determined in accordance with F.A.C. Rule 17-2.630, Best Available Control Technology (BACT).

The proposed project is not subject to Nonattainment Review Requirements for particulates and sulfur dioxide because the impacts on the nonattainment area will be insignificant, in accordance with F.A.C. Rule 17-2.510(2)(a)2.b.

The proposed project is subject to source specific emission limiting standards in accordance with F.A.C. Rule 17-2.600(5), Fossil Fuel Steam Generators with more than 250 MMBtu/hr heat input.

The proposed GT is not subject to Standards of Performance for New Stationary Sources (NSPS) in accordance with 40 CFR 60 Subpart GG because although it will be a stationary gas turbine with greater than 100 MMBtu/hr heat input, it will not be an electric utility turbine.

The proposed HRSG will be subject to NSPS in accordance with 40 CFR 60, Subpart Db since it will be an Industrial Steam Generator with a maximum heat input rate greater than 100 MMBtu/hr.

The proposed auxiliary boiler will also be subject to NSPS in accordance with 40 CFR 60 Subpart Db since it will also have a maximum heat input rate greater than 100 MMBtu/hr.

The proposed project is subject to compliance testing and reporting requirements in accordance with F.A.C. Rule 17-2.700. Compliance tests will be conducted using the following test methods in accordance with the 1988 version of 40 CFR 60 Appendix A:

a) EPA Method 5 for PM
b) EPA Method 9 for Visible Emissions
c) EPA Method 10 for CO
d) EPA Method 7 or 20 for NOx
e) EPA Method 6 or 20 for SO_2
f) EPA Method 25 for VOCs

IV. Source Impact Analysis

A. Emission Limitations

The following are the emission limitations for this project as determined by the attached BACT analysis:

Auxiliary Boiler Emissions

	Gas (8760 hrs/yr)		Oil (1440 hrs/yr)		Maximum Emissions (1440 oil + 7320 gas)
	lbs/hr	TPY	lbs/hr	TPY	TPY
NO_x	15.7	68.9	31.4	22.6	80.2
CO	19.75	86.5	20.28	14.6	86.9
PM	0.38	1.66	7.87	5.66	7.03
PM_{10}	0.23	1.0	4.7	3.4	4.2
SO_2	0.09	0.39	47.2	34.0	34.33
VOC	1.88	8.2	1.93	1.39	8.27

GT and HRSG Emissions

	NOx		CO		PM/PM_{10}		SO_2		VOC	
Unit	lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY
GT	62.6	274.3	9.1	39.8	1.5	6.6	0.24	1.07	3.6	15.9
HRSG	10.4	39.9	14.56	55.8	0.25	0.95	0.06	0.23	4.16	15.9

B. Air Quality Analysis

Tropicana Products, Inc. (Tropicana) is proposing to construct and operate a cogeneration facility. The facility will consist of a gas combustion turbine, a HRSG, and an associated auxiliary steam generator. The location of the facility will be at Tropicana's citrus processing plant in Bradenton, Manatee County.

The gas turbine will have a electric generating capacity of 45.4 megawatts (MW). Steam generated by the HRSG will be injected into the gas turbine to be used for NOx control and increased power output. Both units will be fired with natural gas and all exhaust gases from the gas turbine will go through the HRSG before exiting from a single stack to the atmosphere. The auxiliary boiler will normally be operated only to supply steam requirements when the gas turbine/HRSG is not operating, or is being started-up or shut down. It will burn either natural gas or distillate oil; distillate oil will be limited to a maximum of 60 days per year. The operation of these sources will result in the significant emissions of regulated air pollutants.

The regulated pollutants emitted from the new Tropicana sources are those associated with the burning of natural gas and distillate oil. The pollutant emissions estimated by the applicant, considering control, indicate that both nitrogen oxides (NOx) and carbon monoxide (CO) exceed the PSD-significant emission levels. The air quality impact analysis required by the PSD regulations for these pollutants includes:

- An analysis of existing air quality;
- A PSD increment analysis (for NO_2);
- An Ambient Air Quality Standards (AAQS) analysis;
- An analysis of impacts on soils, vegetation, visibility, and growth-related air quality impacts; and
- A "Good Engineering Practice (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analysis depends on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed facility, as described in this permit and subject to the conditions of approval proposed herein, will not cause or contribute to violation of any PSD increment or ambient air quality standard.

a. Modeling Methodology

All modeling completed by the applicant followed the EPA Guideline on Air Quality Models (Revised), w/Supplement A (1987). The Industrial Source Complex Short-Term (ISCST) model (version 6-88207) and the Industrial Source Complex Long-Term (ISCLT) model (version 6-88167) were used to predict the impact of the new Tropicana sources on the surrounding ambient air. Both of these models determine ground-level concentrations of inert gases and small particles emitted into the atmosphere by point, area, or volume-type sources. They incorporate elements for plume rise, transport by the mean wind, and Gaussian dispersion. In addition, the models allow for the separation of sources, building wake downwash, adjustment for calm conditions, and various other input and output features.

Five years of sequential hourly meteorological data (1982-1986) from the National Weather Service (NWS) office in Tampa were used in the models. The ISCST model uses each hour of meteorology separately to calculate short-term concentrations while the ISCLT model uses annual frequency distributions of the wind speed and direction for the different stability classes to calculate long-term (annual) concentrations. Since five years of data were used, the highest, second-high short-term predicted concentrations are compared with the appropriate ambient standards. For the annual averages the highest predicted yearly average was compared to the standards. Since the CO standards are short-term (1-hr and 8-hr), the ISCST model was used to analyze the CO impacts. While the NO_2 standard is long-term (annual) and the ISCLT model was used.

The stack and emission characteristics used in the models are listed in Table 1. The closest major source of NOx from the Tropicana facility is the FPL Manatee power plant located 24 km away. It is included in the modeling analysis. All other sources are considered background and are included as part of the estimated background concentration. Building wake downwash effects were included in the modeling by inputting the appropriate building characteristics.

Maximum concentrations were predicted at 425 receptors surrounding the Tropicana facility. The closest receptors were located along the perimeter of the plant property. Initial modeling was completed considering the new sources only (i.e., the gas turbine, HRSG, and auxiliary boiler). Each of these units were assumed to be running continuously at their maximum emission rate. The results show that for CO the maximum ground level concentrations due to the new sources are 91 ug/m^3, one-hour average and 41 ug/m^3, eight-hour average. Both of these values are far below the defined significant impact levels of 2000 ug/m^3 and 500 ug/m^3 for the one-hour and eight-hour averaging periods, respectively. Thus, no further analysis for CO is required. The results for NOx show that the maximum annual concentration due to the new sources is 1.2 ug/m^3. This value is marginally above the defined significance level of 1.0 ug/m^3. As such, the applicant completed a more extensive modeling analysis which included all other sources of NOx at the Tropicana facility and background sources. The only background source explicitly modeled was the FPL Manatee power plant; other sources were included using a general background concentration derived from local monitoring data.

A more detailed description of the modeling analysis, along with the model output, is contained in the Tropicana application. The Department has reviewed the applicant's analysis and found that it conforms with the guidelines established by EPA and followed by the Department.

b. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring may be required for all pollutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent, monitor must be submitted. Sometimes less than one year of data, but not less than four months, may be accepted when Department approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined through air quality modeling, is less than a pollutant-specific deminimus concentration. In addition, if current monitoring data already exist and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The predicted maximum air quality impacts due the increased emissions from the proposed new sources are less than the deminimus concentration levels defined for NO_2 and CO. The deminimus concentration level for NO_2 is 14 ug/m^3, annual average and for CO is 575 ug/m^3, eight-hour average. The predicted maximum concentration increases for NO_2 and CO were 1.2 ug/m^3 and 41 ug/m^3, respectively. Therefore, specific preconstruction monitoring is not required for either pollutant.

For the purposes of completing the more extensive air quality standards required for NO_2, the applicant has used the available monitoring data located near the Tropicana facility (4.2 km to the northeast) and collected by the Manatee County Public Health Unit to estimate the existing background level. Data at this (NO_2 bubbler) monitor over the past two years indicate that an existing background of approximately 24 ug/m^3, annual average is observed.

c. PSD Increment Analysis

The PSD increment represents the amount that ambient concentrations of a specific pollutant may increase above those levels that existed as of a baseline data. The EPA has proposed to include NO_2 as one of the pollutants subject to an increment analysis. The increment for NO_2 has been proposed to be 25 ug/m^3, annual average for Class II PSD areas and the baseline date is proposed to be no earlier than February 8, 1988.

The new sources at Tropicana are increment consuming sources. The maximum predicted increase associated with these sources is 1.2 ug/m^3. No other new sources of NOx have been identified in the area surrounding the facility. Thus the proposed emissions increases are not expected to increase ambient concentrations of NO_2 more than the allowed increment.

d. Ambient Air Quality Standards (AAQS) Analysis

Both pollutants subject to review (NO* and CO) have ambient air quality standards defined for the protection of public health and welfare. The total concentration at a location should not exceed these standards. The estimation of the total impact in the area surrounding the Tropicana facility is determined by adding the maximum predicted modeled concentration to an estimated background concentration for each pollutant. In the case of the Tropicana facility, the maximum increased concentrations levels for CO were less the significant concentration levels defined in Rule 17-2.100. As such, no further modeling analysis was completed and it is assumed that the increased CO emissions will not cause or contribute to an exceedance of the AAQS. For NO_2, a full analysis of all sources was completed by the applicant. Table II summarizes the maximum concentration estimates for both CO and NO_2.

Given existing air quality in the area of the Tropicana facility, emissions from the new sources are not expected to cause or contribute to an exceedance of an AAQS.

Table I
Tropicana Cogeneration Project
Stack and Emission Parameters

Source	UTM-E (km)	UTM-N (km)	Stack Height (m)	Exit Temp. (K)	Exit Vel. (m/s)	Stack Diam. (m)	NO_2 (g/s)	CO (g/s)
Gas Turbine							7.89	1.15
HRSG							1.03	1.83
GT/HRSG	346.8	3040.9	24.4	404	16.55	3.66	8.92	2.98
Aux. Boiler	346.8	3040.9	24.4	555	7.55	2.13	4.28	2.50

Note: The exhaust gases from both the gas turbine and the heat recovery steam generator (HRSG) flow through the HRSG stack.

Table II
Tropicana Cogeneration Project
Ambient Air Quality Standards Analysis

Pollutant	Averaging Time	Maximum Impact of Project ($\mu g/m^3$)	Maximum Impact of All Sources ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
NO_2	Annual	1.2	56	24 (1)	80	100
CO	1-Hour (2)	91 (3)	--	--	--	40,000
	8-Hour (2)	41 (3)	--	--	--	10,000

(1) Based on highest measured annual average NO2 concentration over the previous two years at the closest NO2 bubbler monitor 4.2 km to the notheast of theTropicana facility.
(2) The maximum predicted CO concentrations due to the project are less than the defined significance levels contained in Rule 17-2.100, Florida Administrative Code. No further analysis is required.
(3) The Department has adjusted the maximum impacts of CO to correct for incorrect emission rates used in the model.

e. Additional Impacts Analysis

1. Impacts on Soils and Vegetation

The total ground-level ambient concentration of NO_2 is predicted to be less than the secondary air quality standard. The secondary standard, for NO_2 is equal to the primary standard and is designed to protect public welfare-related values. As such, NO_2 is not expected to have a harmful effect on soils and vegetation.

2. Growth-Related Air Quality Impacts

The proposed Tropicana facility is not expected to significantly change employment, population, housing, or commercial/industrial development in the surrounding area to the extent that a significant air quality impact will result.

3. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height is defined as the greater of: (1) 65 meters or (2) the maximum nearby building height plus 1.5 times the building height or projected width, whichever is less. Applicants cannot take credit for additional pollutant dispersion from stacks built higher than GEP stack height. Both newly constructed stacks at the Tropicana facility will be 24.4 meters in height.

The applicant has addressed the potential for aerodynamic building wake downwash effects by including the nearby structure dimensions in the modeling analysis. The dimensions of these structures were varied depending on the orientation of the stack to these structures to more realistically represent wind direction-dependent downwash situations.

V. Conclusion

Based on the information provided by Tropicana, the Department has reasonable assurance that the proposed gas turbine/heat recovery steam generator and the auxiliary boiler project as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 17-2 of the Florida Administrative Code.

ATTACHMENTS AVAILABLE UPON REQUEST

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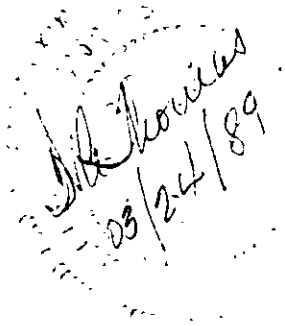

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3. Article Addressed to:	4. Article Number
Griscom Bettle, III Tropicana Products, Inc. P.O. Box 338 Bradenton, FL 33506	P 274 007 548
	Type of Service: ☐ Registered ☐ Insured ☒ Certified ☐ COD ☐ Express Mail ☐ Return Receipt for Merchandise
	Always obtain signature of addressee or agent and DATE DELIVERED.
5. Signature – Address X	8. Addressee's Address *(ONLY if requested and fee paid)*
6. Signature – Agent X Allen Frederick	
7. Date of Delivery 12/30/88	

PS Form **3811**, Mar. 1988 ★ U.S.G.P.O. 1988-212-865 DOMESTIC RETURN RECEIPT

P 274 007 548

RECEIPT FOR CERTIFIED MAIL
NO INSURANCE COVERAGE PROVIDED
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(See Reverse)

Griscom Bettle, III
Tropicana Products, Inc.
P.O. Box 338
Bradenton, FL 33506

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Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	

PS Form 3800, June 1985 ★ U.S.G.P.O. 1985-480-794

AC 41-157745
PSD-FL-136
mailed: 12/2888

Tropicana Products, Inc.
P.O. Box 338
Bradenton, Florida 34206
813 747 4461

Tropicana

208359

DATE JAN 4 1989

52-3/112

The sum of 5,000 dollars 00 cts

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By _____ Authorized Signature

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Portland, Maine 04112

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1021

RE: Tropicana Cogeneration Project - AC 41-157745, PSD-FL-45
Responses to Completeness Review

Dear Clair:

This correspondence is being submitted on behalf of Tropicana Products, Inc., to address the six questions raised in your letter dated December 28, 1988, regarding the subject project. Our responses are delineated below:

1. A $5,000.00 check payable to the Department for the Auxiliary Boiler permit fee is enclosed.

2. The latest two years of operational data for Boilers #2 - #5, #9 and #10 are submitted as Attachment 1. The operational data are for all boilers at the facility and individual statistics are not available. The estimated emissions from these boilers were based on their percentage of maximum heat input listed in Table 2-1, i.e., about 90%. The Box Plant Boiler, Sanitary Steam Boiler and Propane Vaporizer would still be operated.

   For 1986 the estimated emissions from the sources that will be shutdown are based on 509 x $10^6/ft^3$ of natural gas usage: PM = 1.3 TPY; SO_2 = 0.15 TPY; NO_x = 35.6 TPY; CO = 8.9 TPY; and VOC = 1.5 TPY. These estimates were made on the same basis as those for 1987 (see Tables 2-1 and 3-3 in the PSD Permit Application). The average of the 1986 and 1987 emission reductions are contained in the revised Table 3-3a, which is attached. Please note that the PM and PM_{10} emissions from the gas turbine have been lowered to reflect recent manufacturer information. GE estimates that the PM emissions will be less than 1 lb/hr. To reflect this estimate it was assumed that the gas turbine would emit no more than 1.5 lb/hr or 6.6 TPY (1.5 lb/hr x 8,760 hours/yr/2,000 tons/lb = 6.6 TPY). Table 3-3a presents the revised PSD applicability analysis which indicates no changes in applicability from the original permit submittal.

Main File Copy

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Bob Martinez, Governor Dale Twachtmann, Secretary John Shearer, Assistant Secretary

December 28, 1988

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Griscom Bettle, III
Tropicana Products, Inc.
Post Office Box 338
Bradenton, Florida 33506

Dear Mr. Bettle:

Re: Completeness Review, Gas Turbine Project,
AC 41-157745, PSD-FL-136

The Department has reviewed the above referenced application package received on November 30, 1988. The application has been deemed incomplete. Please submit the following information needed to complete the application:

1. Submit an additional $5000 fee for the Auxiliary Boiler.

2. Please submit two most recent consecutive, representative years' operation data (air emissions, material throughputs, production, etc.) for the existing sources which are to be shut down as a result of this project.

3. Provide details of the auxiliary boiler, if a specific model has been chosen.

4. All toxic air pollutants that may be emitted by the turbine and boilers need to be addressed with respect to the proposed control technology. For gas/oil fired turbines/boilers, the toxic air pollutants are identified in the publications entitled, "Compiling Air Toxics Emission Inventories," EPA-450/4-86-010 and "Control Technologies for Hazardous Air Pollutants," EPA/625/6- 86-014.

5. A review of the BACT/LAER Clearinghouse indicates several gas/oil fired boilers with NOx emission levels between that as proposed and that which is acheivable with SCR. In order to satisfy the "top down" approach BACT should be evaluated for control levels between these points.

6. The BACT analysis for the HRSG and auxiliary boiler should address other NOx control options including:

a) water/steam injection
b) SNCR (ammonia injection)
c) NOx - out (urea injection)
d) thermal de-NOx process

If you have any questions, please call Tom Rogers (modeling), Barry Andrews (BACT), or Pradeep Raval (permitting), at (904)488-1344, or write to me at the above address.

Sincerely,

for C. H. Fancy, P.E.
Deputy Chief
Bureau of Air Quality
Management

CHF/PR/s

cc: B. Thomas, SW District
W. Aronson, EPA
K. Kosky, KBN
Reading File } 12-28-88 AM
Pradeep Raval }
Tom Rogers
Barry Andrews

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

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DER - BAQM

Ms. Patty Adams, Planner
Bureau of Air Quality Management
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Tropicana Products, Inc. (PSD-FL-136)

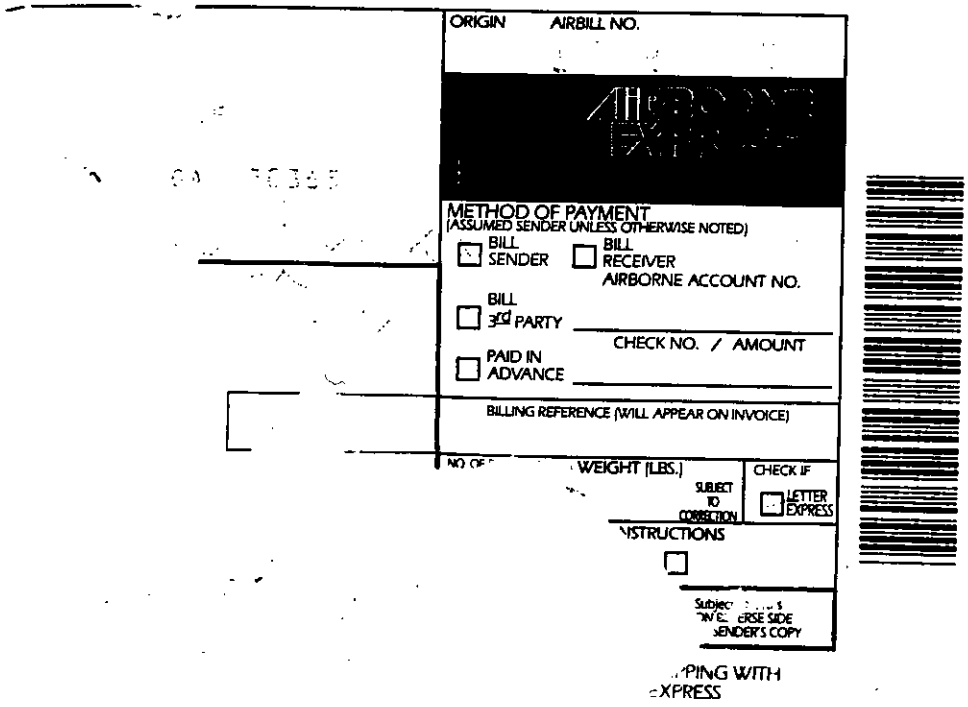
Dear Ms. Adams:

This is to acknowledge receipt of the copy of the permit application submitted by Tropicana Products, Incorporated. After reviewing the document we have some comments regarding the BACT analysis. They are as follows:

1. In dismissing Selective Catalytic Reduction (SCR) as a control option for the gas turbine (GT), heat recovery steam generator (HRSG), and auxiliary boiler, the applicant used a cost effectiveness argument. The cost analysis, appearing in Table 7-5 of the application, determines a cost effectiveness in dollars per ton of pollutant removed by dividing the total annualized cost of the add-on control equipment by the tons of pollutant removed.

   The numbers given as the maximum NO_x emissions, however, appear to be incremental numbers. The maximum emissions given for the auxiliary boiler (149.2 tons per year) are based on the emissions allowed under NSPS Subpart Db rather than on the total uncontrolled emissions. Likewise, the emissions estimates for the GT are based upon 42 ppm NO_x at 15% O_2, dry basis - a limit that the applicant proposes to reach by wet injection. As with the boiler, the emissions removed by the SCR should be based on the total emissions removed, not the incremental emissions removed after other controls which are not included in the annualized cost. The result is to give an incremental cost that is essentially a statistical manipulation. Please request that the applicant base their cost analysis on the total pollutant removed by each technology.

2. After dismissing SCR as BACT for the HRSG and auxiliary boiler, the applicant proposed burner design and natural gas firing as the next most stringent control technology. Apparently the applicant did not consider water/steam injection, ammonia injection (selective non-catalytic NO_x reduction), or urea injection (NO_xOUT). Please find enclosed copies of Exxon's Thermal DeNO_x technology and Fuel Tech's NO_xOUT process. The applicant should evaluate these technologies as they appear more stringent than burner design.


ORIGIN
AIRBILL NO.
METHOD OF PAYMENT
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BILL RECEIVER
AIRBORNE ACCOUNT NO.
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3. The applicant considered criteria pollutants and regulated pollutants in their emissions estimates. In accordance with the North County Remand, permitting authorities are required to also take the effect of unregulated pollutants (air toxics) into account in making BACT decisions for regulated pollutants. The possible hazardous air pollutants emitted by the combustion of natural gas and/or oil include formaldehyde, chlorine, antimony, barium, cadmium, chromium, cobalt, copper, manganese, nickel, zinc, and vanadium, in addition to those already considered by the applicant. The applicant should determine which, if any, of these pollutants will be emitted from their combustion processes and consider them in the BACT analysis.

Thank you for the opportunity to provide you with our comments. Please ask the applicant to address the above issues before making your preliminary determination. If you have any additional information or comments, please feel free to contact me or Gregg Worley of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
Management Division

cc: Griscom Bettle, III, Vice President
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THERMAL DeNO$_X$: A COMMERCIAL SELECTIVE NON-CATALYTIC NO$_X$ REDUCTION PROCESS FOR WASTE-TO-ENERGY APPLICATIONS

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THERMAL DeNO$_x$: A COMMERCIAL SELECTIVE NON-CATALYTIC NO$_x$ REDUCTION PROCESS FOR WASTE-TO-ENERGY APPLICATIONS

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ABSTRACT

The THERMAL DeNO$_x$ process has been licensed by Exxon Research and Engineering Company for use in over sixty commercial installations. Two installations are waste incinerators -- 300 US ton/day refuse and 360 US ton/day sludge (consisting of 3 trains each 120 US ton/day), both in the Los Angeles Basin. The process offers the advantages of high deNO$_x$, low investment and low risk of downstream equipment fouling. This paper describes the technical and economic advantages for application of the process to waste incinerators.

INTRODUCTION

THERMAL DeNO$_x$, a selective non-catalytic NO$_x$ reduction process, was invented just over 12 years ago and is a patented process of Exxon Research and Engineering Co. (1,2). The process involves the injection of ammonia (NH_3) into the high temperature flue gas in the 1600°F-2200°F (870°C-1200°C) temperature range. The original applications were in Japan beginning in 1974 where deNO$_x$ performance ranging up to 65% was achieved. Total commercial applications to date number over sixty, as shown in Table 1, and commercial performance in excess of 80% deNO$_x$ has been achieved utilizing recently improved technology.

The type of installations to which the process has been applied are wide ranging including gas and oil-fired steam boilers, utility boilers, process heaters, municipal incinerators, oil field steam generators and a glass melting furnace. Tests on flue gas generated by coal combustion have demonstrated the applicability of the process to coal-fired utility boilers, and two coal-fired utility boilers are currently under license in Germany.

One of the earliest applications of this process was a test conducted at the Kobe City, Japan incinerator during December, 1975. Even though this test involved the use of older technology and no attempt was made to optimize NO$_x$ reduction, greater than 50% deNO$_x$ was achieved. In another test deNO$_x$ efficiency of greater than 85% was achieved (3). Current units under construction include a 300 US ton/day municipal refuse incinerator and a 360 US ton/day sludge-fired incinerator.

Recently, development of a fundamental kinetic model of the process chemistry has significantly expanded the understanding of process variable interactions (4). This model, along with a knowledge of other physical factors affecting performance, is used to accurately predict performance and NH_3 breakthrough for any type of fired equipment.

Most of the applications to date have involved positioning an array of injector pipes or an injection grid within the flue gas stream at the proper flue gas temperature for injecting NH_3 (5,6). Location of the grid is critical to achieving optimum performance; but too often, especially in retrofit situations, the optimum position is inaccessible. Because of this and to account for lower than optimum temperature at reduced loads, the simultaneous injection of hydrogen has been used to extend the process effectiveness to lower flue gas temperatures. However, recent development of novel injector designs along with techniques to better assess their effectiveness has virtually eliminated the use of grids and their associated problems, and the use of hydrogen (7,8,9). These developments coupled with the kinetic model comprise the improved technology.

The improved technology offers the following major advantages:

- Higher performance
- Better load following without hydrogen
- Grid-less injectors
- Lower capital investment

Field tests of the novel injector designs located optimally have revealed substantially greater performance capability of 70% to over 80% $deNO_x$. In effect, the process now offers performance approaching that of competing catalytic processes for a wide range of fired equipment, while also achieving even greater cost effectiveness through the combination of lower investment and higher performance.

KINETIC MODEL EXPANDS PROCESS UNDERSTANDING

THERMAL $DeNO_x$ is a non-catalytic process based on the gas phase homogeneous reaction between the NO_x in flue gas and NH_3 which produces nitrogen and water (1). In general, NH_3 is injected into the hot flue gas by means of either air or steam carrier gas at a point in the flue specifically selected to provide optimum reaction temperature and residence time. The following two reactions govern the overall process:

1300°F to 2200°F (700°C to 1200°C)

$$NO + NH_3 + O_2 + H_2O + (H_2) \longrightarrow N_2 + H_2O \qquad (1)$$

above 2200°F (above 1200°C)

$$NH_3 + O_2 + H_2O \longrightarrow NO + H_2O \qquad (2)$$

As indicated by reaction 1, hydrogen (H_2) can be injected along with NH_3 to extend the effectiveness of the $deNO_x$ reaction down to the range of 1300°F (700°C).

Reactions 1 and 2 summarize the overall effect of the deNO$_x$ reaction, but they do not reveal the complexity of interaction of numerous intermediate chain branching reactions involving certain key free radicals. This complex chemical mechanism includes a total of 31 significant reactions. Rate equations, involving these thirty-one reactions, have been developed using both reliable published data as well as experimental data to yield a fundamental kinetic model of the process chemistry. Calculated results with the model correlate with an extensive set of experimental data within $\pm$7% (2).

The kinetic model has been successful in assessing the process capability through a more precise calculation of the interaction of flue gas constituents and physical conditions including temperature, time, initial NO_x, NH_3/NO_x ratio, O_2, H_2O and free radicals. This technology has enabled extension of the temperature window using NH_3 alone from under 1600°F (870°C) to over 2200°F (1200°C) under certain conditions of the other kinetic parameters. The model can be used to determine the optimum amount of NH_3 which should be injected at a given location. Also the model permits accurate prediction of unreacted ammonia.

The kinetic model calculations represent kinetic limit performance for the process and this may be lowered in a real system due to one or more of the engineering design or unit specific parameters including mixing, carrier rate, flue gas temperature and velocity gradients, and staged injection. The influence of each of these parameters has been the subject of considerable research and development and some work in this area is being continued. Mixing effectiveness of grid injectors has been increased such that it is possible to achieve 95-100% of the kinetic limit performance (6). Wall injector mixing can now be optimized for a specific geometry by utilizing a recently field-validated three-dimensional flow modeling technique (10,11).

WALL INJECTORS REPLACE INJECTION GRIDS

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 (5,6). Sometimes, multiple grids and/or hydrogen were employed to achieve some load following, but this increased the complexity and cost of the installation. Also, many potential users questioned the long term operability of the grid particularly in corrosive, erosive or heavy fouling flue gas streams such as occur with refuse-firing. In most applications today, the injection grids are being superseded by wall injectors which consist of large jets located at or near the boundary walls of the injection zone.

The wall injectors are simple and relatively inexpensive, but require careful design and placement in order to achieve optimum process results. They are not subject to overheating upon loss of carrier, nor do they face corrosive attack and/or collection of fuel ash deposits such as may result from firing heavy fuel oil, coal or refuse. These factors permit location of the injectors at the optimum flue gas temperature even within the combustion zone of fired equipment. To accomodate turndown operation, two sets of injectors may be used with very little impact on overall cost. Through proper location of the injectors to cover the load range, the necessity of hydrogen injection to promote low flue gas tem-

perature performance is eliminated. In addition, if flue gas temperatures during operation of a unit are substantially different from those anticipated in the design, the wall injectors may be relocated either onstream or during a short outage.

FLOW MODELING PERMITS OPTIMIZATION OF WALL INJECTORS

While the wall injectors offer substantial benefits over injection grids, they also pose a challenging problem to achieve adequate mixing especially in very large fired equipment. This has spurred development of a three-dimensional, turbulent flow modeling technique (11). Use of this technique coupled mathematically with the kinetic model, permits the direct calculation of $deNO_x$ performance for any geometry and flow condition.

The use of this modeling technique in predicting $deNO_x$ performance is shown graphically for a 300 US ton/day municipal refuse incinerator/boiler and a 120 US ton/day sludge-fired incinerator/boiler.

The municipal refuse incinerator shown in Figure 1 is a stoker-fired unit which utilizes a reciprocating grate. Flue gases from the burning refuse travel upward through a combustion chamber into the superheater and steam generating tube bank, then down through an economizer, and exhaust through a scrubber and baghouse.

The ammonia injectors are arranged in two zones at two elevations of the combustion chamber. Zone 1 is planned for high loads and Zone 2 for lower loads.

Calculated performance results at 100% load are shown in Figure 2 for one-fourth of the flue gases. Here, combustion chamber temperatures vary from approximately 1830°F (1000°C) to 1550°F (840°C) over the reaction zone at full load. Predicted performance results are well in excess of 70% $deNO_x$ for this installation, reducing the NO_x from an initial level of 204 vppm to less than 60 vppm (average).

The sludge incinerator shown in Figure 3 utilizes a circulating fluidized bed type combustor. Combustion is completed in the furnace shaft after which primary particulate removal is achieved. The cleaner flue gases then pass consecutively through a superheater, economizer, multiclone and air preheater. Flue gas exits the heat recovery section and is sent to a dry scrubber and baghouse before being sent to the stack.

Two zones of injectors are provided for this boiler, one in the furnace shaft and one downstream of the primary particulate removal. Due to the low flue gas temperature of 1550°F (840°C), it is necessary to inject a mixture of NH_3 and hydrogen to achieve the necessary reaction efficiency. NO_x reduction required to meet permit conditions is approximately 46% and this is well within the process capability limit. Figure 4 illustrates the effectiveness of mixing of a zone of injectors located at the wall of the furnace shaft.

POTENTIAL USER CONCERNS

One of the major concerns over use of ammonia injection in reducing NO_x generated by refuse combustion is the effect of residual NH_3 in the flue gas.

Residual NH_3 may react with sulfuric acid (H_2SO_4) and hydrochloric acid (HCl) to form ammonium sulfate ($(NH_4)_2SO_4$), ammonium bisulfate (NH_4HSO_4) and ammonium chloride (NH_4Cl). These salts can contribute to fouling and/or plume formation if present in sufficient quantities. Also, there is minimal industry experience on the effect of ammonia or ammonium salts on scrubbers and baghouses, and thus this is a potential problem area.

The three potential ammonium salts have very different characteristics. $(NH_4)_2SO_4$ is a dry salt with a neutral pH. Its small particle size of 1-3 microns further reduces the fouling tendency of this compound. NH_4HSO_4, on the other hand, is an acidic hygroscopic compound with a relatively low melting point--as low as 266°F (130°C). When present, this compound can contribute to significant fouling and corrosion in low temperature heat recovery equipment.

NH_4Cl is a dry, neutral pH, white salt which forms at very low temperature on the order of 250°F (120°C) or less. This salt can contribute to a visible plume when present in sufficient concentrations.

On the positive side, one similar characteristic of all three ammonium compounds is their high water solubility. This makes deposit removal by water washing relatively straightforward.

Equilibrium reactions in the low temperature flue gas are shown in Figure 5 for a typical refuse-fired incinerator. Due to the low sulfur content of the refuse, the amount of H_2SO_4 formed is only 2 vppm. This reacts with NH_3 at about 390°F-360°F (200°C-180°C) to produce 2 vppm of $(NH_4)_2SO_4$. At approximately 250°F (120°C), the remaining NH_3 begins reacting with HCl forming NH_4Cl. This reaction is essentially complete at 190°F (90°C) when all of the residual NH_3 is reacted.

The impact of $(NH_4)_2SO_4$ is expected to be negligible due to its small quantity and innocuous nature. It is anticipated that the additional particulate which it represents will not be detectable compared to the much larger particulate quantity typical of the flue gas from refuse-fired equipment. It will normally be removed from the flue gas by a scrubber or particulate control device. Since no NH_4HSO_4 is predicted in this case, the elimination of H_2SO_4 is actually beneficial in reducing the potential for wet, acidic deposits at the cold end heat transfer surfaces such as economizers or air preheaters.

The impact of NH_4Cl formation will be a function of the type of cleanup equipment utilized and its operation. For instance, if a dry scrubber is utilized with an outlet temperature of 190°F (90°C), essentially all NH_4Cl will form and be removed in the scrubber. If the scrubber effluent is then sent to a baghouse, any residual NH_4Cl will be removed as a particulate. Experience has also shown that reduction of residual NH_3 is effective in limiting NH_4Cl plume formation in plants not equipped with scrubbers (3,12). In most cases, predicted residual NH_3 in refuse incinerators can be maintained below 10 vppm while still attaining 70% or greater NO_x removal.

HOW MUCH DOES IT COST?

Cost information for the improved deNO$_x$ technology applied to refuse-fired boilers shows that the process is highly cost effective when high NO$_x$ reduction is required.

To illustrate the cost effectiveness, investment and operating costs are provided for a 1000 US ton/day municipal refuse incinerator facility. It is assumed that this plant has two trains, each combusting 500 US ton/day of refuse, and the heat is used to generate superheated steam. Untreated flue gas contains 230 vppm NO$_x$ at 12% CO$_2$ (dry), and 65% NO$_x$ removal is required.

The deNO$_x$ facilities include one 120 lb/hr NH$_3$ vaporizer, one 12k gallon liquid NH$_3$ storage tank, injectors, piping and analog instrumentation. A schematic of this equipment is shown in Figure 6. The vaporizer is designed to provide NH$_3$ for both units at the maximum rate required, and is electrically heated. The storage tank holds sufficient ammonia to allow operation of both boilers for approximately two weeks at design load. Two zones of independently controlled injectors are provided for each boiler because of the variations in firing conditions and flue gas temperatures that can be expected when firing refuse.

As shown in Table 2, the estimated investment cost for the equipment totally erected is $725k. Equipment cost is $350k. Indirect cost is $375k and includes field labor overheads, construction supervision and equipment, labor wage taxes, erection fee, engineering costs and contingency. Excluded from these costs are such items as land, owners' charges and licensing fee. Costs are on a third quarter 1985 Southern California basis.

Also shown in Table 2 is the cost effectiveness for this installation both in $/lb ($/kg) of NO$_x$ removed and $/US ton ($/t) of refuse. Annualized costs are obtained by assuming a five year payout on investment and adding annual operating costs. For this system, the cost effectiveness is $0.47/lb ($1.03/kg) NO$_x$ removed, and the incremental cost is $1.55/US ton ($1.82/t).

Annual operating costs are shown in Table 3. These costs are based on a 100% load factor and include values for NH$_3$, steam carrier and electric power for NH$_3$ vaporization. The operating cost per US ton of refuse is $1.25($1.38/t).

SUMMARY

Significant technological advances have been made with this deNO$_x$ process. The major benefits of these advances are a greater cost effectiveness through lower capital investment coupled with higher performance. In addition, the use of advanced analytical techniques to solve the interaction of both kinetic and engineering parameters permits the quantification of process effectiveness for a wide range of types of fired equipment and operating conditions.

The improved deNO$_x$ technology is particularly advantageous in facilities such as municipal refuse incinerators and coal-fired boilers which combust a high-ash fuel. Injection of NH$_3$ can now be accomplished in most cases without the need for internal injection grids which could be subject to fouling and corrosion/erosion damage. In addition, the need for constant carrier supply to

the grid to prevent overheating is eliminated thus saving capital investment and operating expenditure. These and other advantages discussed herein for the improved deNO_x process result in a high efficiency, relatively inexpensive NO_x reduction process suitable for all types of stationary combustion equipment.

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Table 1

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 Steamer (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		

Table 2

INVESTMENT COST AND COST EFFECTIVENESS FOR THERMAL DeNO$_x$ APPLIED TO 1000 US TON/DAY MUNICIPAL INCINERATOR

Capital Investment [1], k$

Equipment,[2]	350
Indirect[3]	375
Total	725

Cost Effectiveness[4]

$/lb ($/kg) NO_x removed = 0.47 (1.03)
$/US ton ($/t) refuse = 1.65 (1.82)

NOTES:

1. Investment costs are on a third quarter 1985 Southern California basis.
2. Includes equipment items identified in text.
3. Includes field labor overheads, construction supervision and equipment, labor wage taxes, erection fee, engineering costs and contingency. Excluded are such items as land, owners' charges and licensing fee.
4. Cost effectiveness is based on an annualized cost consisting of capital based on a 5-year payout and annual operating cost. This is divided by annual NO_x reduction based on 65% NO_x removal and annual tons of refuse.

1 US ton = 907.2 kg

Table 3

ANNUAL OPERATING COST FOR THERMAL $DeNO_x$ APPLIED TO 1000 US TON/DAY MUNICIPAL INCINERATOR

Item	Annual Consumption[1]	Unit Cost	Annual Cost
Ammonia	481.8 US tons	$250/US ton	120,450
Steam[2]	27,156 US tons	$ 12/ US ton	325,872
Electricity[3]	157.7 MWh	$ 60/MWh	9,461
			$455,783

NOTES:

1. Assumes 100% load factor.
2. Low pressure steam (15 psig or 1 bar min.) for carrier.
3. Power requirement for NH_3 vaporizer.

1 US ton = 907.2 kg
1 MWh = 3.6 GJ

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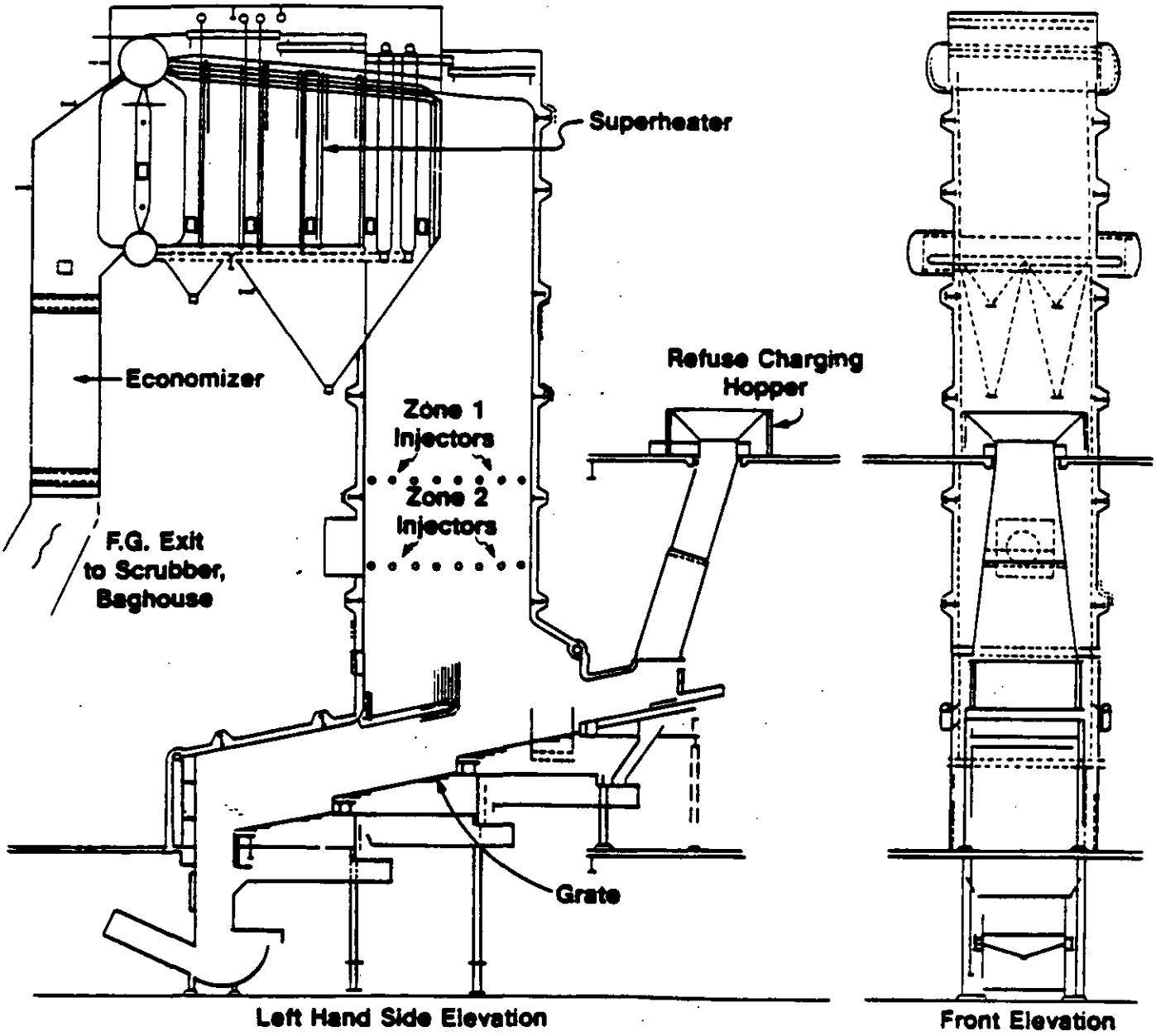
Figure 1

THERMAL DeNO$_x$—300 US TON/DAY MUNICIPAL REFUSE INCINERATOR



1 US ton = 907.2 kg

Figure 2

ILLUSTRATION OF DeNO$_x$ REACTION MODELING RESULTS FOR 300 US TON/DAY MUNICIPAL REFUSE INCINERATOR

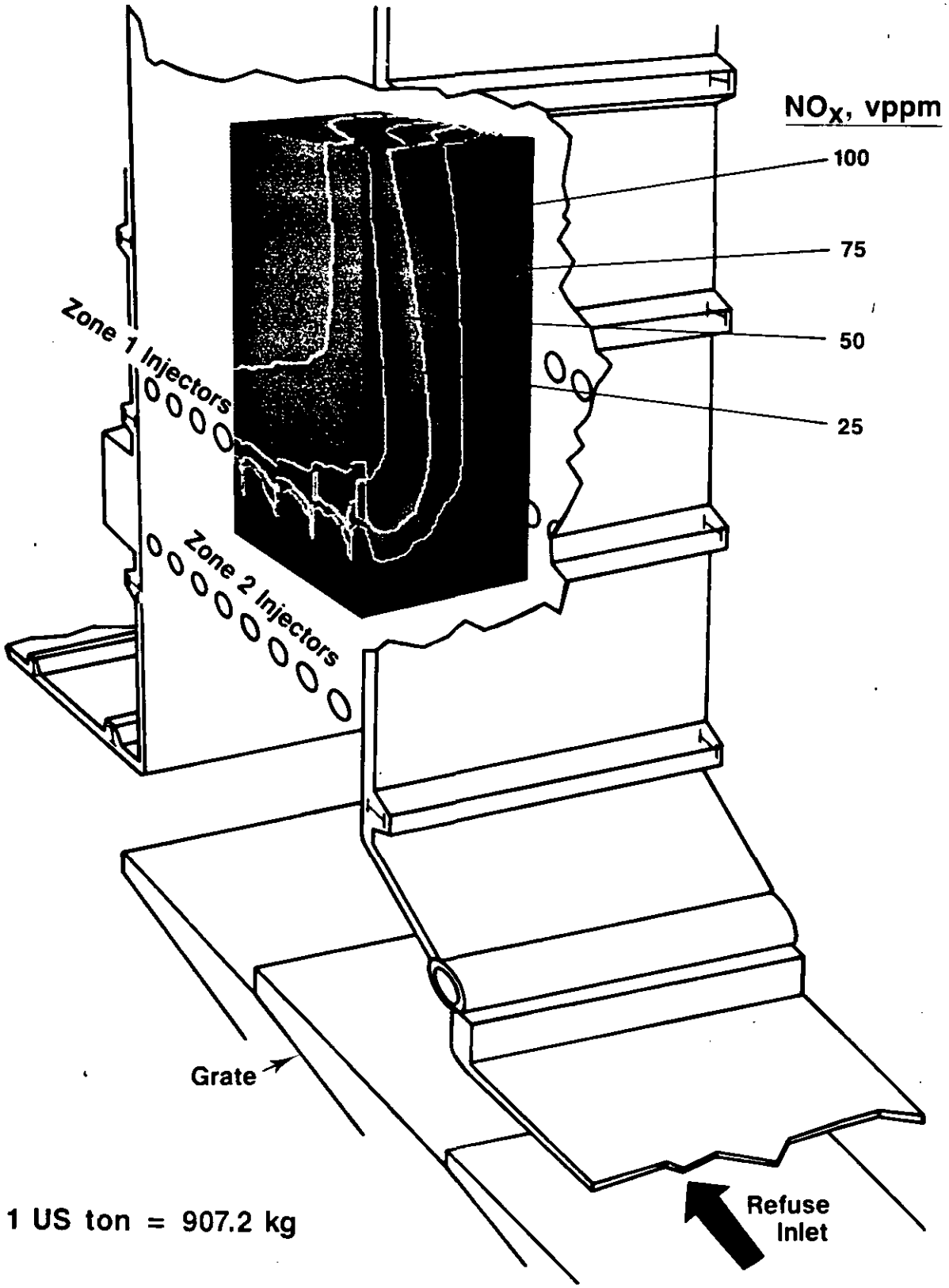


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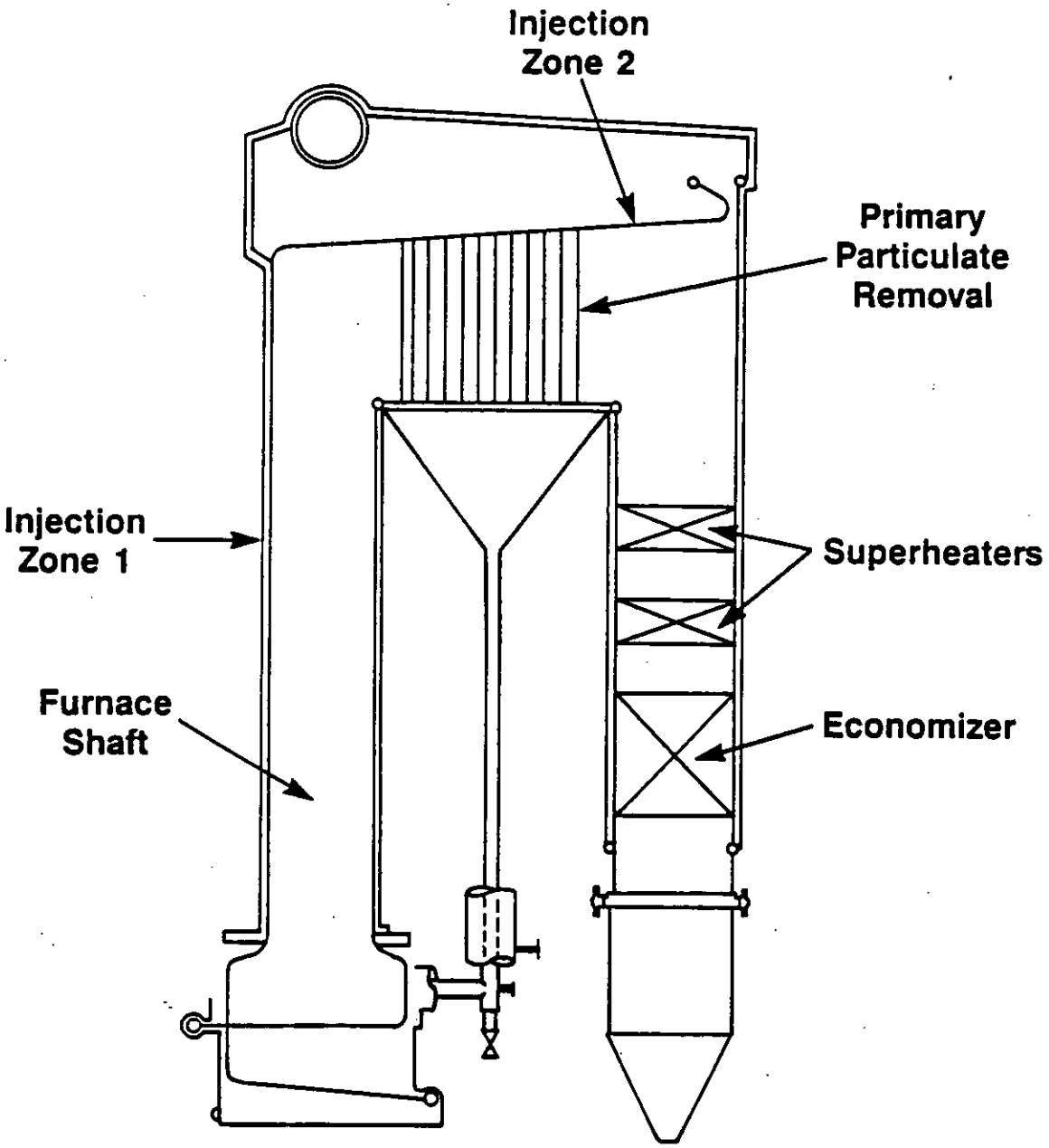
Figure 3

THERMAL DeNO$_x$ – 120 US TON/DAY SLUDGE-FIRED INCINERATOR



1 US ton = 907.2 kg

Courtesy Babcock & Wilcox Co.

Figure 4

ILLUSTRATION OF DeNO$_x$ INJECTOR MIXING FOR 120 US TON/DAY SLUDGE-FIRED INCINERATOR

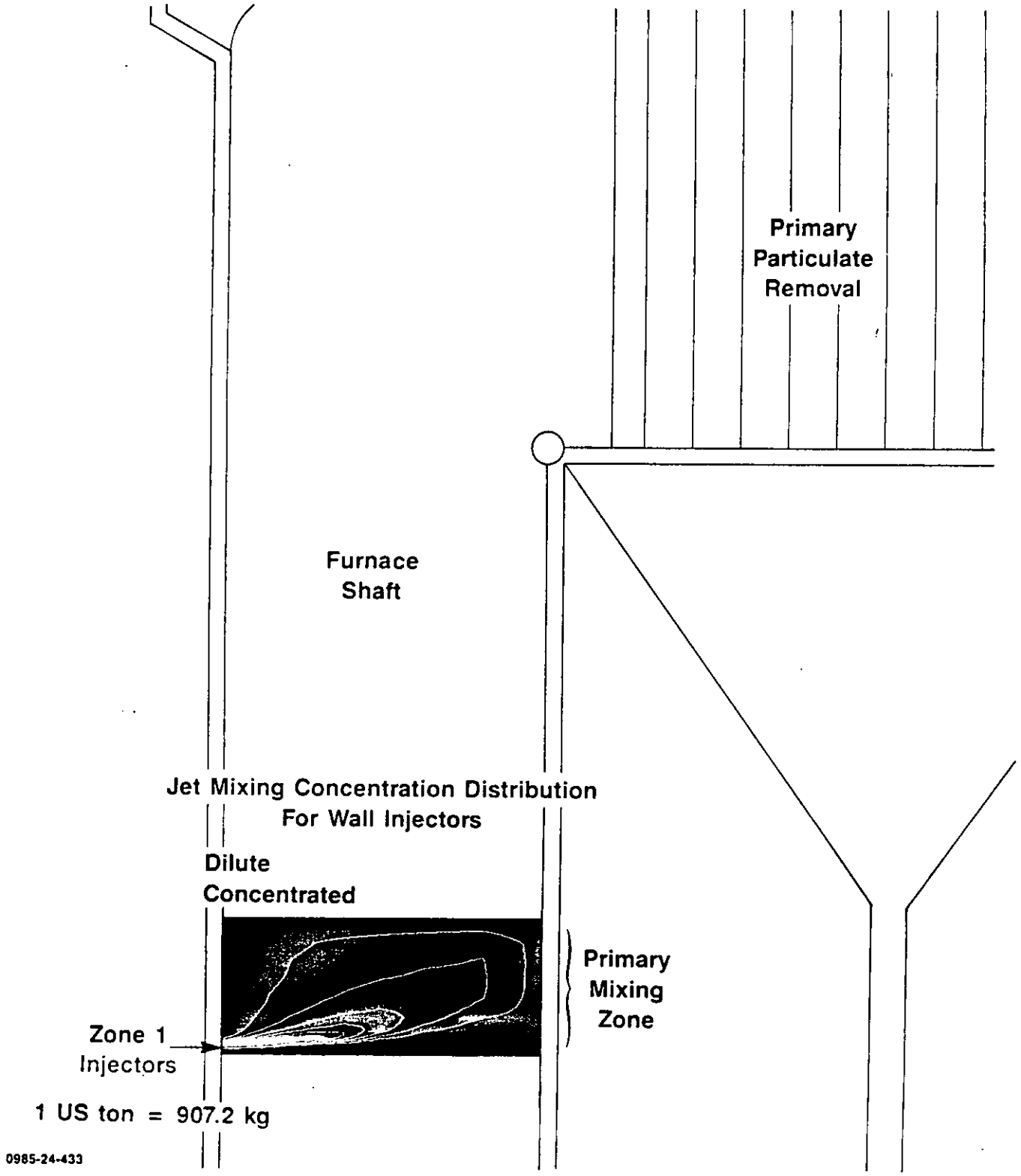


Figure 5

EQUILIBRIUM REACTIONS IN COOLED FLUE GASES FROM COMBUSTION OF MUNICIPAL REFUSE

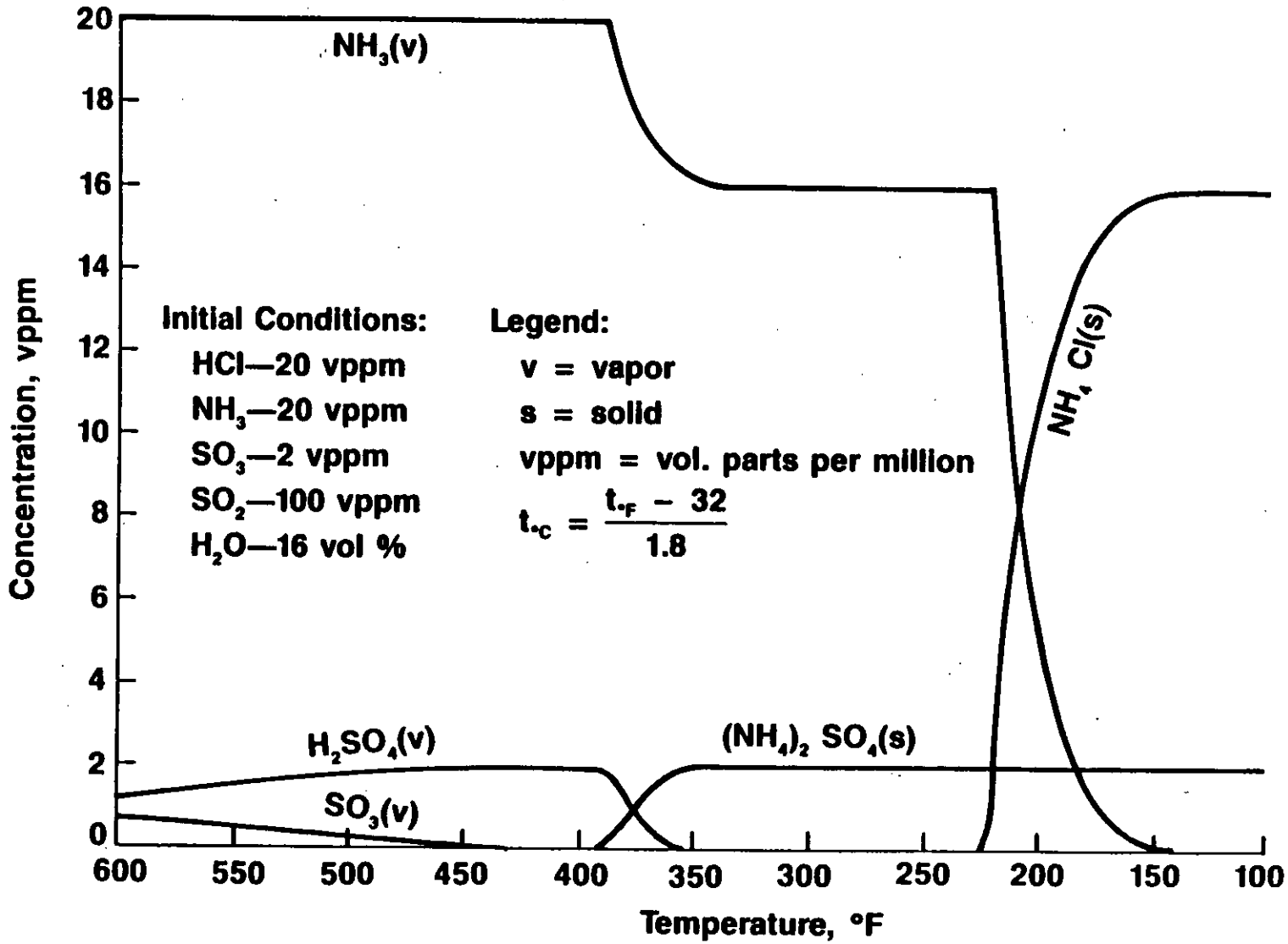


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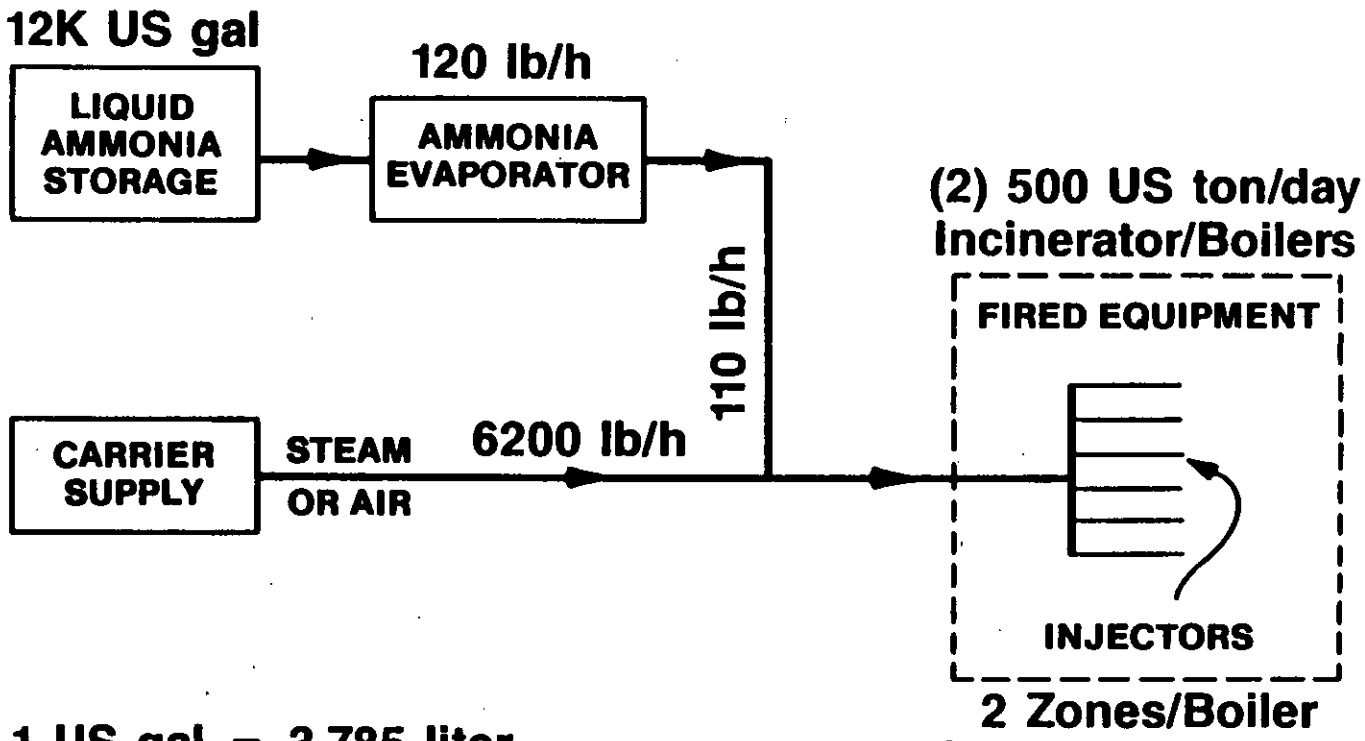
Figure 6

SIMPLIFIED THERMAL DeNO$_x$ SUPPLY SYSTEM FLOW DIAGRAM



1 US gal = 3.785 liter
1 lb = 0.4536 kg
1 US ton = 907.2 kg

THE NOxOUT(R) PROCESS FOR REDUCTION OF NITROGEN OXIDES

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The NOxOUT(R) Process for the control of nitrogen oxide emissions from stationary sources has been receiving increasing attention over the past year. This paper describes this new process, its advantages and its current status.

CONTROL OF ACID RAIN

Today, both sulfur and nitrogen oxides (NOx) are recognized as important contributors to acid rain, an atmospheric condition that can severely damage vegetation(1). Control of sulfur oxides emissions has received much more attention during the last 10 years than control of nitrogen oxides. As a result, sulfur oxides control technologies are at a more advanced state of development. Yet, there has been increasing awareness of the importance of controlling nitrogen oxides, leading to important new initiatives in technology development and the promulgation of more stringent regulations.

CONTROL OF NITROGEN OXIDES

Nitrogen oxides from stationary sources can be reduced in several ways:

- removal of nitrogen from the fuel before combustion
- modification of the combustion process to reduce nitrogen oxide formation
- catalytic reduction of nitrogen oxides in the flue
- non-catalytic (thermal) reaction of nitrogen oxides to produce N_2 gas.

Removal of nitrogen from fuels such as coal is costly and is of limited benefit because some 50% or more of the nitrogen oxides in the flue gas arise from fixation of atmospheric nitrogen during the combustion process (thermal NOx). Combustion modification generally involves modifying the combustion process in a manner that will reduce the formation of NOx. This is normally done by staging the combustion and/or recirculating flue gas to reduce the peak flame temperature(2) NOx reduction by combustion modification is generally limited to the range of 20-50%.

NOx will react with NH_3 in the presence of a catalyst at temperatures of about 300-400°C to yield N_2 gas and H_2O[2]. This process requires a relatively high initial investment and high operating costs. At higher temperatures (850-1,100°C) NH_3 will react with NO in the presence of O_2, but in the absence of a catalyst to yield N_2 and H_2O[3].

The Electric Power Research Institute (EPRI) initiated research in 1976 on the use of urea to reduce nitrogen oxides[4] and subsequently patented the urea-based reduction process[5,6].

Starting with the EPRI inventions, Fuel Tech made a number of contributions to improve the application of the technology and broaden the effective temperature range of the reaction. These contributions include chemicals to enhance urea[7], preferred process configurations and conditions, process control methods and injector design. In 1987 Fuel Tech became the exclusive worldwide licensing agent for this technology. The result is the NOxOUT Process.

THE NOxOUT PROCESS

In the NOxOUT Process, an aqueous solution containing urea and chemical enhancers is injected into the products of combustion at one or more locations, depending on the type and size of the unit. The enhancers are readily available, and require no special safety precautions. NOxOUT chemicals react with the nitrogen oxides in the combustion gas to form nitrogen gas, water and carbon dioxide. The exact reaction mechanism is uncertain, owing partially to the complexities of urea pyrolysis[8] and also to the vast number of free radical reactions occurring at typical reaction temperatures[9]. The overall reaction between urea and NO can be expressed as follows:

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

The initial reaction is believed to be the formation of NH_2 radical which then reacts with NO according to various reactions as described by Kimball-Linne and Hanson[9]. The role of the chemical enhancers is believed to be in the moderation of the free radical pool available to sustain the NO reducing reactions.

The overall chemical reaction indicates that one mole of urea will react with two moles of NO. Results of test data indicate that greater than stoichiometric quantities must be injected to achieve a desired level of removal. Excess chemicals degrade to nitrogen, carbon dioxide and small amounts of ammonia. The Normalized Stoichiometric Ratio (NSR) is used to describe the amount of urea used relative to the amount of NOx present and is defined as follows:

$$NSR = \frac{\text{Actual Reagent Molar Ratio*}}{\text{Stoichiometric Reagent Molar Ratio*}}$$

* based on initial untreated NOx

PROCESS REQUIREMENTS

In order to be effective for the control of NOx emissions from stationary sources, a technology must meet the following requirements:

- Provide the required degree of NOx control without detrimental secondary emissions, e.g. ammonia
- Have the flexibility to handle the wide range of conditions
- Be easily retrofittable
- Be safe and cost effective

The NOxOUT Process meets these requirements in the applications that have been investigated thus far, as discussed subsequently. Results obtained indicate that the technology will be effective for a broad spectrum of stationary source applications.

HIGH DEGREE OF CONTROL ACHIEVABLE

Urea provides a high degree of control of NOx when two conditions are met. First, the chemical must have high activity for reduction at the treatment temperature and second, intimate mixing of NOx and chemical must be achieved.

When these conditions were achieved in a circulating fluidized bed, over 80% reduction was obtained (Figure 1). Ammonia was the only potentially deleterious secondary product detected, and the concentration was limited to less than 5 ppm by controlling the amount of urea employed. When an NSR of over 1.9 was used, ammonia breakthrough occurred.

Note that doubling the rate of urea addition from an NSR of 1 to an NSR of 2 has only a relatively small effect on NOx reduction. Thus, these data show that a third condition must be met in order to achieve a high degree of NOx control with a low level of ammonia: the proper amount of chemical must be used.

The small amount of NH_3 produced as a by-product of the reaction, must generally be minimized because it is a pollutant and in combination with sulfur oxides from high sulfur fuels tends to form ammonium sulfates and/or bisulfates in an air preheater. Also, in coal applications, it contaminates the ash. Levels of 5 to 20 ppm in flue gas appear satisfactory depending on local requirements and are obtainable with the NOxOUT Process.

ENHANCERS EXTEND TEMPERATURE RANGE OF PROCESS

As mentioned previously, enhancer chemicals are very effective in expanding the temperature range of the process. Urea alone in water has a high NOx reduction activity at roughly 900-1,100°C. By using enhancers and adjusting concentrations, urea is effective from about 800 to 1,150°C (Figure 2). Enhancers can be used to alter both the optimum temperature of reduction and the range over which a given composition is effective (Figure 3).

Certain enhancer chemicals alone are used in the 550-800°C region and effect substantial reduction. (Figure 4). Thus, chemicals are available to treat flue gases from roughly 550-1,150°C, providing wide flexibility to inject chemicals at practical locations in existing boilers. These chemicals are widely available and do not require any special conditions for safe storage and handling.

INJECTORS IMPORTANT TO PROPER DISTRIBUTION

In order to achieve intimate mixing of NOx and reduction chemicals, the solution must be properly distributed. The introduction of aqueous solutions of urea and enhancer chemicals into the flue gas of a boiler is relatively simple. However, reliable means of quantifying the extent of distribution do not currently exist, because of variations in flue gas velocity profiles, NOx levels and temperatures. Several approaches are being used to improve distribution:

- Injectors are designed to give proper penetration based on boiler geometry
- Injectors are spaced to be consistent with spray patterns generated
- Multiple level injection is used, when required.

This is an area in which significant progress is still being made, and each new generation of injectors improves performance.[6]

MULTIPLE LEVEL INJECTION EFFECTIVE

The capability to tailor the chemical composition for a specific reaction temperature provides the opportunity to inject the NOx reducing chemical at various points in the furnace exit, referred to here as multiple level injection.
Use of multiple level injection provides a means of increasing the level of reduction and minimizing ammonia (Figure 5). In this way the NSR at a given level can be limited while achieving the level of reduction desired. In one case, significantly higher reduction was achieved before NH_3 breakthrough with two levels of injection than with one (Figure 6).

In another series of experiments in a commercial boiler fired with brown coal, it was possible to control ammonia breakthrough by injecting at two separate levels and adjusting the relative amounts of urea and enhancer chemical at each of the two levels (Figure 7). At this same boiler it was then possible to increase NOx reduction by an additional 6% (15% of the remaining NOx) by injection of an enhancer chemical at a third level with no increase in the level of by-product NH_3.

RETROFIT DEMONSTRATIONS SUCCESSFUL

The process has been successfully applied to a wide variety of fuels including hard coal, brown coal, oil, gas, wood waste and municipal solid waste. Boilers tested have included front-fired, corner-fired and circulating fluidized beds.

Boiler Type/Size	CFB 1	Pulv. Coal Test Unit 1	Pulv. Coal Wall Fired 50	Front Fired 110	Pulv. Coal Wall Fired 150	Incinerator Munic. 15
Fuel	Wood Waste	Brown Coal	Hard Coal	Nat. Gas #6 Oil	Brown Coal	Solid Waste
Temp.,°C	855-900	655-1,000	700-1,100	870-1,040	650-1,050	700-1,000
NOx Reduction, %	60	25-90	60-83	Gas 45 Oil 70	45-60	50-70

The thorough demonstration of the urea-based process for application in a utility gas or oil-fired boiler has been described previously by Mansour, et al.[10].

In 1987 reductions of 50 to 60% were achieved with 5 ppm ammonia in two coal boilers in Europe (Figure 8). One was a 50 MWe front-fired boiler using hard coal and the second was a 150 MWe corner-fired unit burning brown coal. At 20 ppm ammonia the reduction level increased to 65-75%. Data analysis indicates that better results are achievable as injection technology improves.

PROCESS ECONOMICALLY ATTRACTIVE

Engineering studies carried out as part of the commercialization effort show that the process is economically attractive (Figure 9).

Combustion modifications have the lowest cost, but provide only 20-50% reduction. NOxOUT is capable of providing up to 75% reduction at a somewhat higher cost. And SCR, which gives 60-85% control, costs roughly 3-5 times as much as NOxOUT.

In absolute terms, NOxOUT costs roughly $1000/Ton for 70% reduction when added to an existing 300 MW coal-fired unit in the U.S., operating 70% of the time.

NOxOUT APPROACHING COMMERCIAL USE

The first commercial installation of the NOxOUT process is expected during 1988. Agreements to install several additional units in both Europe and the United States are currently under discussion. Wide use of the process by utilities and industry is expected as environmental regulations are promulgated and the technology is improved.

JEH;eh
3/9/88

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4. Muzio, L.J. and Arand, J.K., "Homogeneous Gas Phase Decomposition of Oxides of Nitrogen", EPRI Report No. FP-253, 1976.

5. Arand, J.K. and Muzio, L.J., "Urea Reduction of NOx in Combustion Effluents", U.S. Patent #4,208,386, 1980.

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10. Mansour, M.N., et al., "Full-Scale Evaluation of Urea Injection for NO Removal", 1987 Joint Symposium on Stationary Combustion NOx Control, New Orleans, LA.

EXCELLENT PERFORMANCE ACHIEVABLE

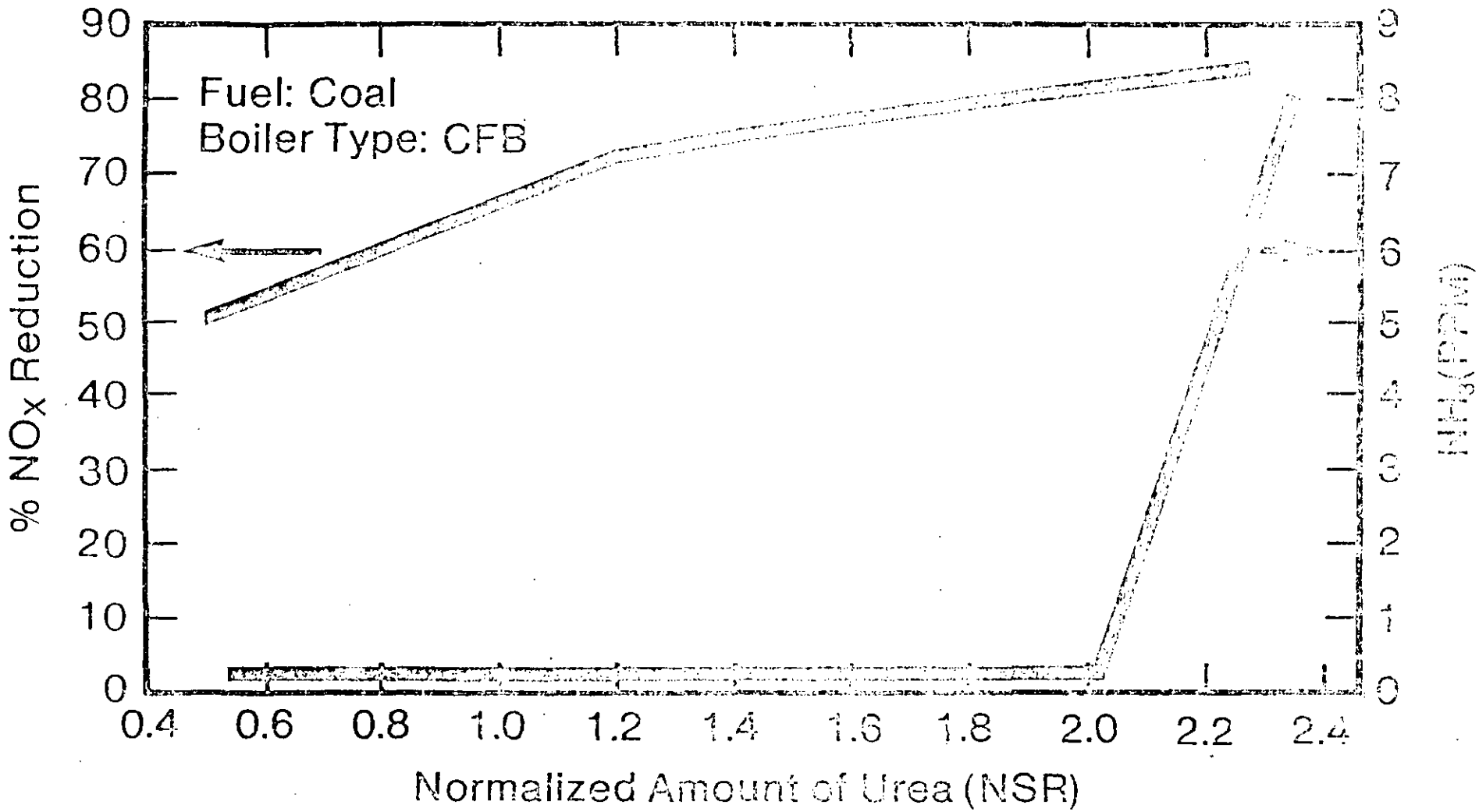


Figure 1

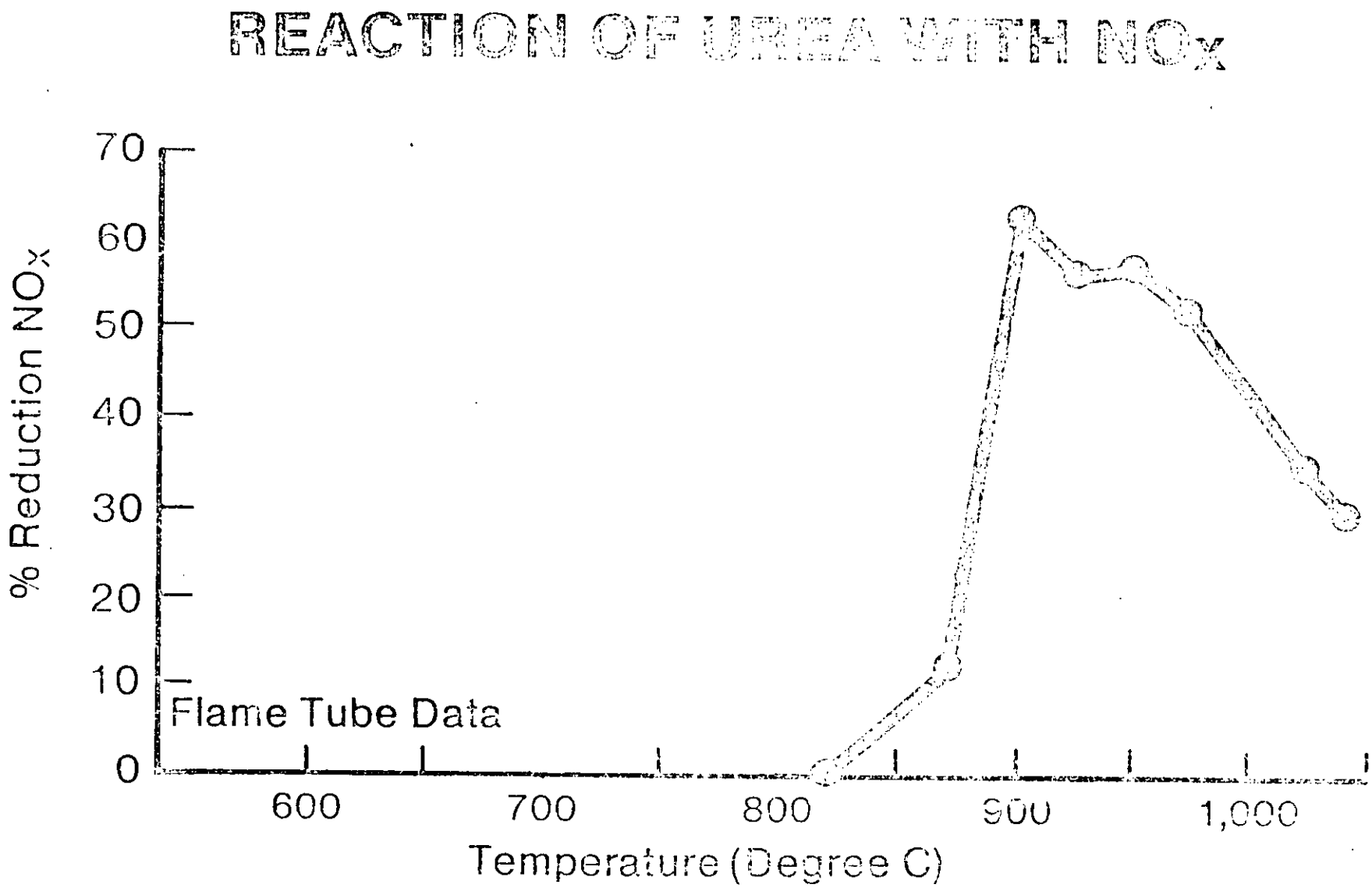

REACTION OF UREA WITH NOx
% Reduction NOx
70
60
50
40
30
20
10
0
Flame Tube Data
600
700
800
900
1,000
Temperature (Degree C)

Figure 2

PROCESS CHEMICALS EXTEND TEMPERATURE RANGE

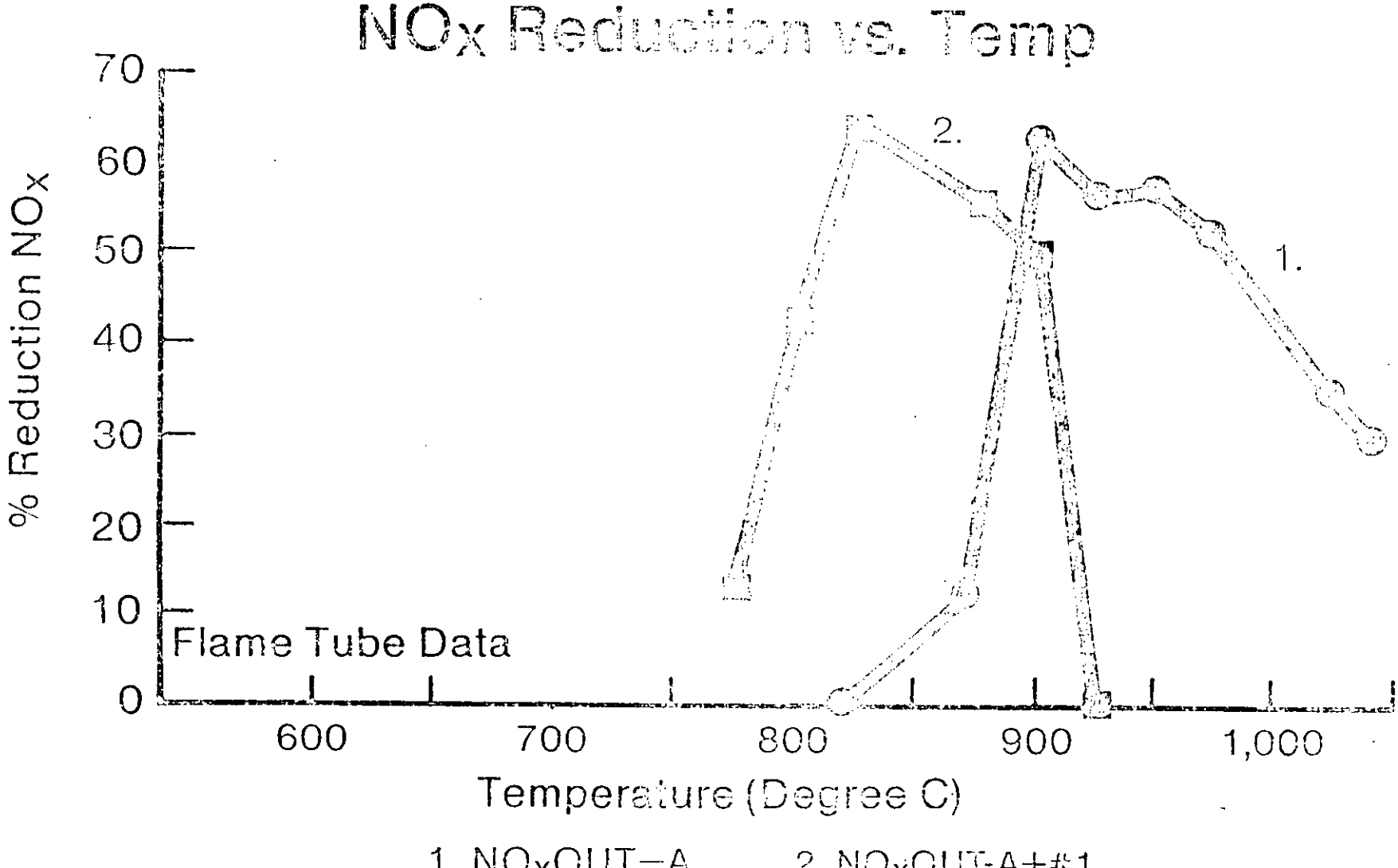
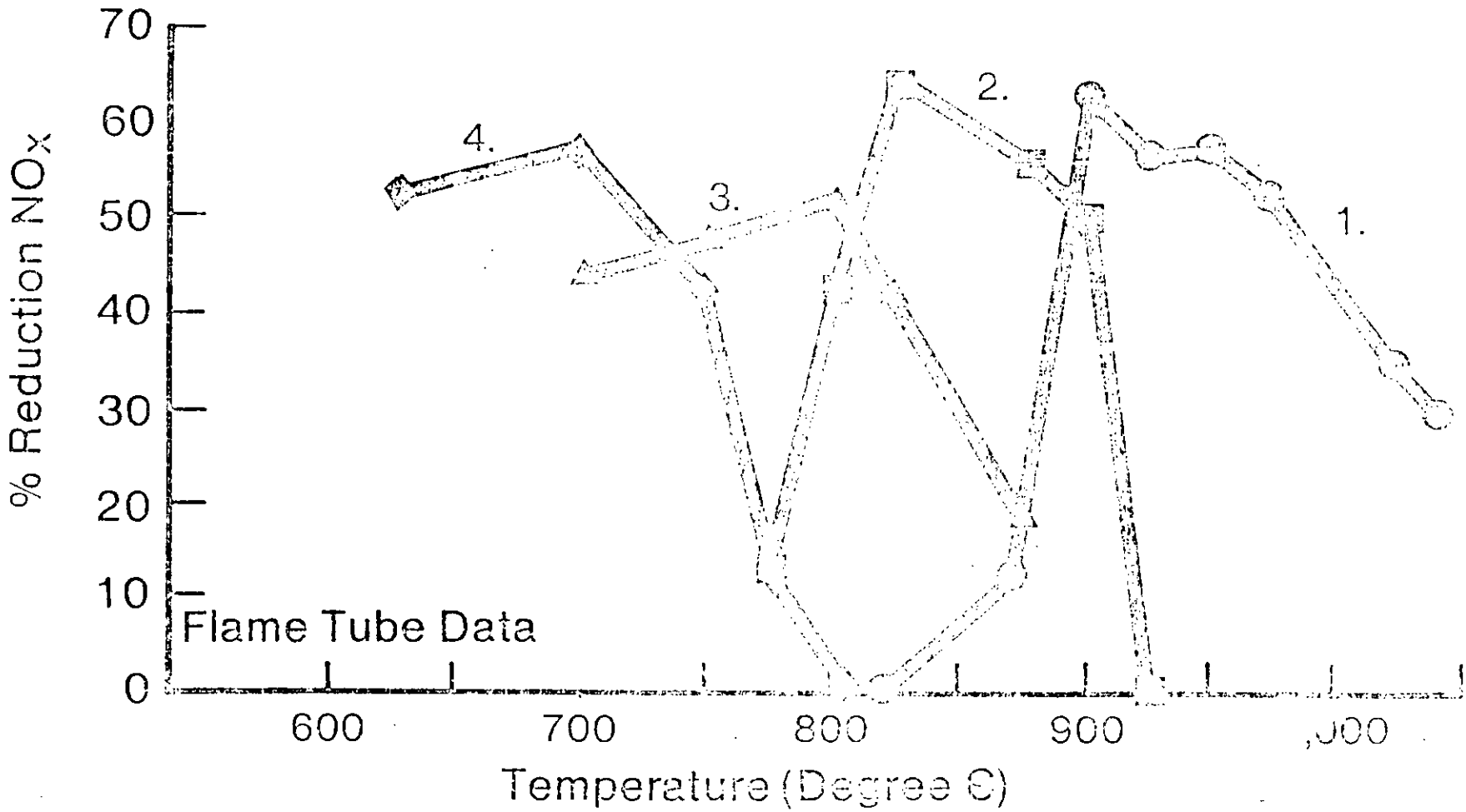


Figure 3

PROCESS CHEMICALS EXTEND TEMPERATURE RANGE



1. NO_xOUT—A 2. NO_xOUT-A+#1 3. #35 4. #1

Figure 4

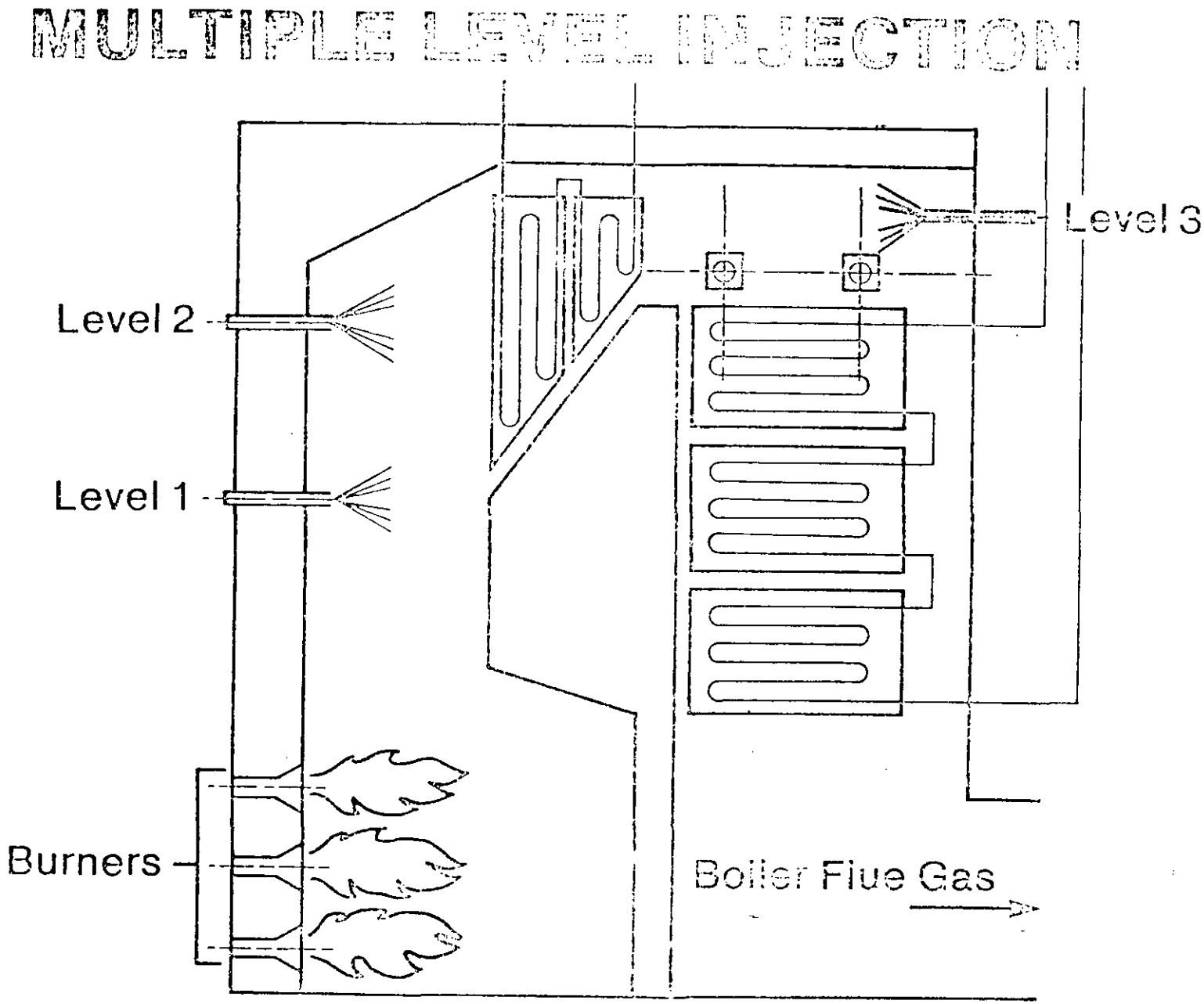

MULTIPLE LEVEL INJECTION
Level 3
Level 2
Level 1
Burners
Boiler Flue Gas

Figure 5

TWO LEVEL INJECTION INCREASES EFFECTIVENESS

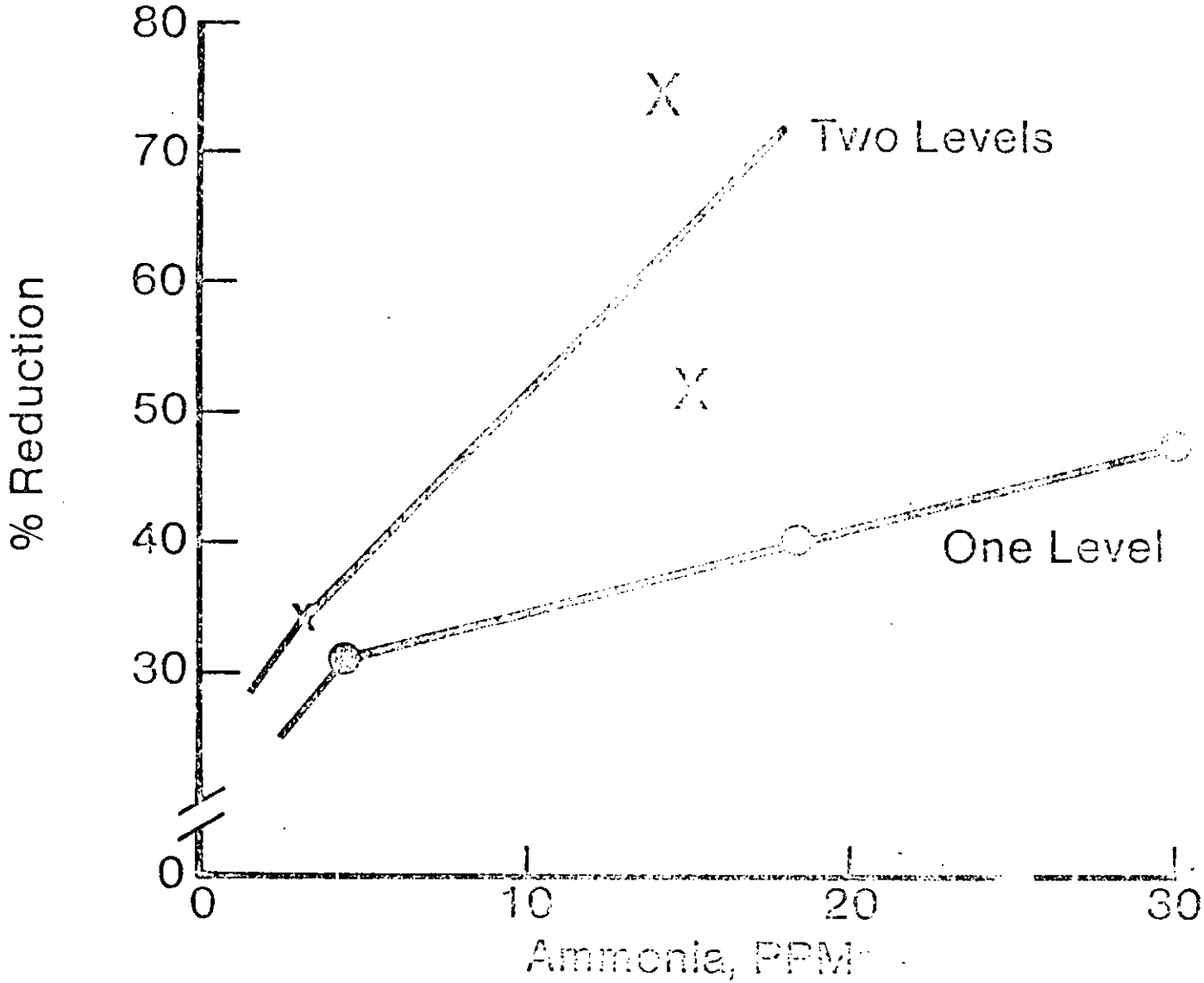


Figure 6

CONTROL OF NH_3 BREAKTHROUGH

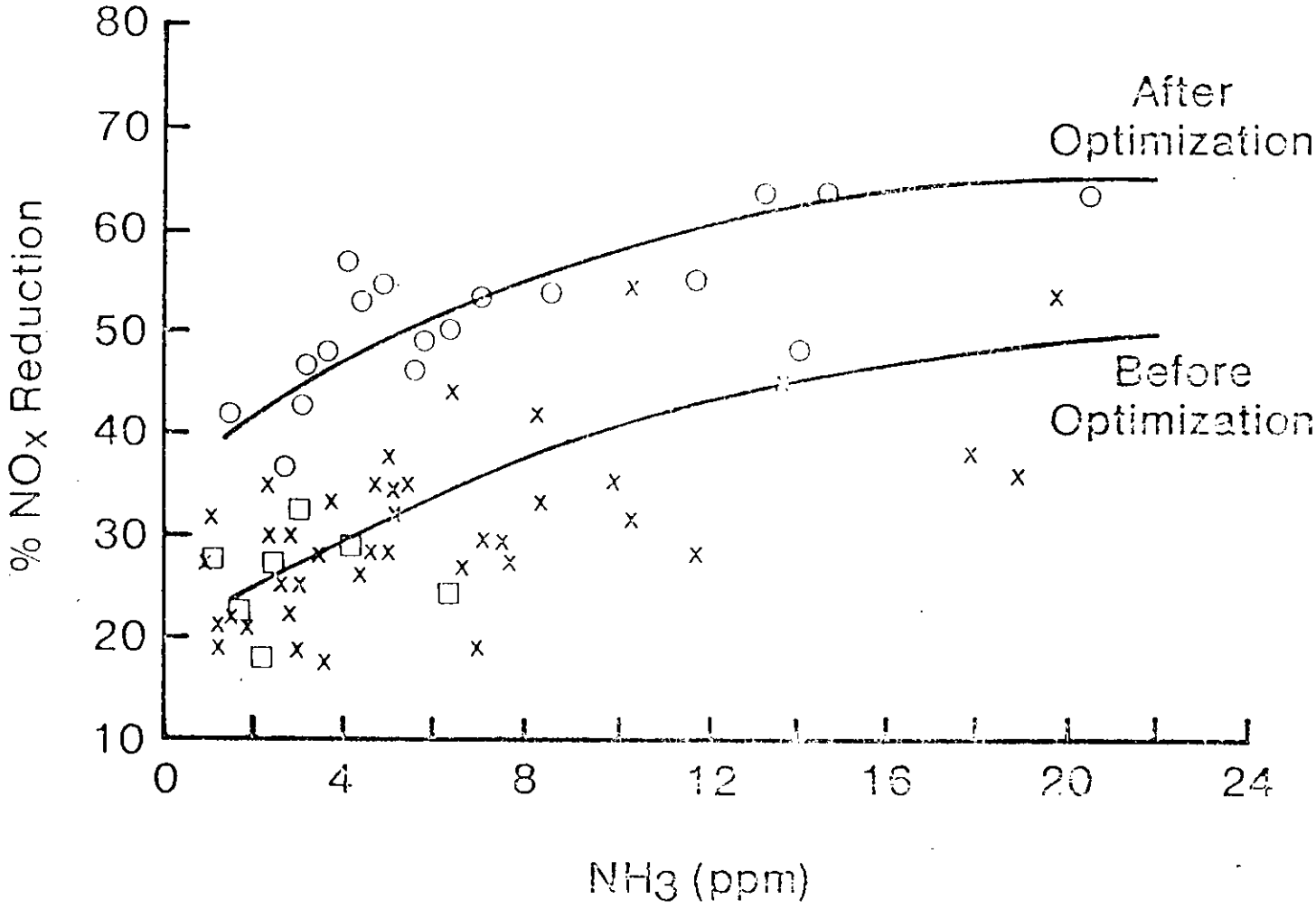
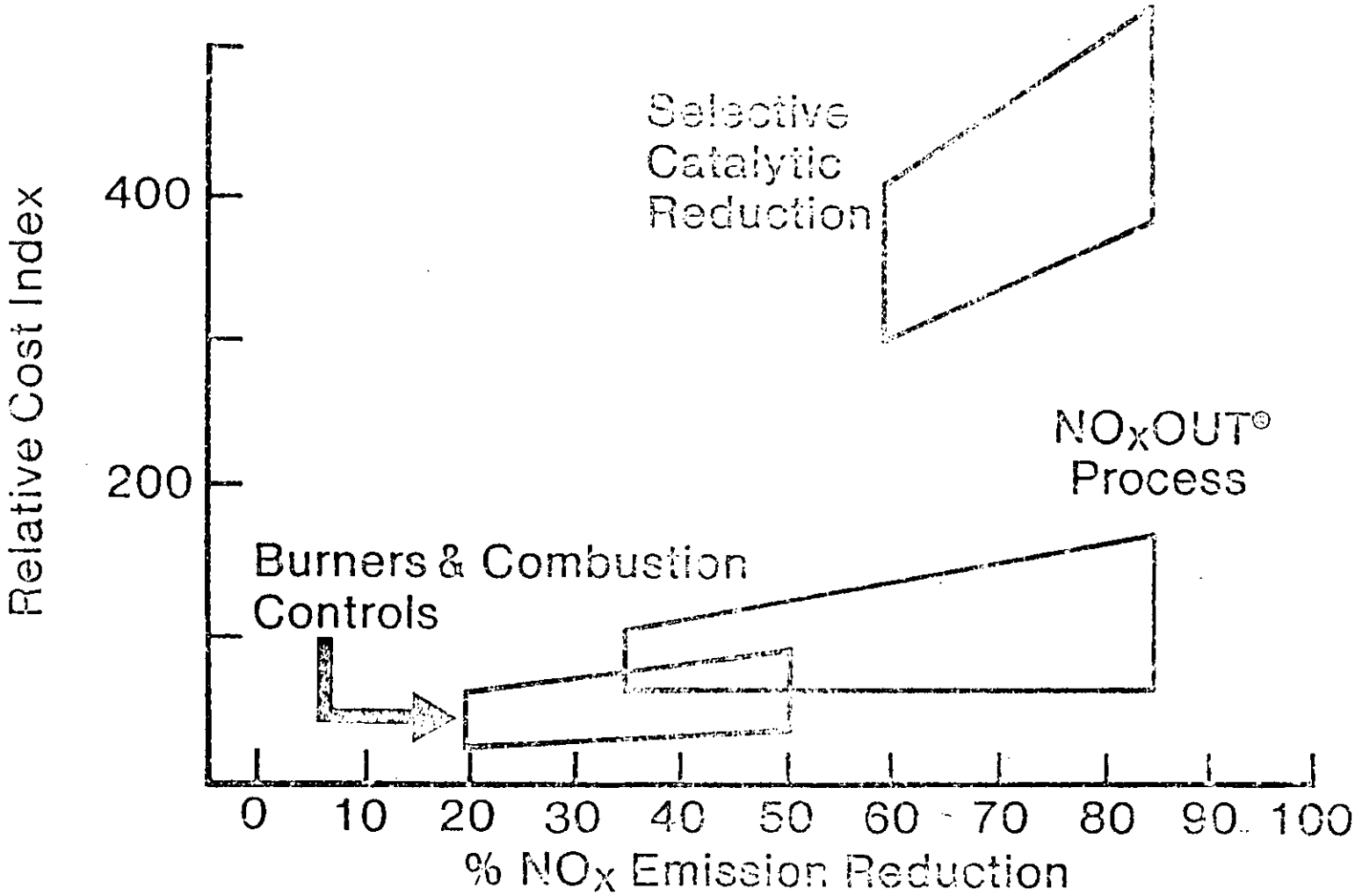


Figure 7

NO_x EMISSION CONTROL TECHNOLOGIES
Relative Cost Effectiveness



300 MW(e) Coal-Fired Boiler Retrofit in U.S.

Figure 8

PERFORMANCE IN COAL-FIRED UTILITY BOILERS

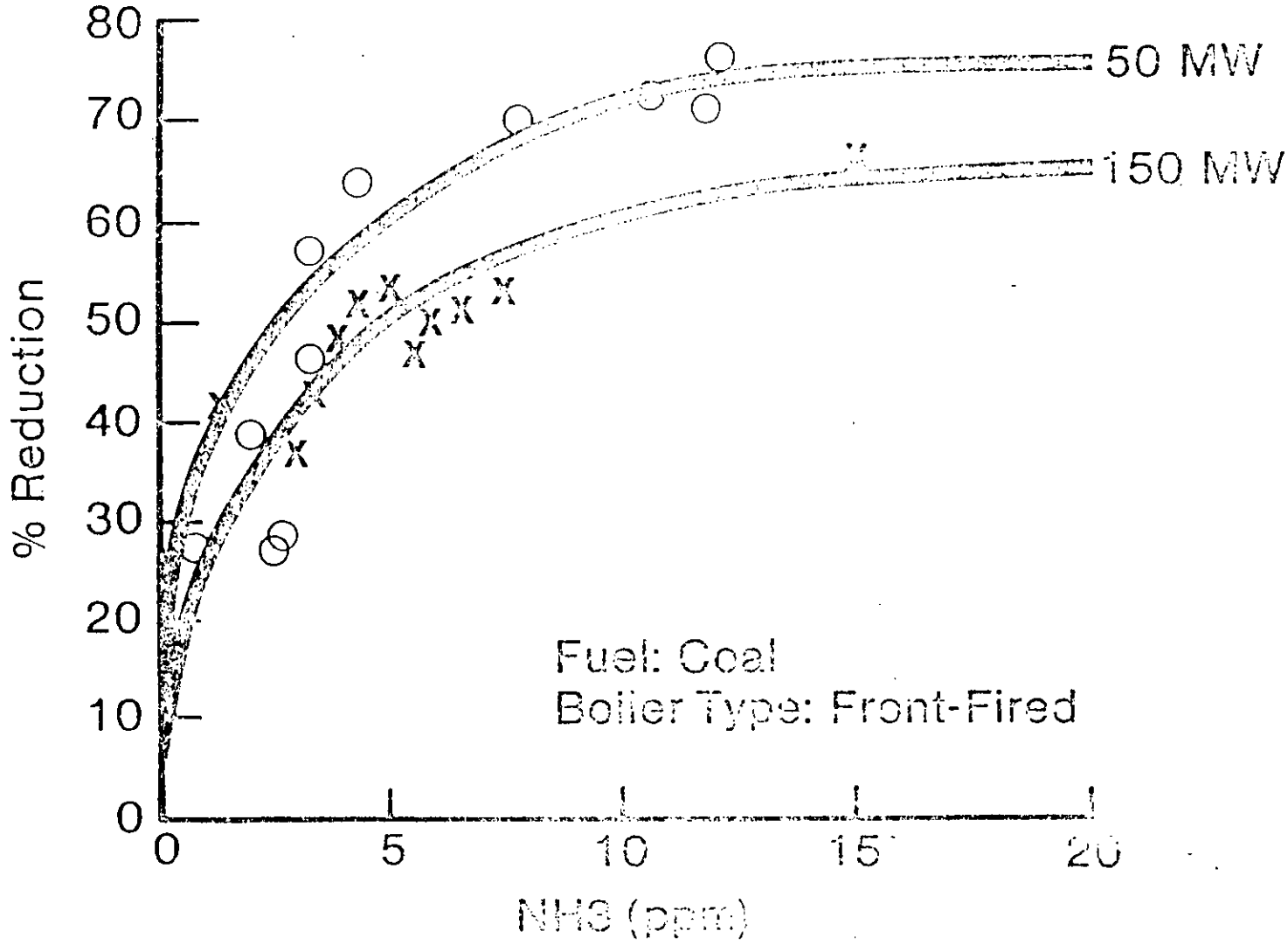


Figure 9

SUMMARY OF DEMONSTRATIONS

Boiler Type	Circulating Fluidized Bed				Moving Grate
Size (MW)	12	1 (th)	.4 (th)	.75 (th)	15
Fuel	Bit. Coal	Wood Waste	Coal	Low-Sulfur Coal	Municipal Solid Waste
°F	1600	1575-1650	1450-1600	1400-1500	1200-1800
% NOx Removed	88	60	65	67	68

Boiler Type	Pulverized Coal				
	Test Unit	Front-Fired	Corner-Fired	Front-Fired	
Size (MW)	.5 (th)	50	150	110	850
Fuel	Brown Coal	Bit. Coal	Brown Coal	Nat. Gas #6 Oil	#6 Oil
°F	1560-1850	1300-2000	1200-2100	1600-1900	1300-1[illegible]
% NOx Removed	85	83	70	Gas - 45 Oil - 70	35

(th) = Thermal

RECEIVED
DER - MAIL ROOM
1989 JAN 13 PM 1:12

January 11, 1989
88069

Mr. C. H. Fancy, P.E. Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Tropicana Cogeneration Project - AC 41-157745, PSD-FL-45 1021
Responses to Completeness Review

Dear Clair:

This correspondence is being submitted on behalf of Tropicana Products, Inc., to address the six questions raised in your letter dated December 28, 1988, regarding the subject project. Our responses are delineated below:

1. A $5,000.00 check payable to the Department for the Auxiliary Boiler permit fee is enclosed.

2. The latest two years of operational data for Boilers #2 - #5, #9 and #10 are submitted as Attachment 1. The operational data are for all boilers at the facility and individual statistics are not available. The estimated emissions from these boilers were based on their percentage of maximum heat input listed in Table 2-1, i.e., about 90%. The Box Plant Boiler, Sanitary Steam Boiler and Propane Vaporizer would still be operated.

   For 1986 the estimated emissions from the sources that will be shutdown are based on 509 x $10^6/ft^3$ of natural gas usage: PM = 1.3 TPY; SO_2 = 0.15 TPY; NO_x = 35.6 TPY; CO = 8.9 TPY; and VOC = 1.5 TPY. These estimates were made on the same basis as those for 1987 (see Tables 2-1 and 3-3 in the PSD Permit Application). The average of the 1986 and 1987 emission reductions are contained in the revised Table 3-3a, which is attached. Please note that the PM and PM_{10} emissions from the gas turbine have been lowered to reflect recent manufacturer information. GE estimates that the PM emissions will be less than 1 lb/hr. To reflect this estimate it was assumed that the gas turbine would emit no more than 1.5 lb/hr or 6.6 TPY (1.5 lb/hr x 8,760 hours/yr/2,000 tons/lb = 6.6 TPY). Table 3-3a presents the revised PSD applicability analysis which indicates no changes in applicability from the original permit submittal.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
P.O. Box 14288 5700 SW 34th Street Gainesville, FL 32604 904/375-8000 Telex: 984689 KBN ENG UD

3. The Auxiliary Boiler will be manufactured by Babcock & Wilcox. Information on the Auxiliary Boiler, as well as the Heat Recovery Steam Generator and Duct Burners, is contained in Attachment 2.

4. The estimated toxic emissions from the proposed project are contained in Attachment 3. These quantities of toxic emissions are extremely small and reflect the minute amounts contained in the fuel. For this project, the use of clean fuels, i.e., natural gas and distillate fuel oil, is the proposed control technology to minimize potentially toxic emissions.

5. We have further reviewed potential control technologies for the Auxiliary Boiler. Based on this review we propose emission limits of 0.1 lb $NO_x/10^6$ Btu heat input of natural gas and 0.2 lb $NO_x/10^6$ Btu heat input of distillate oil. The control technology will be flue gas recirculation. Attachment 4 presents additional information on this technology. The cost effectiveness of this technology is about $110 per ton of NO_x removed. Other feasible alternatives identified (see response to Question 6) have a much greater cost.

6. Attachment 5 presents additional information on the control technologies listed in the December 28, 1988 letter.

Please call if you have any questions.

Sincerely,

David A. Buff for

Kennard F. Kosky, P.E.
Project Manager

cc: Mr. Griscom Bettle, III
Mr. Scobee Woolwine, P.E.
Mr. William Sedlock, P.E.

copied: P. Raval
B. Andrews
J. Rogers
M. Aronson, EPA
B. Thomas, SW Dist.

ATTACHMENT 1

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

SOUTHWEST DISTRICT
7601 HIGHWAY 301 NORTH
TAMPA, FLORIDA 33610-9544

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

RICHARD D. GARRITY, PH.D.
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1986 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: TROPICANA PRODUCTS INC
2. Permit Number: AO 41-89688
3. Source Address: 1001 13 AVE E. BRADENTON, FL 33508
4. Description of Source: BOILERS (STEAM GENERATORS)

II ACTUAL OPERATING HOURS: 20 hrs/day 5.5 days/wk 52 wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
STEAM GENERATORS ONLY	N.A. tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

STEAM GENERATORS ONLY	N.A.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

SOUTHWEST DISTRICT
4520 OAK FAIR BLVD.
TAMPA, FLORIDA 33610-7347
813-623-5561
Suncom-552-7812

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
DR. RICHARD D. GARRITY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1987 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: TROPICANA PRODUCTS, INC.
2. Permit Number: A041-89684
3. Source Address: 1001 13TH AV. E., BRADENTON, FL 34206
4. Description of Source: STEAM GENERATING BOILERS

I ACTUAL OPERATING HOURS: 20 hrs/day 5.5 days/wk 52 wks/yr

II RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight	
STEAM GENERATORS ONLY	N/A	tons/yr
		tons/yr
		tons/yr
		tons/yr
		tons/yr

V PRODUCT OUTPUT (Specify applicable units)

STEAM GENERATORS ONLY

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

556	10^6 cubic feet Natural Gas	0	10^3 Kerosene
0	10^3 gallons _____ Oil, _____ %S	0	tons Coal
0	10^3 gallons Propane	0	tons Carbonaceous
0	10^6 Black Liquor Solids	0	tons Refuse

Other (Specify type and units) 0

EMISSION RATE(S) (tons/yr)

N/A Particulates	N/A Sulfur Dioxide	N/A Total Reduced Sulfur
N/A Nitrogen Oxide	N/A Carbon Monoxide	N/A Fluoride
N/A Hydrocarbon	Other (Specify type and units) PASSED VISIBLE EMISSIONS	

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

2-25-88
DATE

Gordon D. Hartman, Director, Env. Mgt.
TYPED NAME AND TITLE

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

509	10^6 cubic feet Natural Gas	6	10^3 Kerosene
0	10^3 gallons ~ Oil, ~ %S	0	tons Coal
0	10^3 gallons Propane	0	tons Carbonaceous
0	10^6 Black Liquor Solids	0	tons Refuse

Other (Specify type and units) 0

EMISSION RATE(S) (tons/yr)

N.A.	Particulates	N.A.	Sulfur Dioxide	N.A.	Total Reduced Sulfur
N.A.	Nitrogen Oxide	N.A.	Carbon Monoxide	N.A.	Fluoride
N.A.	Hydrocarbon	Other (Specify type and units) PASSED VISIBLE EMISSIONS			

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N.A.

CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

David O. Hamrick

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

David O. Hamrick, Sr. Vice President

TYPED NAME AND TITLE

February 13, 1987

DATE

Table 3-3a. PSD Source Applicability Analysis - Tropicana Cogeneration Project

Sources	Annual Emissions (TPY)					
	NOx	PM	PM10+	SO2	CO	VOC
Proposed:						
Gas Turbine	274.3	6.6	6.6	1.1	35.8	15.9
HRSG	39.9	0.9	0.9	0.2	55.8	15.9
Aux. Boiler	80.3	7.0	4.2	34.3	86.9	8.3
Subtotal	394.5	14.5	11.7	35.6	178.5	40.1
Shutdown:						
Existing Boilers*	33.6	1.2	1.2	0.1	8.4	1.4
Net Increase:	360.9	13.3	10.5	35.5	170.1	38.7
Significant Emission Rate:	40	25	15	40	100	40

* Boilers #2 - #5, #9 and #10 will be shutdown. These boilers represent 90% of the total boiler emissions (based on heat input; see Table 2-1).

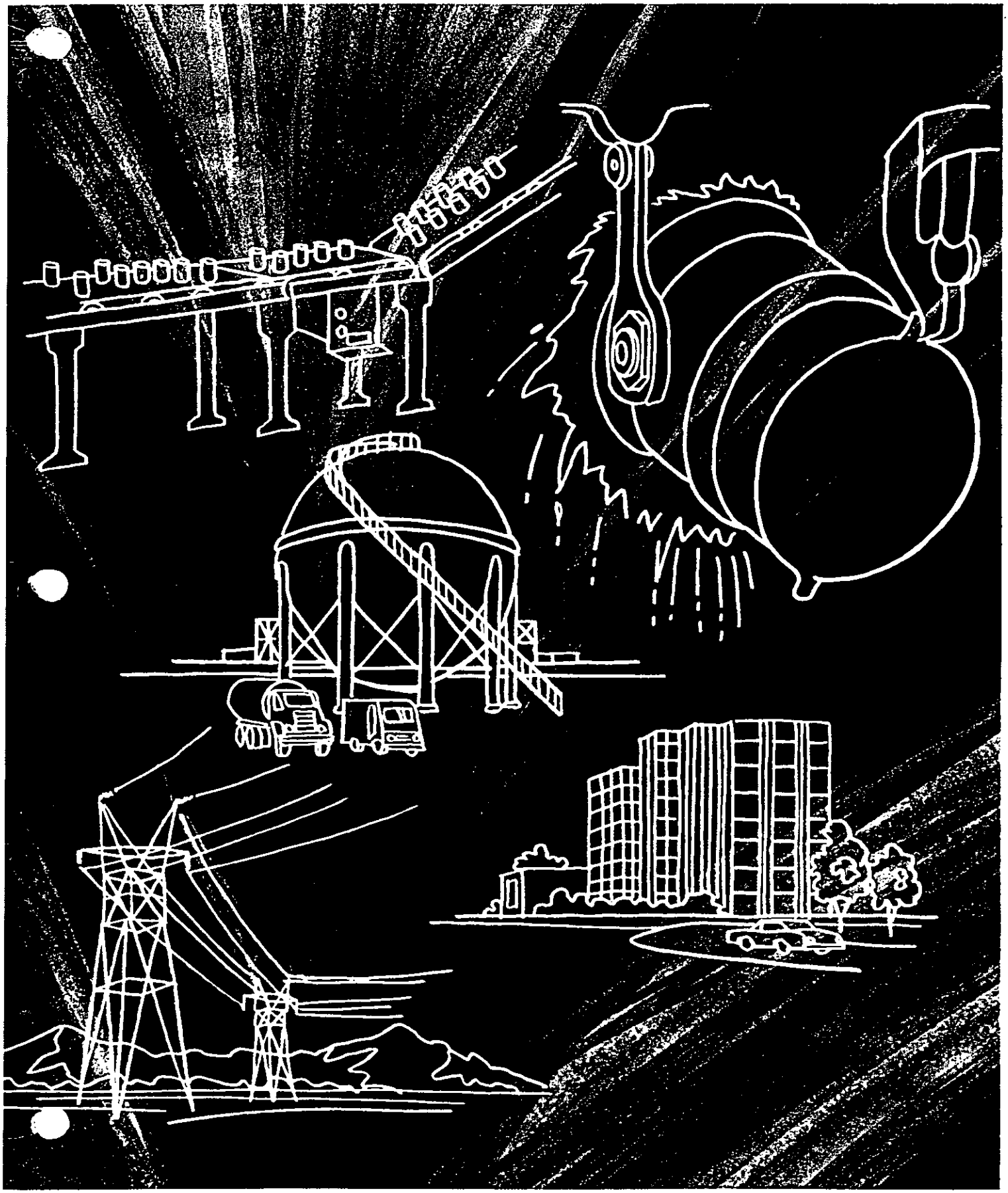
+ PM_{10} emissions from natural gas are assumed equal to PM emissions; PM_{10} emissions are 50% of PM emissions for industrial boilers firing distillate oil.

Note: Refer to Appendix C for emission calculations

ATTACHMENT 2

a McDermott company

Babcock & Wilcox



FM Package Boilers

FM is a proven design for dependable and economical steam production.

For over 114 years, B&W has been the leader in innovative, quality steam generating equipment for both industrial and central station applications. The modern FM package is no break with tradition. It continues to incorporate all the latest advances in boiler, burner and control design. And these major components are especially designed and manufactured by B&W to complement each other in operation.

Since 1950, B&W has pioneered shop-assembled boilers for oil and gas firing. As experience was gained, capacities, temperatures and pressures were increased. B&W's industrial boiler product development continues to be concentrated on the FM. The current FM, with its high efficiency, low maintenance and simple operation, has replaced earlier field-erected designs. Capacities are available to 180,000 lb/hr, temperatures to 825F, and design pressures to 1050 psig.

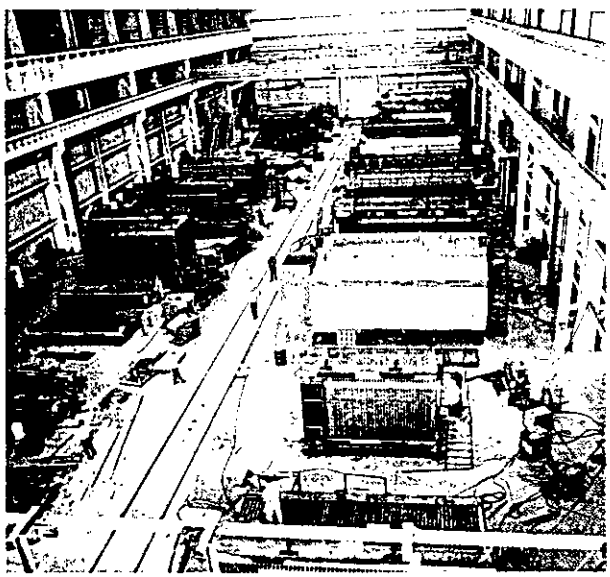
Continuing research and development results are fed to FM design and field engineers charged with the responsibility of maintaining the FM as the best package boiler buy. Over 3200 operating units have earned an outstanding reputation for reliability and performance. And the research goes on.

Service.

You'll need only one service engineer — one B&W service engineer — to get your FM package steaming and keep it steaming.

B&W makes all the major components in the FM package: boiler, burner and controls — plus the sootblowers. Therefore, we can take full and total responsibility for the complete package. No sub-contractors to sub-divide responsibility. No buck-passing because there's no one else to pass the buck to. What our service engineer does pass on to you is steam generation know-how.

Once the unit arrives at your plant, the B&W service engineer will be available for consultation during startup of the complete package. And he'll train your personnel to operate it so you get the most out of your investment. Our follow-up inspection and maintenance service insure continued efficient steam generation.



Over 700 skilled craftsmen, each with an average of 13 years specialized boiler experience, fabricate many units simultaneously. B&W's Wilmington, North Carolina, works —designed for quality control and efficiency — is located near road, water and rail transportation facilities. The completed unit is delivered to you, ready for piping.

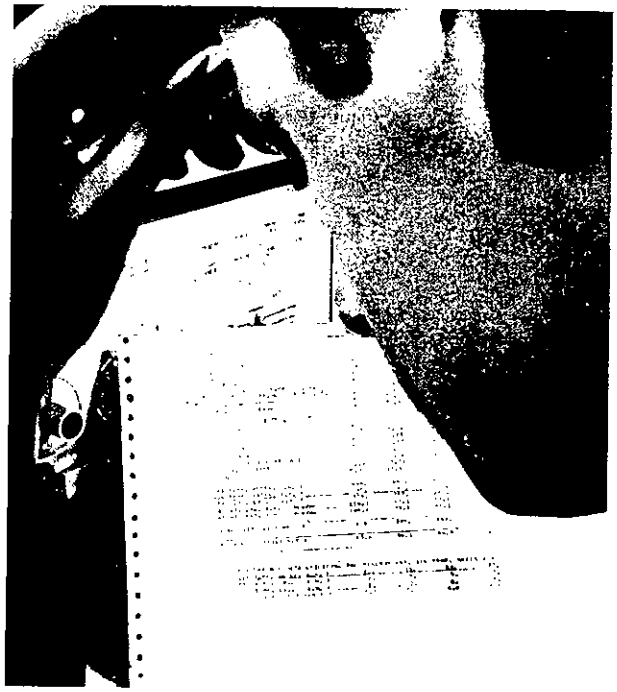
B&W's single responsibility service is available throughout the U.S.

Computer program.

Now a computer program is available to help you find the package boiler combination that's right for your requirements.

Call your B&W sales engineer. Tell him what your fuels are. How many pounds of steam you need. How soon you need it. What your future needs might be. He'll have your requirements processed through our computer.

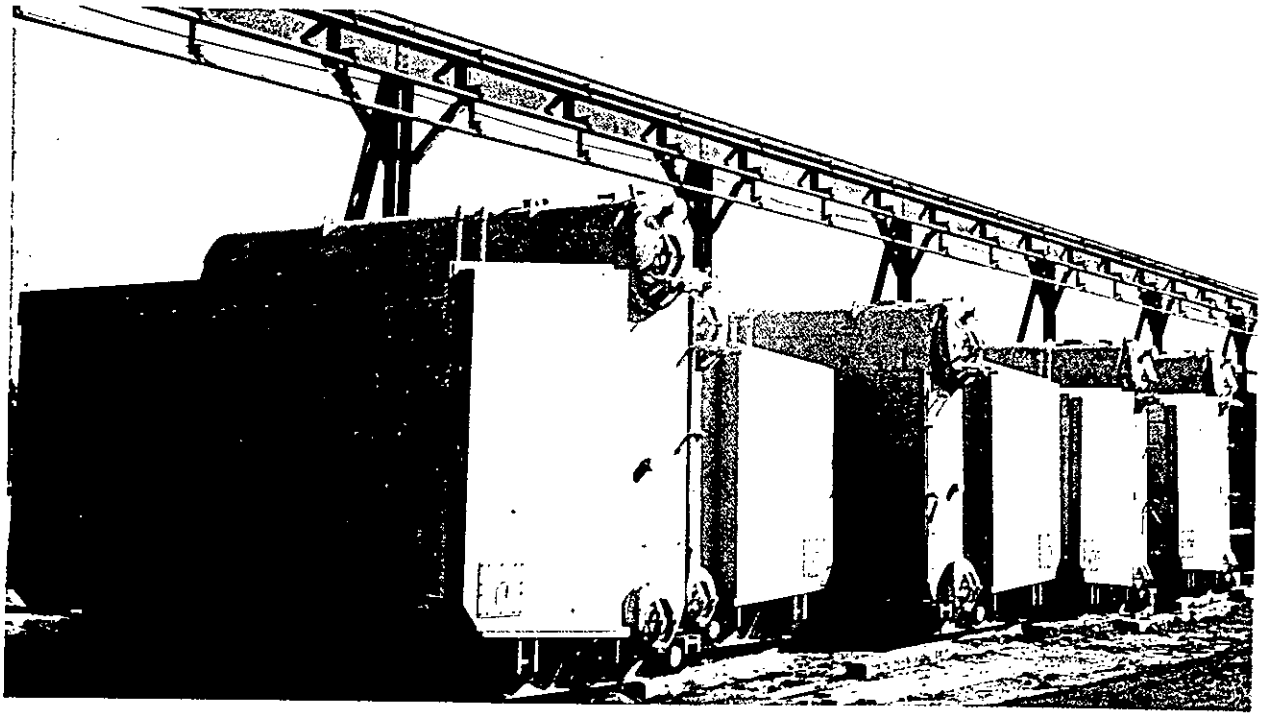
He'll have full technical and price data promptly for you on the most economic combination of package boiler equipment. And he'll give you the alternatives. Different numbers and sizes of boilers, fuel combinations, heat traps and equipment arrangements. Plus a delivery date.



Computer program provides quick, accurate study of economic alternatives.

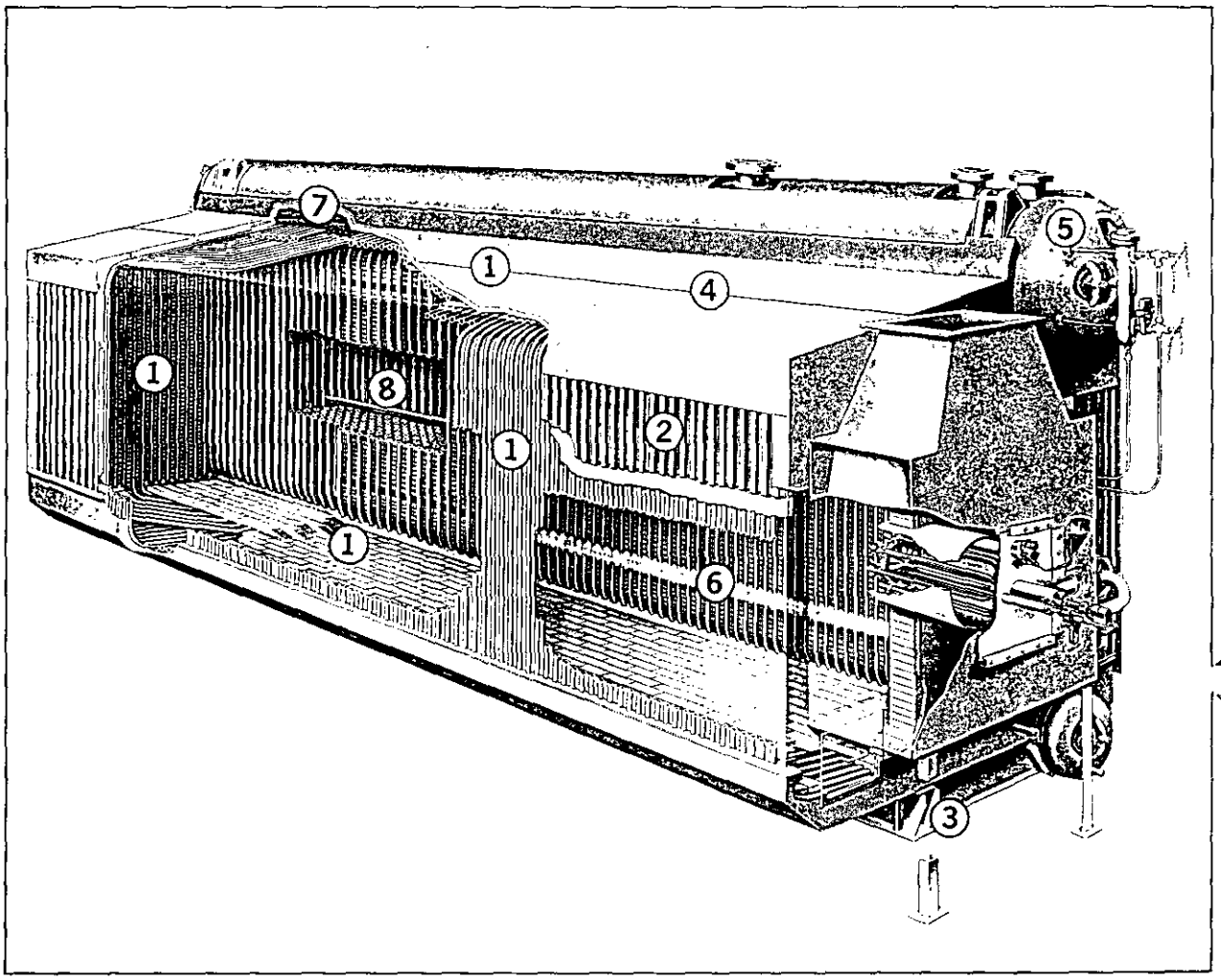
Shipment.

Because our FMs are the most widely accepted package boiler, we've instituted a manufacturing program that makes rapid shipment routine. The most popular size FMs are being built on a continuous basis, and are stocked awaiting your order. So they'll be ready for immediate shipment.



FMs stocked in Wilmington awaiting shipment.

Designed for reliable, efficient operation in a wide variety of industries.



Proven "D"-type construction with separate boiler and furnace sections features proper geometry of the burning chamber to increase combustion efficiency without impingement on walls.

1. Maximum furnace wall water-cooling including not only side walls, roof and floor, but high-duty rear wall as well — eliminates refractory and its attendant maintenance. This unique feature of the FM locates total water cooling where it is most needed and where it can contribute most to keeping maintenance costs down.

2. Gas-tight setting, inner skin casing or membrane — provides the gas-tight setting absolutely necessary on all package boilers. Both constructions eliminate dew-point sulfur corrosion and outage caused by gas leaks.

3. Rugged steel base frame supports the entire boiler. A concrete slab with no special saddles, supports or piers is all that's needed for the FM. Lifting lugs and jacking pads ease installation and relocation.

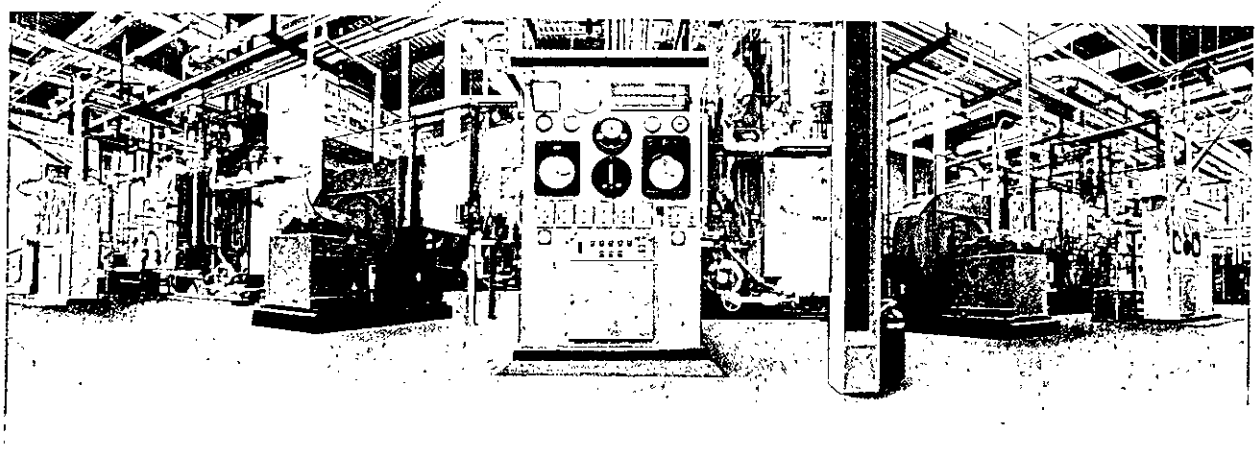
4. Outer steel lagging is attractive and water-tight for outdoor installations.

5. Drum internals provide high steam purity and insure positive circulation.

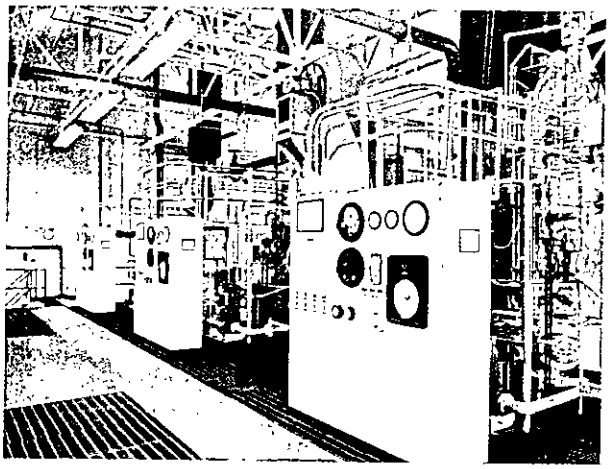
6. Tube bank access ports allow total observation and simplify water washing.

7. Grooved tube seats with polished tube ends provide maximum protection during initial handling and transportation as well as against leakage throughout the unit's life.

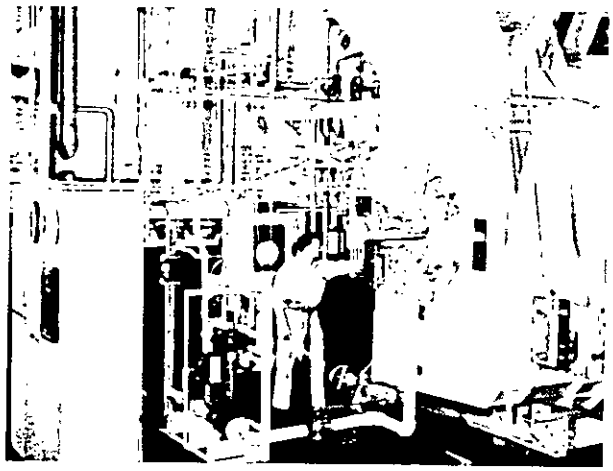
8. Sootblowers are properly located for effective convection bank cleaning.



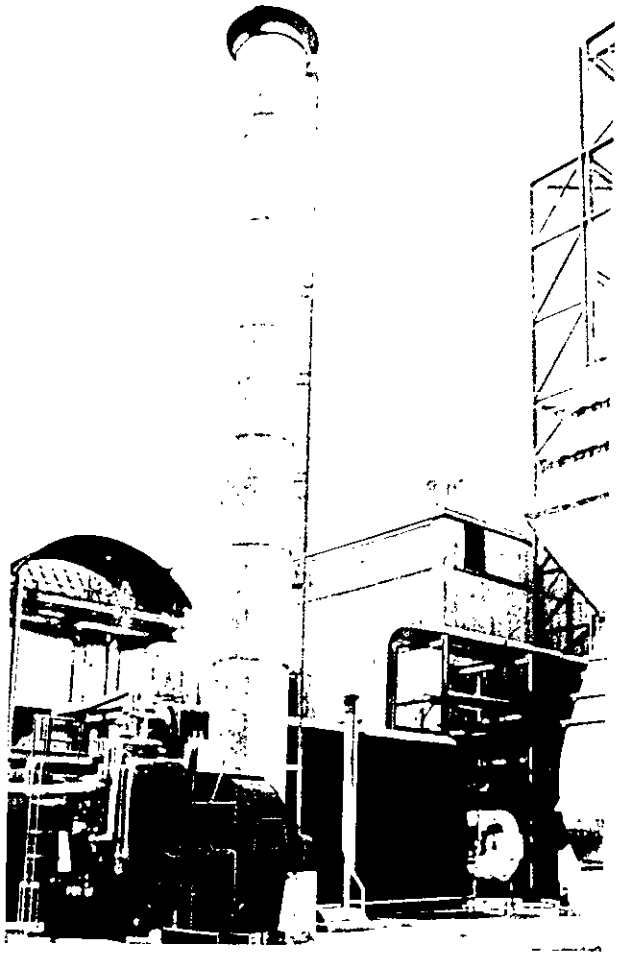
Panoramic view of three FMs installed in a major tire manufacturing facility.



Three-boiler installation in a prominent southern research center.



A standard FM package operating in a midwestern industrial complex.

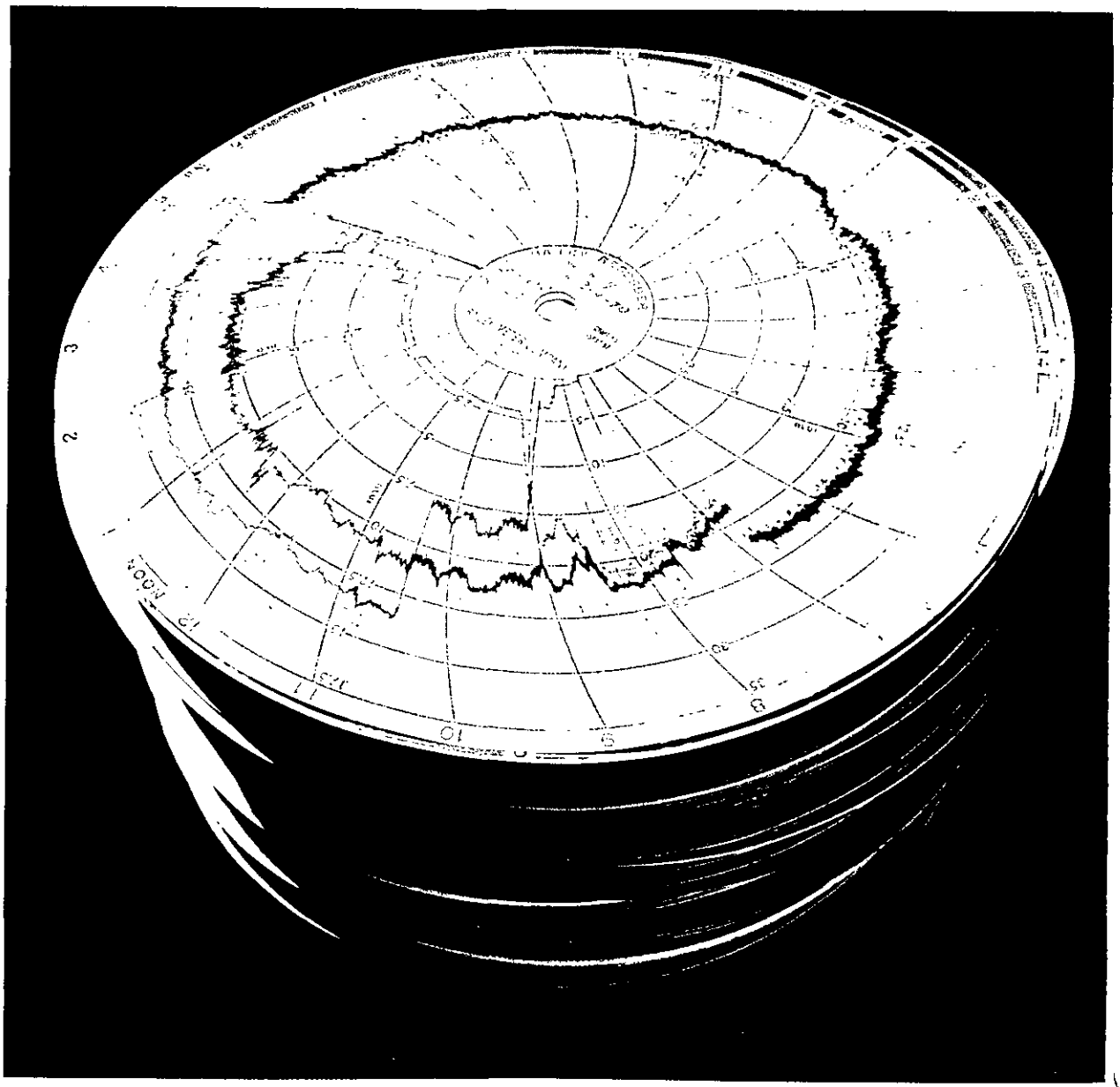


Installed outdoors, this FM provides a large B&W utility boiler with steam for start-up.

Efficient separation, positive circulation assure dependability.

Even when load changes are wide or frequent enough to affect water level in the drum, positive circulation is assured with B&W drum internals. As hot furnace flue gas crosses the first rows of tubes in the boiler bank, a considerable amount of steam is generated in this area. This quantity is substantially greater on higher capacity units for essentially the same drum length, imposing a tremendous burden on drum internals. B&W separation equipment is designed to effectively handle this rapid, intense generation.

Baffles direct portions of the steam to quieter zones of the drum, making use of the entire length of scrubbing elements to remove unwanted moisture droplets. These secondary scrubbers are placed high in the drum to take full advantage of

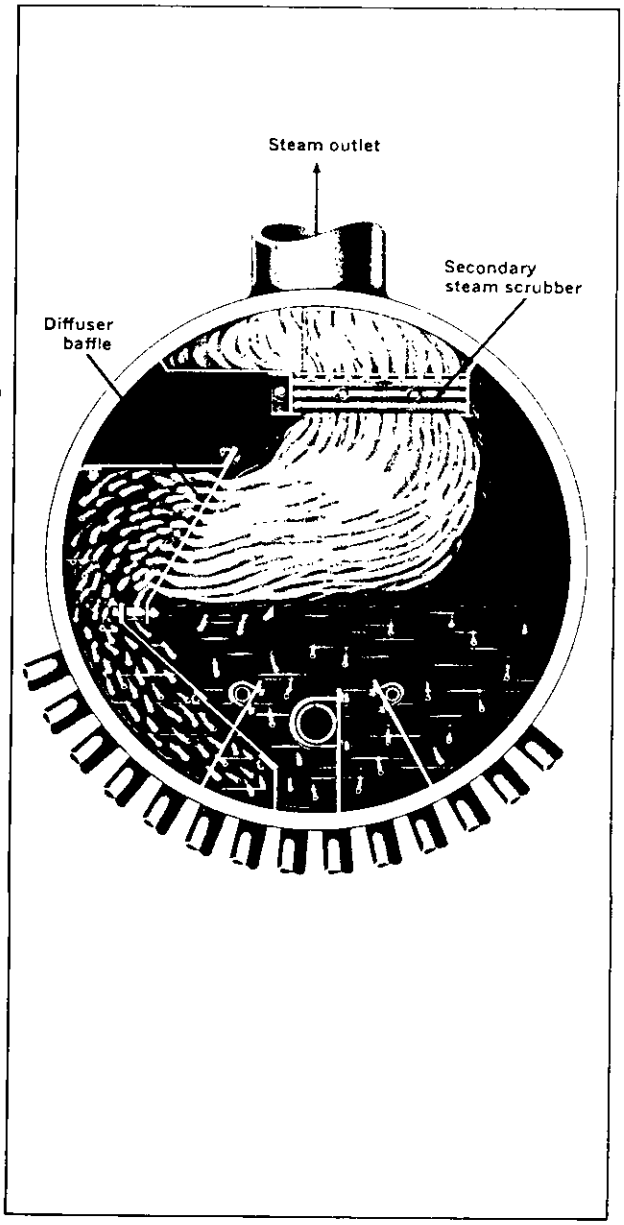


Steam flow charts.

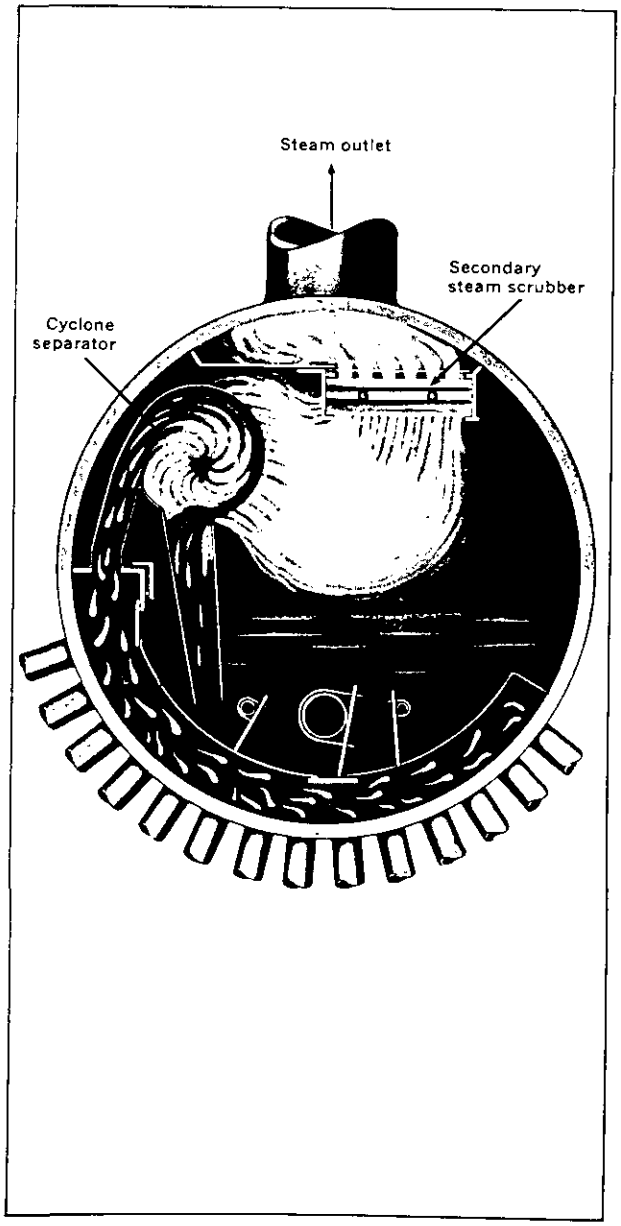
natural moisture separation.

When superheaters or special processes require, steam with less than 1 PPM solids can be obtained. Turbine blades are kept cleaner, and costly superheater tube failures are eliminated. An equally important ability designed into B&W's drum internals is the supply of bubble-free "solid" water back to the downcomer circuits for positive circulating head. Drum water end flow is also controlled to reduce turbulence.

Adequate slope is designed on all heat-absorbing surfaces so that steam bubbles, which cause tube failure, cannot form. All downcomers are located in the cooler zone of the convection bank for positive circulation. Each tube in the unit is completely drainable.



Type "B" baffles.



Horizontal cyclone steam separator.

Periodic inspection, maintenance made easy.

The FM boiler has been designed so operators and maintenance personnel can get at everything easily. But it's built so they shouldn't have to. The absence of headers on the FM eliminates the need for handhold openings. Complex inspection, gasket replacement and other bothersome procedures, therefore, are unnecessary.

Tube bank access ports.

Tube bank access ports with refractory knockout plugs are optional between all FM baffle wall tubes. These openings are located across both the top and the bottom of the boiler bank. Consequently, tubes and seats can be inspected by looking into these openings with a flashlight. Tube bank access ports also accommodate water-washing of the bank. The tube bank access ports thus provide for complete inspection and cleaning of the convection bank, a benefit lacking in most other designs.

Steam and lower drums are readily checked through manholes on both ends of the unit.

Refractory plugs over tube bank access ports are easily removed for periodic inspection of boiler bank.

Furnace, burner inspection.

The FM furnace is easily accessible through a large, bolted door in the front wall. It is not necessary to enter through the burner opening. Pressurized burner observation ports are provided in the side and rear walls of the furnace.

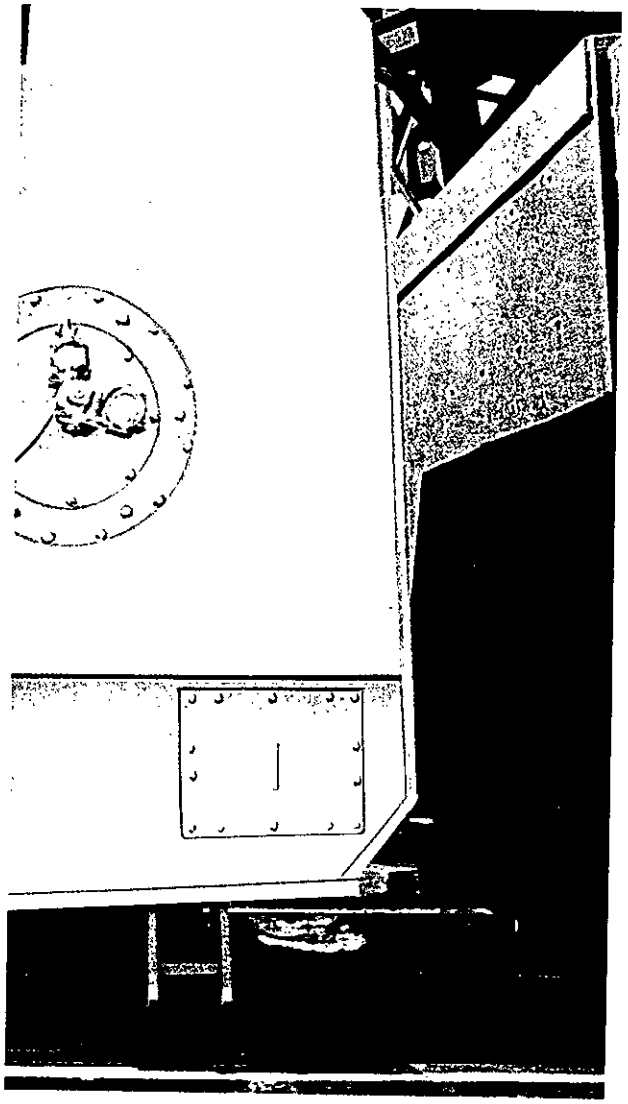
Water-wash troughs, drains.

Water introduced into the FM boiler convection bank through the inspection ports or sootblowers for cleaning is collected in water-wash troughs located on both sides of the lower drum along the length of the unit. Drain nipples at front and rear of the boiler relieve these troughs.

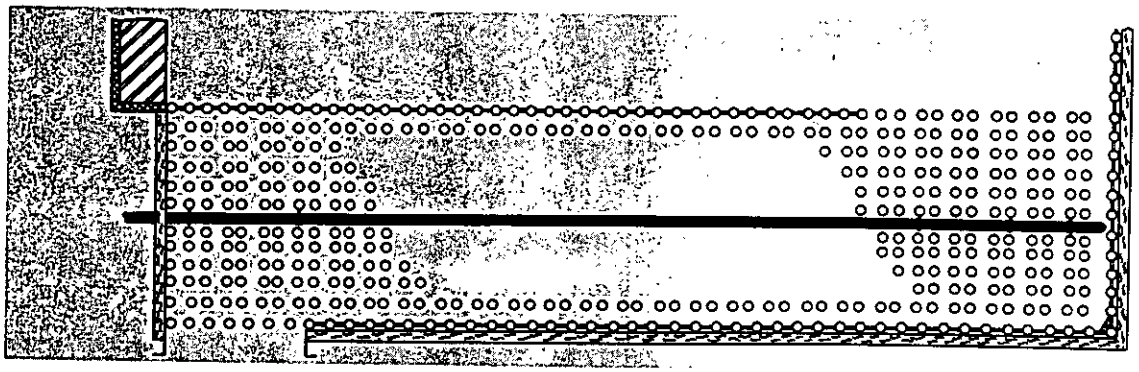
Boiler cleaning systems.

When fuel conditions dictate, B&W FMs are equipped with complete sootblowing systems including piping, valves and fittings. Blowing elements are positioned in the exact center of the boiler bank for optimum cleaning. Materials supplied for the blowers are based on anticipated service temperatures.

Typical of the importance attached to all components of the FM package are two features incorporated in the FM's sootblowing system — supplied by B&W subsidiary Diamond Power. Alternate hand dialoy C-type bearings, resistant to high temperature tube corrosion, are supplied in the high-gas temperature zone to minimize the possibility of failure and subsequent loss of blower support. In addition, seal air is introduced within the sootblowers to prevent sulfur-laden flue gas from entering the blowing elements.



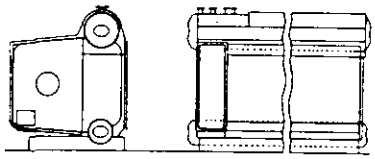
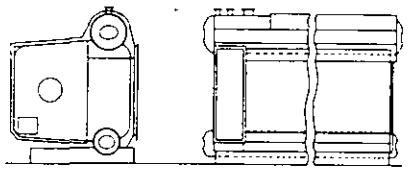
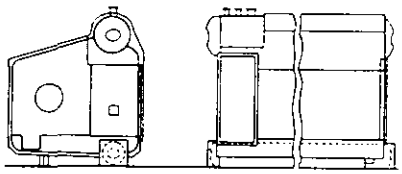
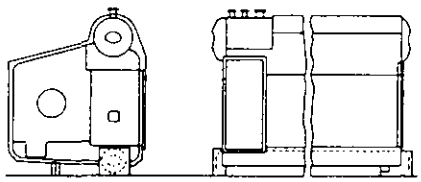
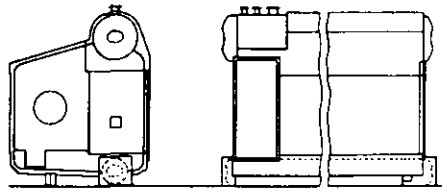
The furnace is easily accessible through large, bolted door on front wall.



The spacing of the boiler bank tubes — in the direction of gas flow — is alternately arranged wide and narrow to facilitate tube removal. Tubes are also arranged in-line for effective "lane-type" cleaning by rotating sootblowers.

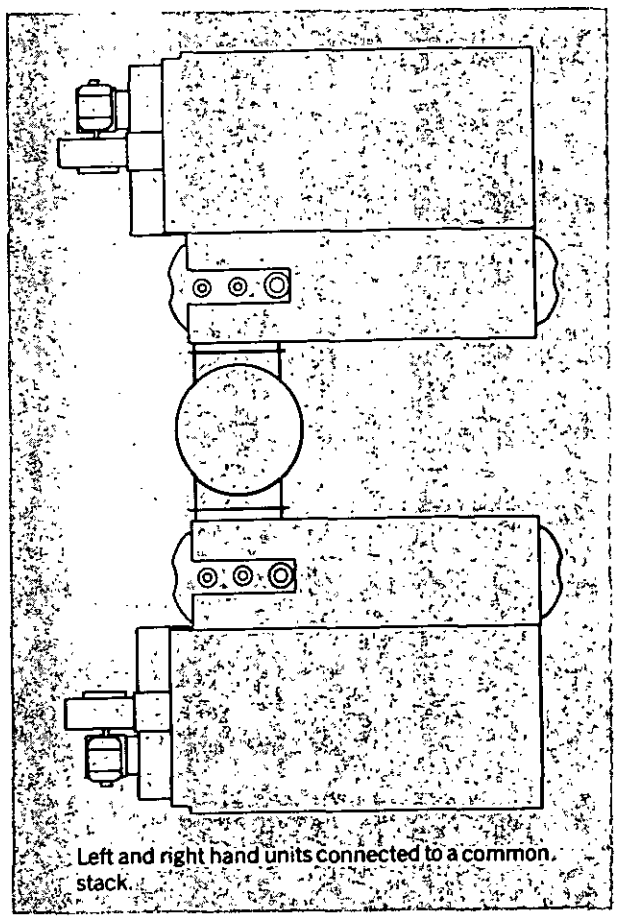
All 26 capacities measure up to the most demanding requirements.

The FM boiler is available in a wide range of capacities — from 8,200 to 180,000 lb/hr, from 250 to 1050 design pressure, and with steam temperatures to 825F — so you won't have to sacrifice the reliability of the FM because it's not available in the size you need. Of course, the B&W sales engineer will provide you with complete technical information. And our computer program will assist you in quickly specifying the most economic combination of equipment.

Scale 1′ = 1/16″	Boilers	Capacity Range* lb. per hour	Length	Width
	FM 9-22 26 30 34 39 43 48 52 57	8200 to 31,000	7′ 7″ 8′ 11″ 9′ 11″ 11′ 3″ 12′ 7″ 13′ 11″ 15′ 3″ 16′ 7″ 17′ 11″	10′ 2⅞″
	FM 10-52 57 61 66 70 79 88	35,000 to 70,000	16′ 7″ 17′ 11″ 19′ 3″ 20′ 7″ 21′ 11″ 24′ 7″ 27′ 3″	10′ [illegible]⅛″
	FM 103-70 79 88 97	70,000 to 100,000	21′ 3 3/16″ 23′ 11 3/16″ 26′ 7 3/16″ 29′ 11″	11′ 9″
	FM 106-79 88 97	100,000 to 130,000	23′ 11 3/16″ 26′ 7 3/16″ 29′ 3 3/16″	11′ 9″
	FM 117-88 97 FM 120-97	135,000 to 180,000	26′ 7 3/16″ 29′ 3 3/16″ 29′ 3 3/16″	11′ 11¼″ 12′ 5⅜″

Steam capacities shown are saturated steam. Capacities shown will vary depending on conditions and limitations.

Height	Windbox Depth		Drum Size
	Cold	Hot	
12' 4"	15"	30"	36" Steam Drum 24" Lower Drum
6"	30"	30"	36" Steam Drum 24" Lower Drum
13' 9¾"	42"	42"	42" Steam Drum 24" Lower Drum
14' 3"	42"	60"	48" Steam Drum 24" Lower Drum
15' 4½" 16' 10½"	60"	60"	48" Steam Drum 24" Lower Drum 54" Steam Drum 24" Lower Drum



Left and right hand units connected to a common stack.

Notes

1. FM 9 & 10 —skin cased for gas-tight operation.

   FM 103, 106, 117 & 120 —membrane wall construction provides our tightest setting, as units often operate at increased internal furnace pressure.

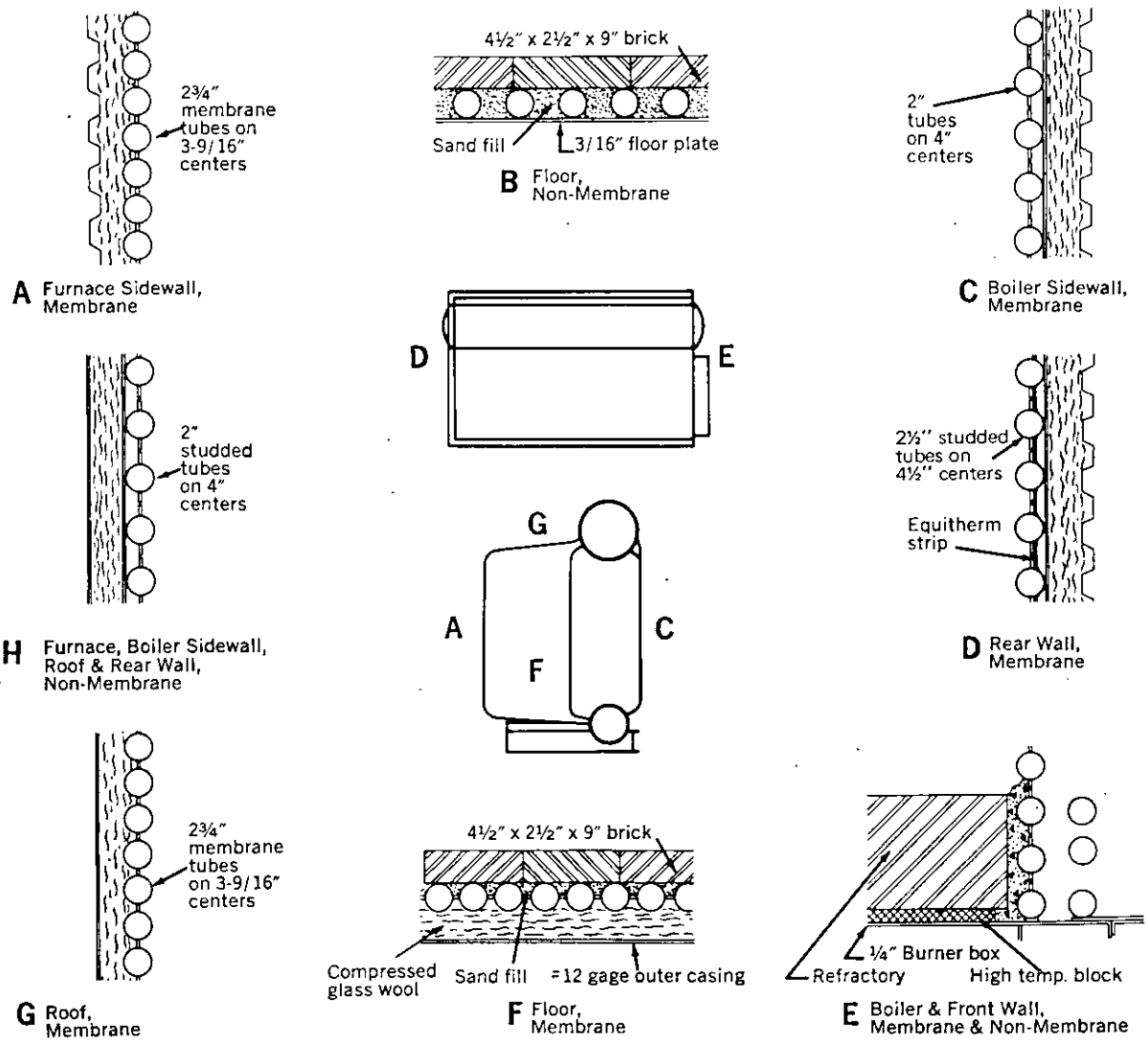
2. Because of the company's constant effort to improve design, equipment supplied may differ slightly in detail from that described in this publication.

Gas-tight setting increases reliability.

Smaller and intermediate size FMs (with lower internal furnace gas pressures) are completely enclosed in a 10-gauge, pressure-tight inner casing. In this construction, the inner casing is welded to 4 in. x 1/4 in. tie bars which, in turn, are strength-welded to furnace tubes. These tie bars are located at sufficiently close intervals from drum-to-drum so that the casing is held rigid against the tubes.

The inner casing eliminates corrosion that is caused by moisture condensation combining with sulfur in the flue gas. The casing temperature is close to that of saturated water in the tubes, so condensation cannot occur. Outer-casing designs corrode readily, and are susceptible to gas leaks and associated repair.

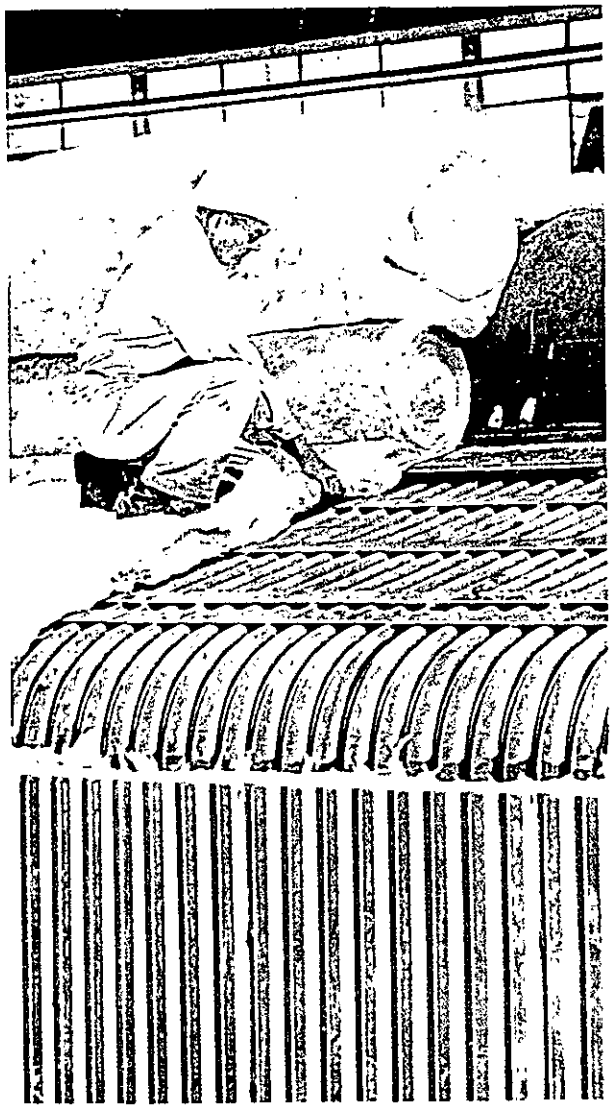
A 3-in. layer of high-temperature glass-blanket insulation is compressed to 2 in. between the inner casing and the outer lagging on units up to 700 psi. Units above 700 psi are insulated by a 4-in. layer compressed to 2-1/2 in. An insulation density of 1.62 and 1.73 pounds per cubic foot respectively assures a low heat conductivity and produces a cool outer lagging temperature. A 12-gauge water-tight lagging protects the insulation and is designed to permit expansion and contraction of various components during startup and shutdown.



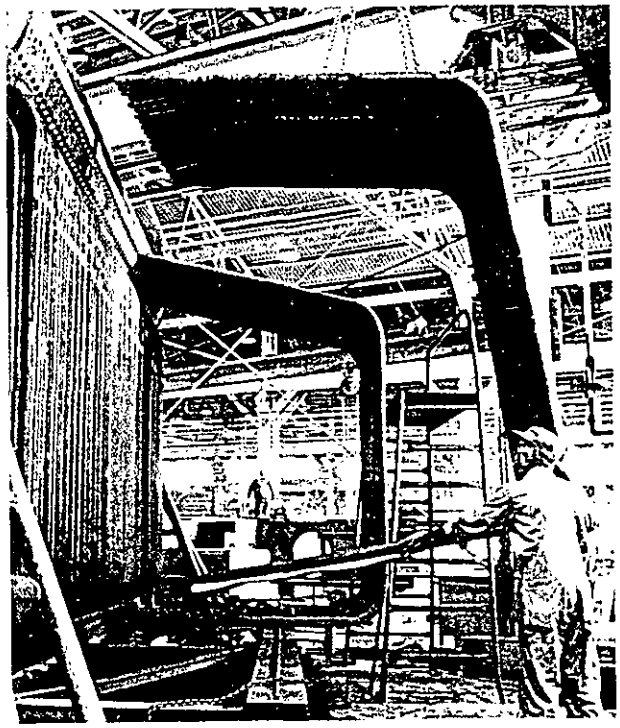
Wall construction details.

For FMs in the 103 series and larger, because of higher furnace pressures experienced, B&W's well known membrane wall setting design is furnished in place of inner skin casing. Membrane furnace walls, which are formed by continuously welding bars between adjacent tubes, provide the ultimate in a pressure-tight setting. Membrane wall construction is standard on the largest units.

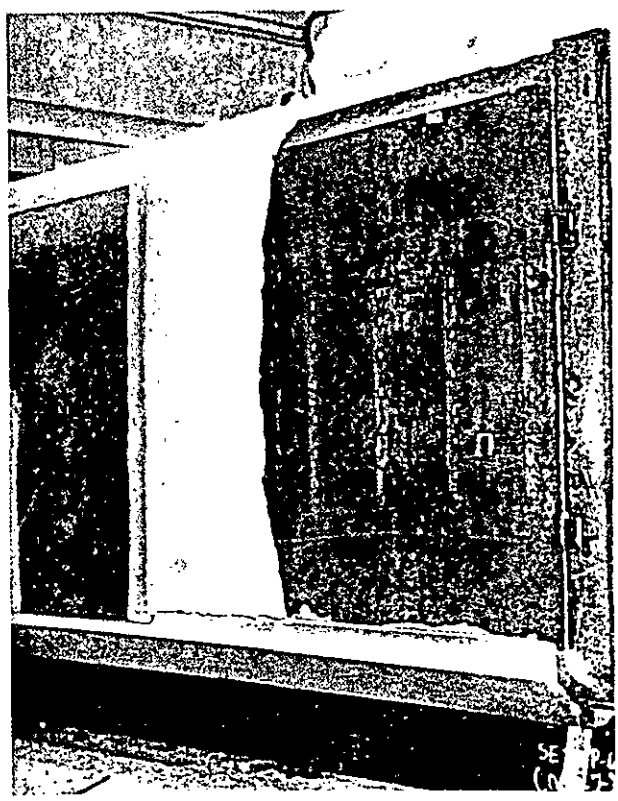
A 4-in. layer of low-thermal conductivity glass-blanket insulation, identical to that used on lower capacity units with pressures over 700 psi, is compressed to 2-1/2 in. between the membrane wall and 20-gauge, water-tight, box-ribbed lagging.



Box-ribbed lagging is applied over insulation and membrane walls on higher capacity units.



Assembly of membrane wall.



Outer lagging is applied over insulation and inner-skin casing.

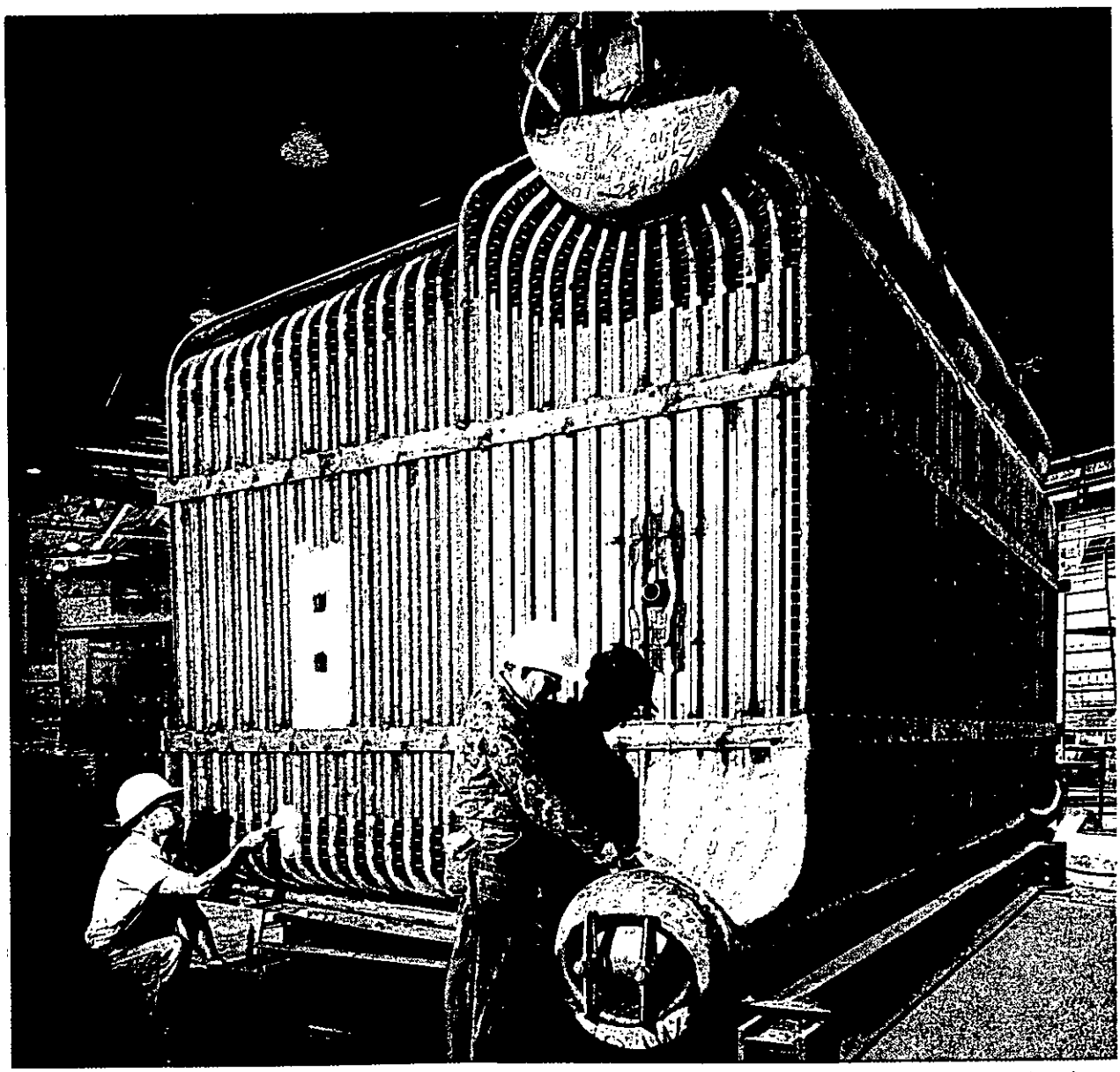
Maximum furnace wall cooling reduces maintenance.

Furnace wall water-cooling cuts refractory associated maintenance to a minimum.

Side and division walls, as well as the roof and floor of many competitive designs, are completely water-cooled. But it's the target wall of the furnace that really takes the punishment. It's the target wall that's the weakest link on other types of skin-casing designs.

A unique tube circuit providing total water cooling of the furnace rear wall has been designed for the FM. Not only has this design enabled B&W to eliminate the brick — and the maintenance — on the target wall, but it also provides the FM boiler with the additional benefit of skin casing in this area just like the side walls, roof and floor.

Another casing weak link often occurs in closure details, corner seals, and areas where tubes enter the drums or are welded to the base frame. Special attention also has been paid to design in these critical areas.



Inner-skin, gas-tight casing for this package boiler setting — including a unique tube circuit providing total water cooling of rear wall — eliminates brickwork and reduces maintenance on high-duty target wall.

A complete line of auxiliary equipment.

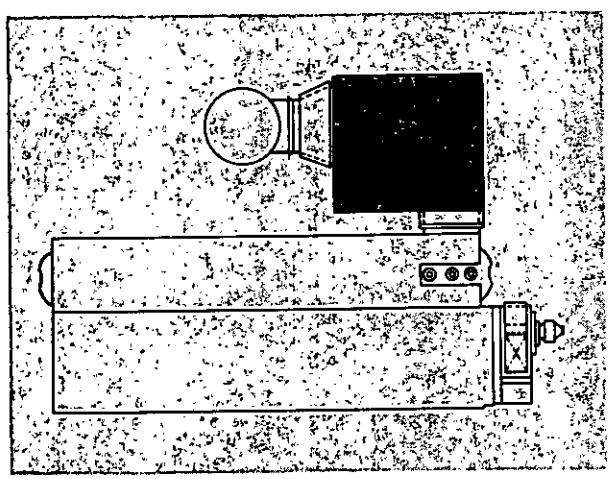
Superheaters, economizers, air heaters and boiler cleaning systems are available for FM boilers in accordance with operating and economic design considerations. Additional accessory equipment, including forced draft fan and drive, junction piece, flues and ducts, stacks and an oil pumping and heating set can be ordered to simplify planning and engineering.

Superheaters.

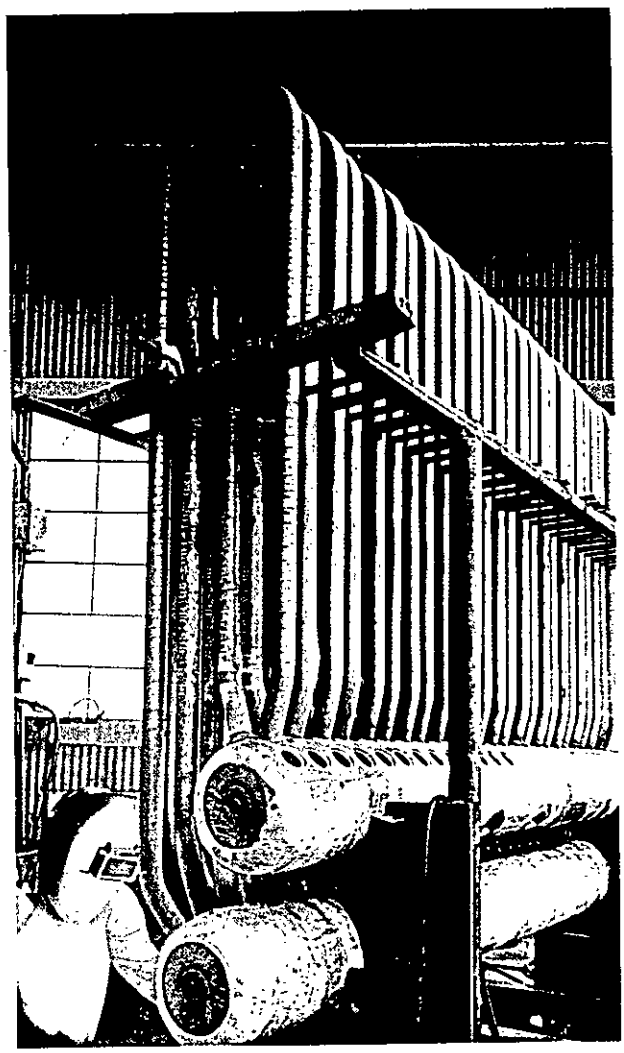
Proven, dependable, full-drainable superheaters — especially designed for the FM — are available. Vertical-tube design provides positive bottom support and excellent expansion characteristics. Multi-pass steam flow insures high steam velocities and good distribution of fluid throughout, to provide cooling for each tube. The superheater unit can be ordered initially or added to the FM at any time. Because it is positioned out of the full radiant heat zone, it has a convective-radiant temperature characteristic for a relatively constant superheater steam temperature over the load range. Steam outlet is conveniently located at floor level.

Heat traps.

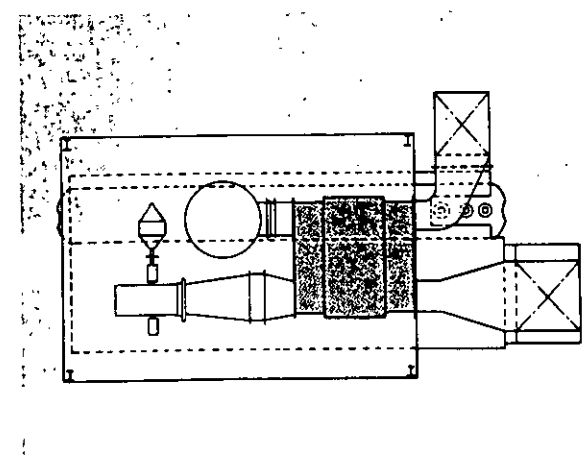
Heat traps are available for increased efficiency. Pre-engineered arrangements of extended-surface or bare-tube economizers and regenerative or tubular air heaters are offered to meet varying space, fuel and economic considerations.



Typical economizer arrangement.



Assembly of superheater.



Overhead air heater arrangement.

B&W burners designed for B&W boilers.

The integral furnace FM is equipped with the most modern firing equipment available for the best overall economy and performance. Both CR and STS burners are supplied for various fuel oils and high- or low-pressure gas. The integrated burner system consists of burner and ignitor, forced draft fan and drive and combustion control equipment with burner safety and programmed lighting sequential controls. The system permits fast response, safety and flexibility of operation.

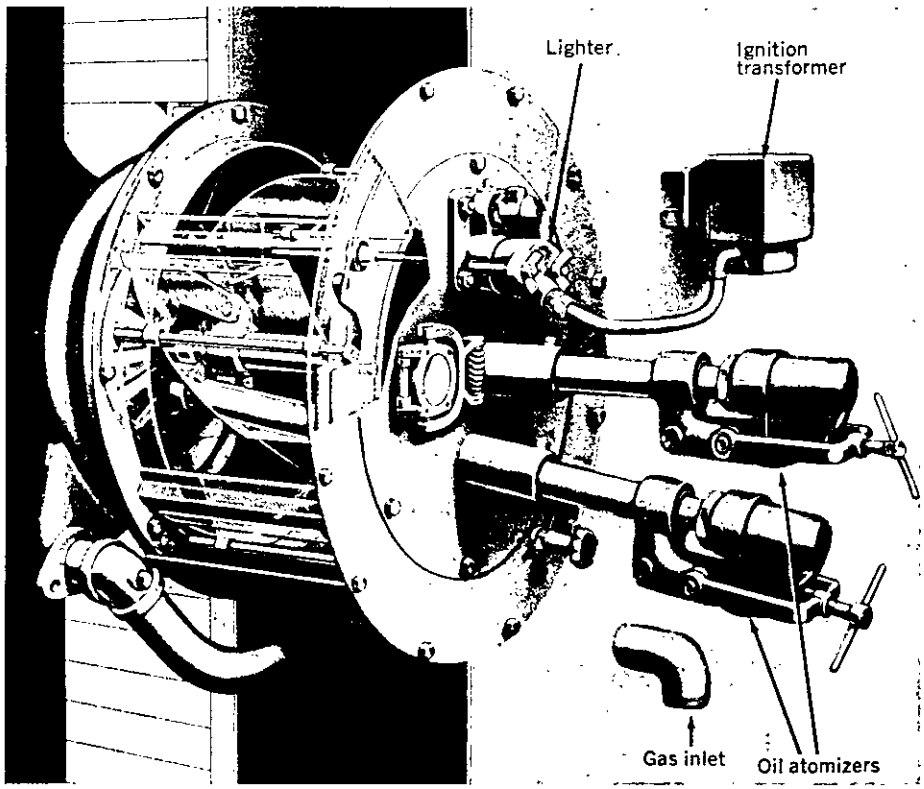
Units are designed for both oil and gas firing to take advantage of lowest fuel costs. Conversion from one fuel to another is accomplished quickly and conveniently. Modified designs are available for various by-product gases and oils.

Optional dual-oil atomizers permit cleaning the main gun without reducing steam production.

CR burner.

The B&W Circular Register burner, "Y" jet oil atomizer, and multi-spud gas elements are available for lower capacities, and incorporate these significant design features:

1. No moving parts.
2. Rugged components, uncluttered appearance.
3. Oil atomization with steam or compressed air.
4. Positive light-off with B&W gas lighter. No pilot is required.
5. No additional gadgetry such as auxiliary motors or compressors are needed.



"Y" jet oil atomizer supplied with CR burner

Circular register (CR) burner for liquid and gaseous fuels is available for lower capacities.

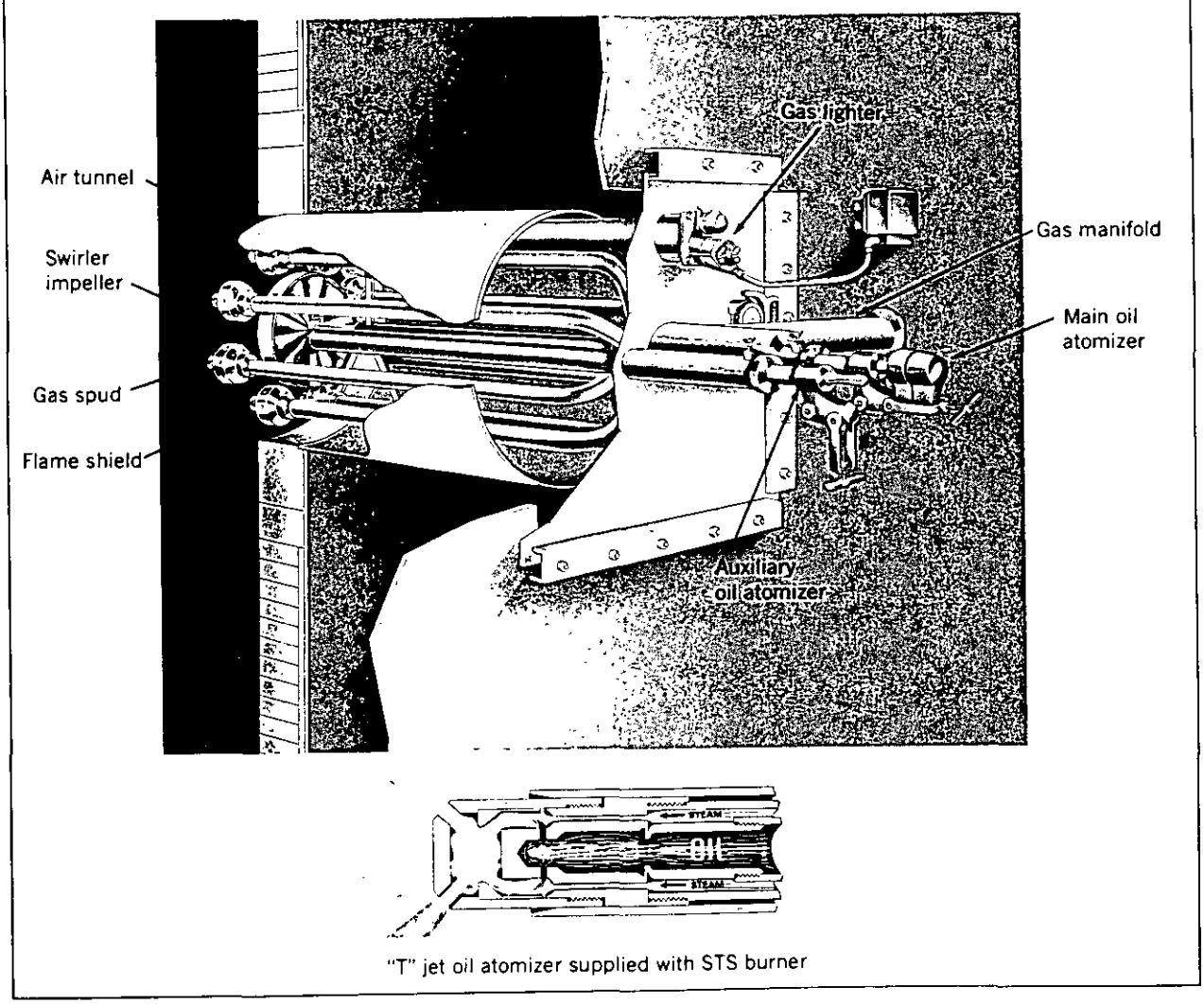
On larger CR burners, the gas burner manifold is positioned back in the windbox and well out of the fire zone. Spud elements extend from the manifold into the burner throat. The spuds are drilled with large holes to prevent pluggage. An extremely stable fire is achieved over a wide load range because of flame retention provisions at the end of each spud.

STS burner.

The STS burner is a single-air zone burner specifically designed for combusting liquid and gaseous fuels in the higher capacity FM boilers. It is capable of 10-to-1 turndown ratios on both types of fuels when sufficient fuel pressures are available.

The STS burner incorporates a straight burner throat to produce a narrow flame, and a swirler impeller to produce rapid fuel-air mixing at the burner. Flame shields are provided on each gas spud for flame retention. These features are essential for completing combustion within the confines of the integral furnace in higher capacity package boilers.

The CR and STS burners have been specifically designed for the FM boiler. Other burner designs may be applied to the FM boiler, but a B&W engineering review of their performance characteristics and suitability to the furnace geometry must be secured.



"T" jet oil atomizer supplied with STS burner

STS burner, also suitable for both fuels, is supplied for higher capacities.

Compatible automatic controls simplify operation.

No one experienced in the design and operation of boilers underestimates the contribution the control system makes to reliable, efficient operation of the complete package.

B&W makes all the major components of the FM package — including boiler, burner and controls. The new innovative ECONOPAK™ control package has been designed and manufactured by Babcock & Wilcox. The entire, quality system is compatible, pre-engineered and simple to install.

Combustion control.

B&W's ECONOPAK™ pneumatic control system permits automatic operation with minimum supervision. The standard installation consists of a small free-standing control front-mounted panel and boiler front-mounted valve trains with start up programming and safety interlock system.

The panel houses the pneumatic controllers and master selector station. It also has room for optional meters, recorders and other selector stations. Many options are readily available for shop-mounting on the panel, including a steam flow, air flow and flue gas temperature recorder.

The ECONOPAK™ is easily field connected to the shop-mounted front burner fuel trains by a single sturdy plastic tubing umbilical cord which can be made to variable lengths to suit plant layout. The entire control package has been B&W engineered for ease of operation and maximum maintenance accessibility.

Completely boiler front-mounted valve trains include spark-ignited natural gas or propane lighter, atomizing steam, main fuel oil (#2-6) and/or main gas systems. The gas train is shipped factory assembled and tested for simple field mounting.

Safety control.

The standard B&W ECONOPAK™ automatic start up/shutdown programming and safety interlock system conforms to the requirements of most insurance and regulatory agencies. The system is complete with a "first out" annunciator which tells the operator of malfunction, should it occur.

Service.

A single B&W service engineer, the same B&W service engineer who's been helping start up the other components in your FM package, is available for the controls and to make certain that each component of the package operates as designed — as part of a totally integrated system.

Interference with plant production is minimized. Connections are easily made for fuel, main steam, compressed air and electricity, as well as for breeching, vents and drains, necessary to complete the steam generating package.

Optional controls.

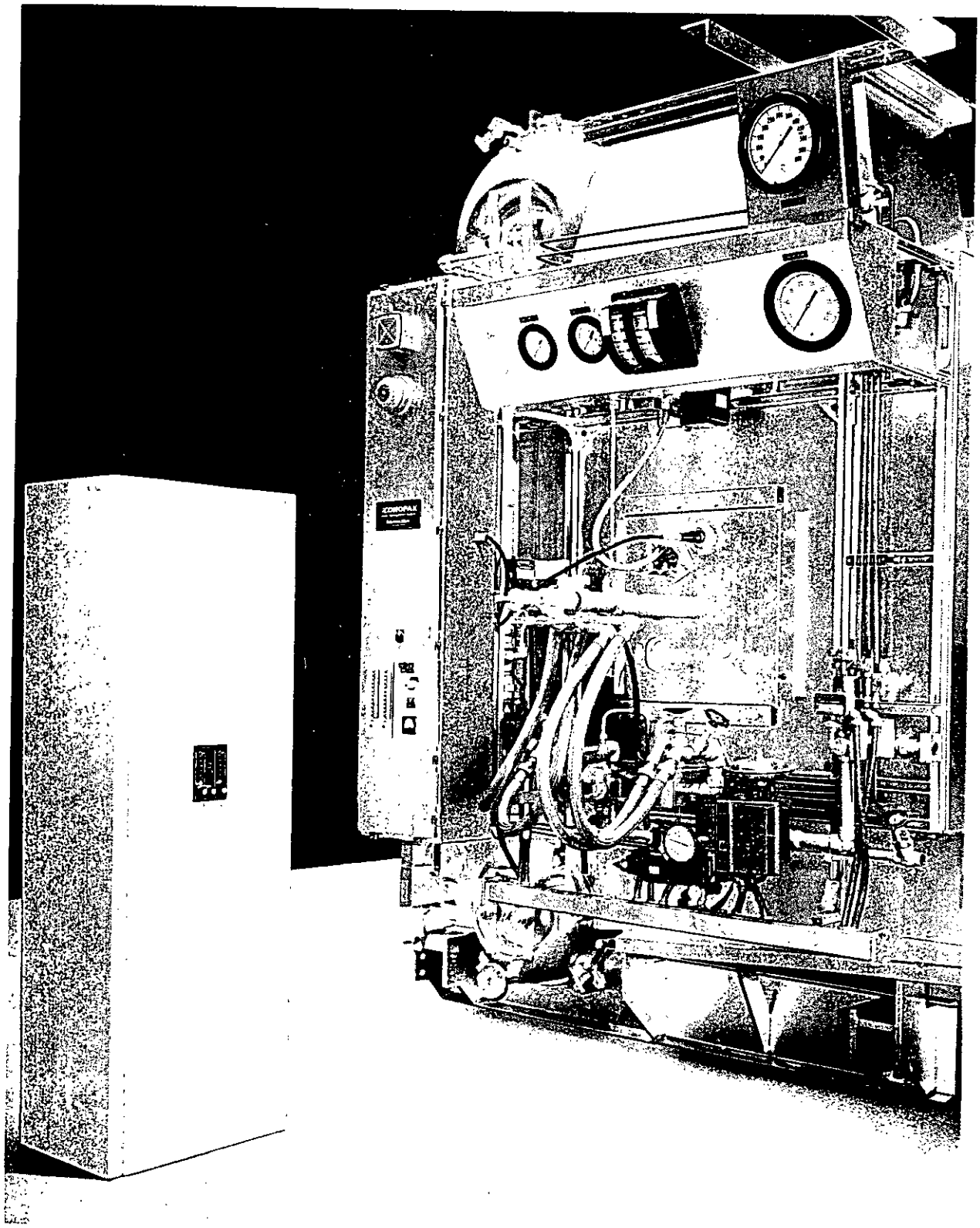
Coen FYR-COMPAKS™ are also available for either electric or pneumatic operation. During the past 20 years, many FMs have been equipped with these boiler front-mounted packages.

FM controls come in varying degrees of sophistication — from electric positioning to parallel pneumatic to fuel-air ratio — complete with cross limiting and flow tie-back. Components of these systems can be furnished by most of the major control hardware suppliers.

Instrument options

A separate free-standing panel can house a variety of additional instrumentation, as well as the popular "O_2 Trim" components. These components provide vernier adjustment to fuel-air ratio control for minimizing excess air and maximizing efficiency.

B&W's ECONOPAK™ combustion and safety control system designed specifically for the FM package. The pneumatic combustion control system maintains correct proportions of fuel and air at all loads. Rapid load swings, therefore, are handled easily while maintaining efficient combustion, proper water levels and maximum safety.



For more information contact your nearest B&W sales office or write: Sales Services, Babcock & Wilcox, Industrial and Marine Division, North Canton, Ohio 44720.

Atlanta, Georgia
Boston, Massachusetts
Charlotte, North Carolina
Chicago, Illinois
Cincinnati, Ohio
Cleveland, Ohio
Denver (Lakewood), Colorado
Houston, Texas
Kansas City (Overland Park), Kansas
New York, New York
North Canton, Ohio
Philadelphia, Pennsylvania
Pittsburgh, Pennsylvania
San Francisco, California
Seattle, Washington

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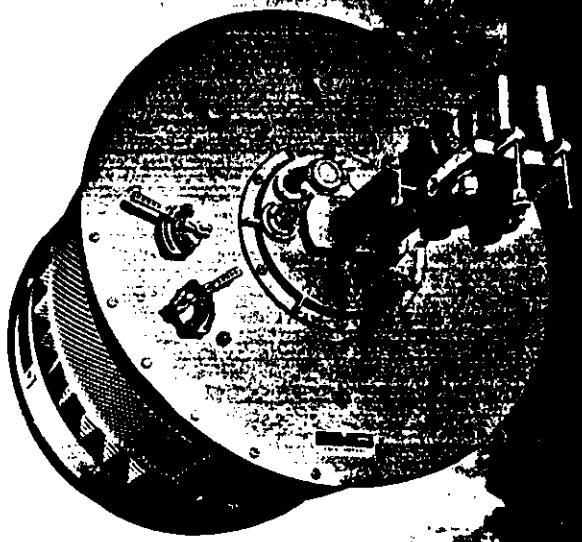
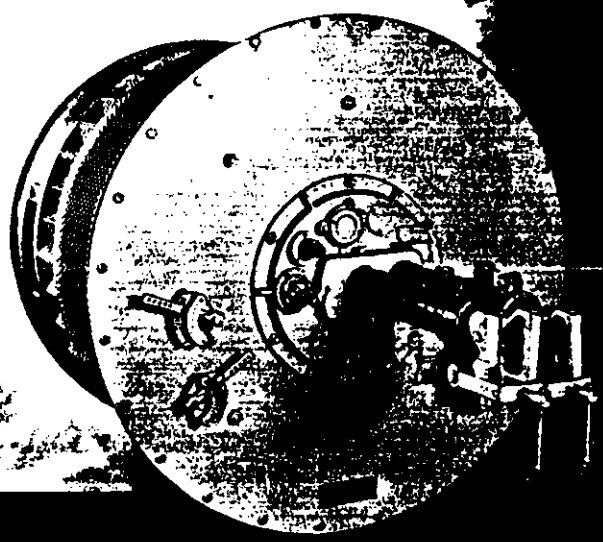
COEN REGISTER BURNERS





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Proven Coen Designs Provide Reliable Burner Performance

Coen Register Burners

From industrial furnaces, power boilers, large utility boilers and marine ship board power plants, to auxiliary boilers, the Coen register type burner is designed and built with rugged construction to provide maximum versatility and years of trouble free service.

Coen register burners provide a means for introducing and thoroughly mixing oil or gaseous fuels and their combustion air into a furnace for maximum combustion efficiency. While Coen registers are available in a wide variety of sizes and types, they all utilize the principle of admitting and controlling the swirl of combustion air through adjustable louvers. All are capable of stable, wide turndown over the entire firing range.

To cover the wide range of applications required by industry *today, the register burner is available in several types:*

SAZ Register (Single Air Zone):

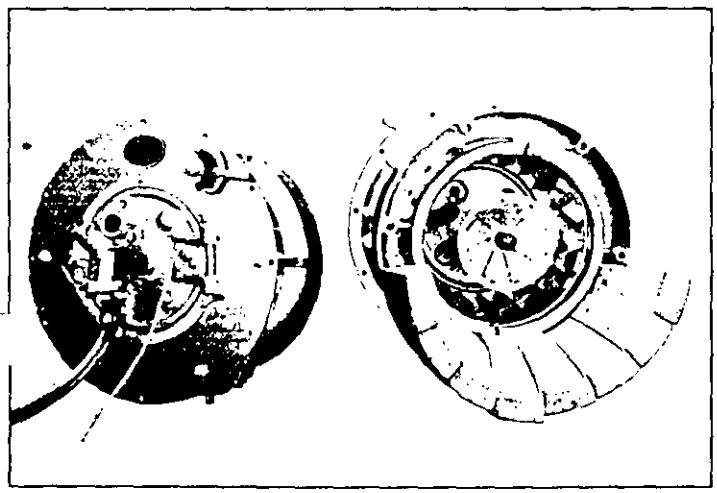
- Single set of register louvers provide the necessary swirl of air for combustion.
- Used on a multitude of combustion applications where adequate furnace widths/diameters are available.
- Used for up to 30 – 45 million BTU/HR heat input per burner, depending on application.

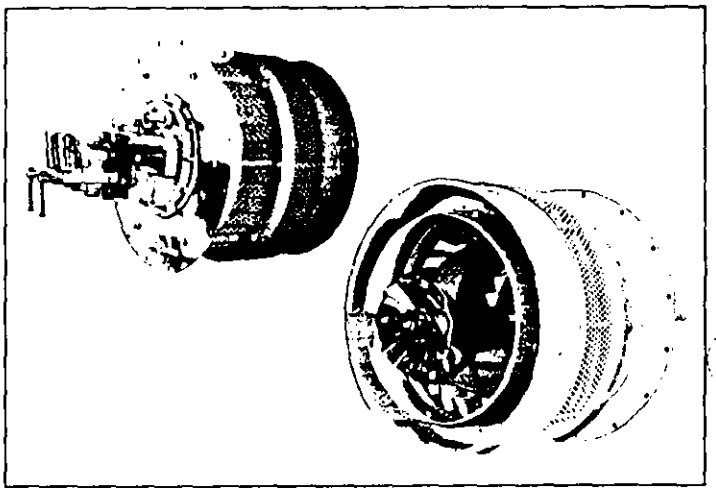
DAZ Register (Dual Air Zone):

- Utilizes two sets of louvers which divide the combustion air into two counter rotating concentric air streams.
- Provides violent mixing as the two air streams cancel rotational velocity resulting in a short, narrow flame body.
- Used on a variety of industrial furnace applications where the unique *DAZ* flame forming characteristics are better suited than its generally smaller sister *SAZ* design.
- *Suited for single burner applications on moderate to high* capacity packaged water tube boiler with narrow furnace widths or multiple burner close side wall applications.
- Adaptable to a wide range of industrial/utility multiple burner applications due to its ability to shape the flame body to suit conditions.
- Used from as low as 20 million BTU/HR to as much as 300 million BTU/HR heat input per burner.

TAZ Register (Triple Air Zone):

- Utilizes three sets of counter rotating register louvers.
- Used generally on high capacity single burner applications.
- Used for up to 350 million BTU/HR input with the same versatility and flame shaping characteristics as the rugged *DAZ* Register design.





satile Register Burner

Application Flexibility

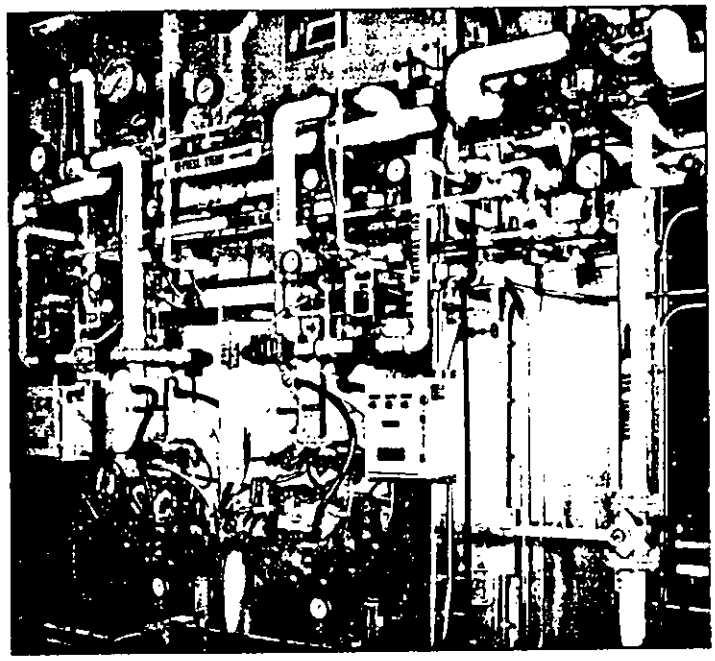
Multiple Burner Applications

For large multiple burner fired boilers, the flexibility of the Coen register burner lends itself well. Because of the ability to adjust register louver settings to suit furnace conditions, coupled with a wide variety of furnace refractory throat exit shapes, flames can be tailored to suit most any boiler furnace shape.

Burners can be equipped for remote control operation with a multitude of options including:

- ON/OFF register louver pneumatic/electric actuators.
- Automatic-retract assemblies for atomizers.
- Gun in place proving switches.

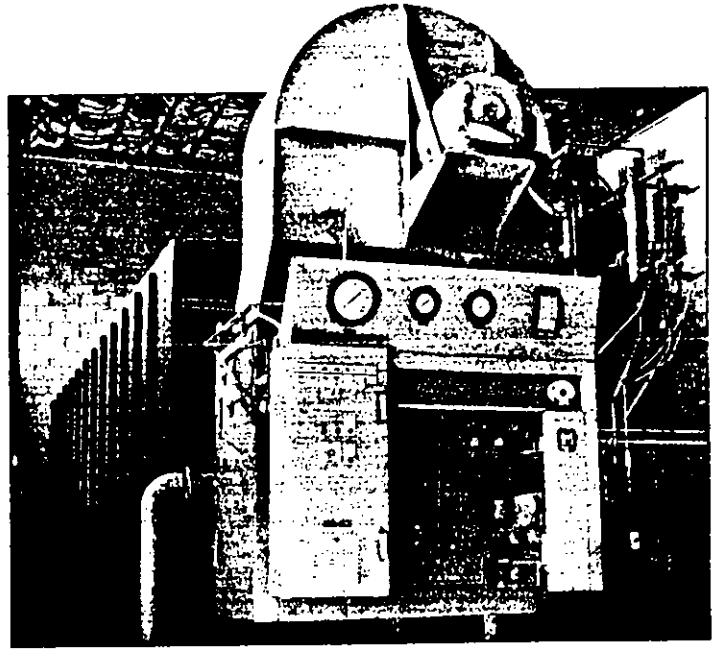
On preheated air applications, the Coen *"CRD"* version of the Dual Air Zone register burner is often used to assure a rugged, versatile burner arrangement compatible with high preheat temperatures.



Single Burner Applications

Because of its ability to tailor the flame shape and flame length to furnace conditions, the Coen register burner is ideally suited to the high space heat release and narrow furnace widths associated with packaged boilers. Coen is the industry leader in packaged single burners for the packaged water tube boiler market.

It is not uncommon to see a Coen single burner up to 225 — 250 million BTU/HR in a boiler furnace width of only slightly more than 6½ to 7 feet. By incorporating the many features associated with the Coen register type burner into the proven *FYR COMPAK™* package, the customer will have all of the advantages of a complete packaged design incorporating burner, windbox, fan, fuel piping, burner management and controls. (See separate Coen *FYR-COMPAK™* bulletin for details.)



...Provides Optimur

Design Features of Coen's Register Burner

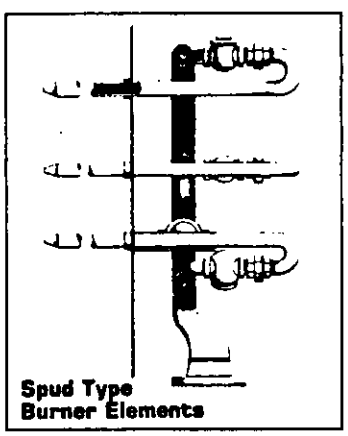
Wide Turndown with Reasonable Excess Air Levels

The Coen register burner, when incorporating Coen's patented automatic register louver control principle, is capable of providing up to a 10 to 1 firing range with reasonable air excess levels over the range. At higher firing rates, excess air levels of 10% on gas and 12½% on oil firing can be attained. On multiple burner installations, even lower excess air levels than these can often times be guaranteed depending on the particular boiler/furnace operating conditions.

Adjustable Flame Shaping

The Coen *DAZ* and *TAZ* registers lend themselves well to flame shaping. Both are capable of utilizing a wide variety of refractory throat tile shapes: from narrow to wide flare exit angles to obtain long narrow flames to short, wide (blossoming) flames depending on the application at hand. Elliptically shaped tile exits are also used in many instances to take advantage of the tall narrow furnaces found on higher capacity packaged water tube boilers.

Gas Burner Elements

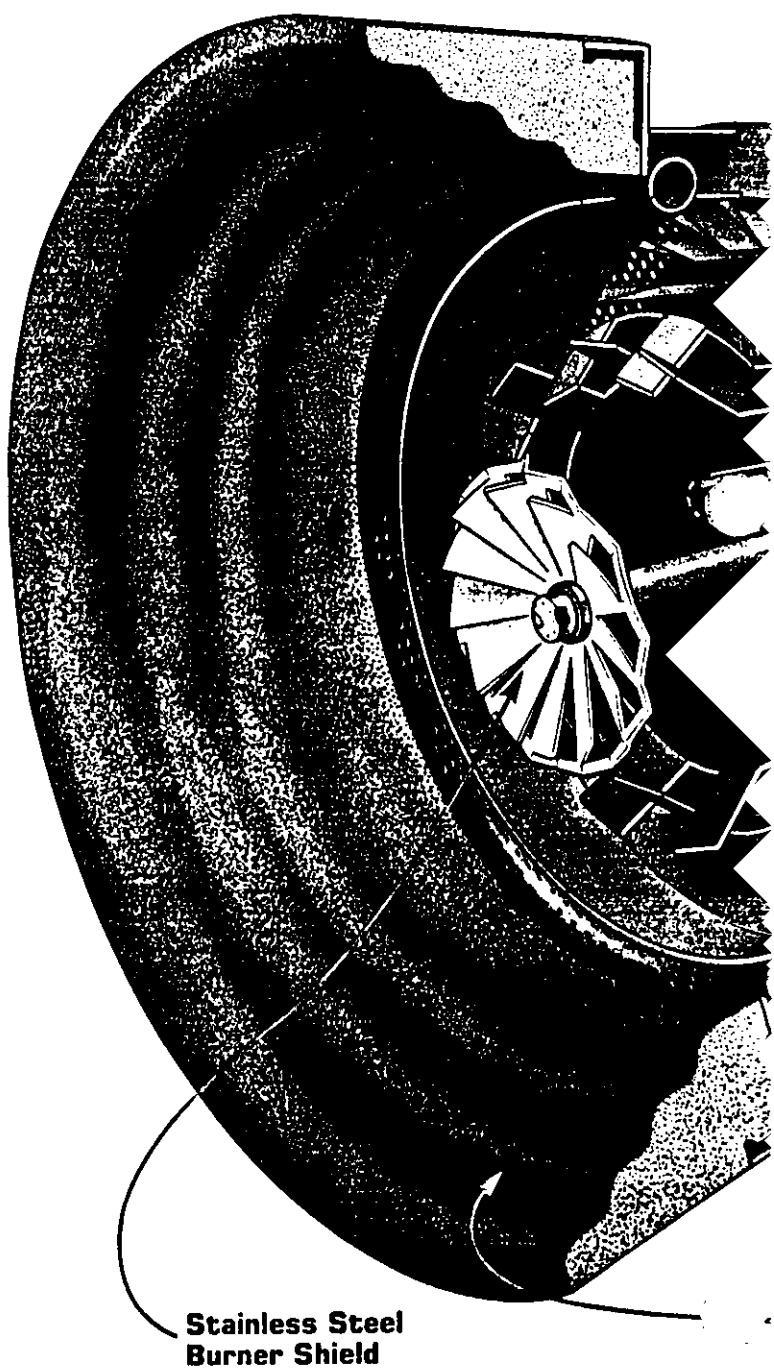


Spud Type Burner Elements

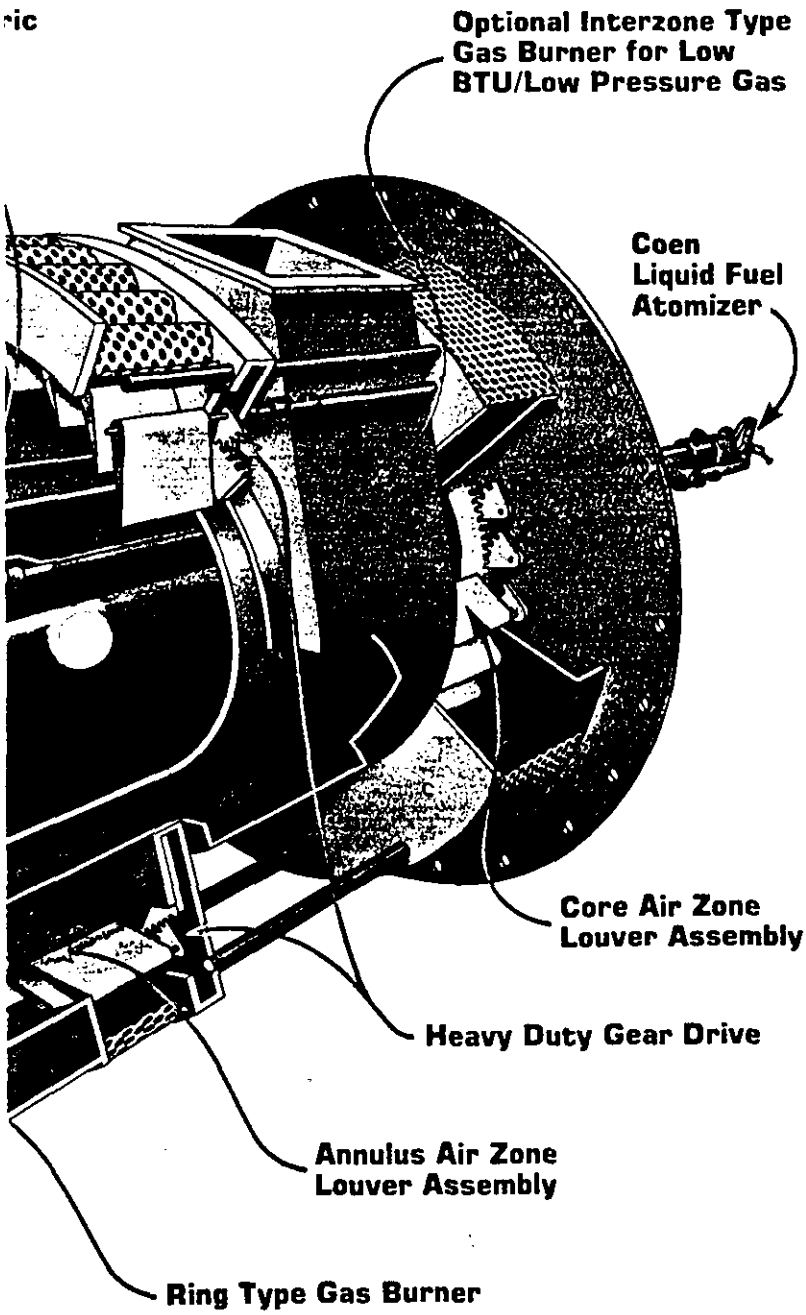
Coen register burners can utilize several types of gas burner elements. The most common, particularly on single burner installations, is a ring type gas burner. This ring type gas burner provides exceptional firing range and flame stability and is especially suitable for moderate to low gas pressure.

Cane type multiple gas spud burners can also be utilized for dirty or unusual gases, such as refinery gas or waste hydrogen gas. Each spud can be equipped with an individual shutoff cock to facilitate on-line cleaning or replacement.

For special applications requiring a third or fourth fuel, a center fire type gas burner can be used, sometimes in conjunction with a ring type burner and/or spud type burner.



Combustion



Coen Preformed Refractory Thr Tiles are Shaped to Fit the Spe Furnace Geometry

Liquid Fuel Atomizers

Coen offers a wide variety of atomizers utilizing steam, air, or gas atomization adaptable to liquid fuels ranging from light grade liquid fuel oils, to the heaviest of oils that require heating, to coal-water slurries (CWM or CWF). See Coen bulletin on liquid fuel atomizers for details.

For remote operation on multi-burner applications, atomizers can be equipped with automatic-retract assemblies, pneumatically operated.

Auxiliary Atomizer Feature

Often on a single or multiple burner application it is essential to change oil burners on a given register without shutdown. This arrangement utilizes an auxiliary full load atomizer alongside the main oil atomizer to permit changing atomizers while maintaining full burner capacity.

Coen Low BTU Gas Interzone Burner

Shown as an option (left), the interzone scroll type gas burner is a version of the Coen *DAZ* register, with a scroll placed between the two counter rotating sets of register louvers. This permits large volumes of low BTU gas or very low pressure gas to flow through the burner with very little pressure drop. Gas burner pressures of as little as 4 to 12 inches W.C. burner pressure drop can be accommodated with this design. See Coen bulletin on low BTU gas for additional details.

Coen Dual Air Zone Scroll Feed Burner

Similar in design to the above interzone burner, the Coen *DAZ* Scroll Feed Burner is designed to burn pulverized solid fuels in suspension, such as coal, woodwaste, or biomass. See Coen bulletin on biomass combustion systems for details.

Fuel Flexibility

The Coen register burner, firing fuels separately or simultaneously with each other, lends itself well to a multitude of gaseous, liquid, or solid fuels. It is particularly adaptive for waste liquid, waste gas firing, or plant by-product waste.

Igniter Flexibility

Available with a wide range of gas or oil igniter pilots for interruptible or continuous operation. Also available with Coen high energy igniter for direct ignition of fuel oil.

Register Louver Operators

Coen's patented automatic register louver control (patent No. 2,818,109) allows for remote operation on multi-burner automated boiler systems. Individual registers can be fitted with pneumatic or electric actuators to provide automatic opening/closing of register louvers to bring on or cut out burners from a remote location. At the same time, for increased efficiency and turndown capability, these same actuators can be designed to modulate automatically with firing rate.

...with Wide Turndow

Engineered Designs for Optimum Performance

Coen Engineering and System Responsibility

Coen's experience enables the customer to use Coen for complete system engineering, including turnkey installation if desired. This could include a Coen system all the way from the fuel tank to the burner, including:

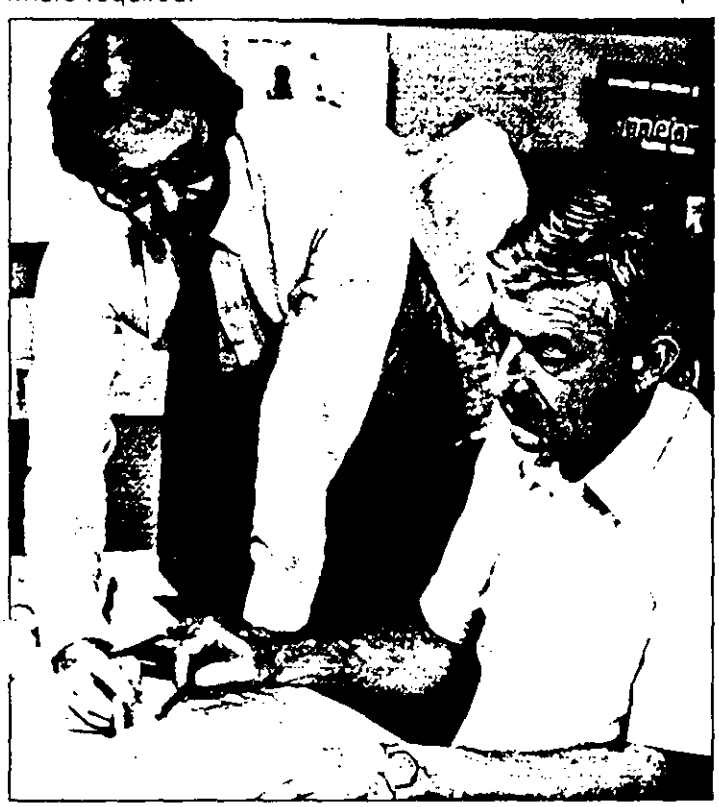
- Tank suction heater
- Transfer pump sets
- Fuel oil pumping and heating sets
- Burner management systems
- Combustion control and instrumentation packages
- Environmental control equipment, where required.

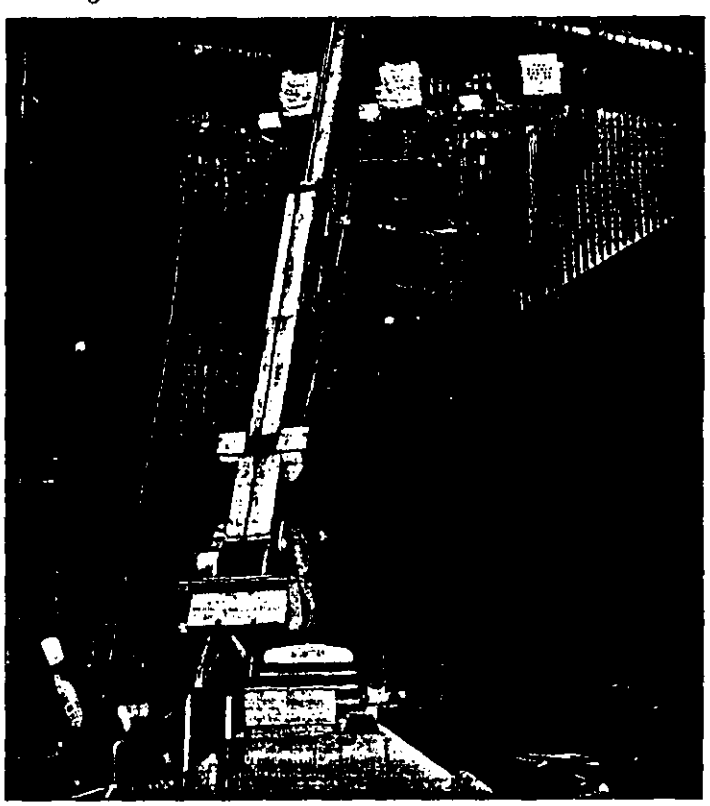
Low NOx Burner Modifications

For very low NOx levels, design modifications are available to further reduce emissions. The Coen register burner can incorporate flue gas recirculation (FGR) to reduce thermal NOx. The FGR design is extremely effective in controlling NOx emissions with a minimum impact on operating excess air levels and burner flame lengths. This involves mixing a portion of combustion products (flue gas) with the combustion air prior to the initial combustion zone.

With the Coen register burner design, a custom flue gas plenum can be designed integral with the Coen burner such that a separate mixing chamber for flue gas and air is not required to uniformly mix together flue gas and combustion air.

Other methods of NOx reduction are also available, such as fuel/air staging, depending upon application and the level of NOx reduction required. For fuel staging applications, a modified register design ("DAF" burner) can be used employing features from the Coen register burner as well as from Coen's proven parallel flow burner design. Knowing that NOx emissions depend on fuel bound nitrogen, excess air, heat release and heat removal rates, Coen will choose the method of NOx reduction and burner design most economical for your particular installation.

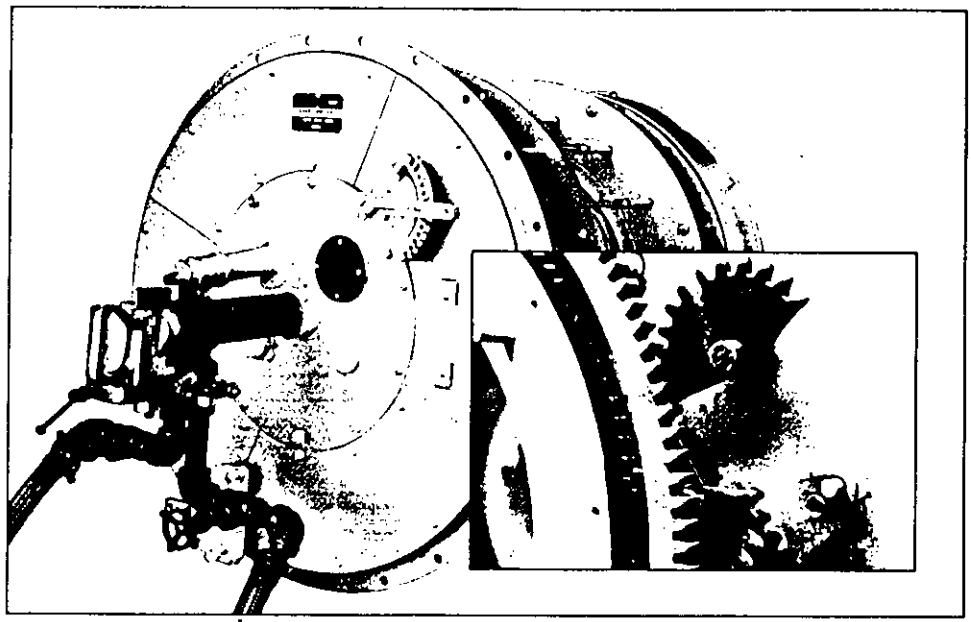


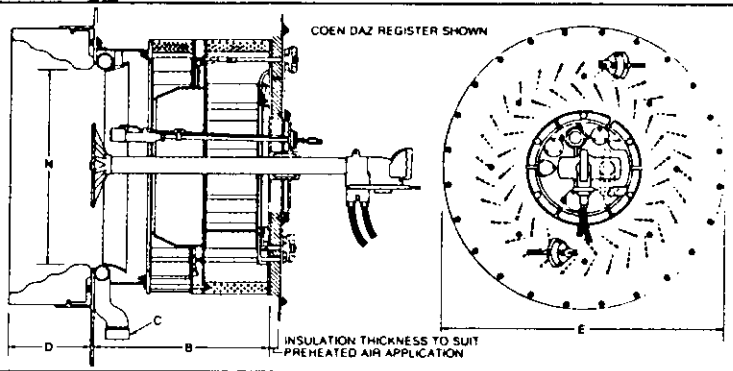


Capability.

Preheated Air Applications

When the register burner is utilized under adverse conditions, such as multi-burner applications with high temperature preheated combustion air and/or in a corrosive atmosphere, heavy duty construction is available and recommended. The Coen type *"CRD"* heavy duty dual air zone register utilizes two heavy duty ring gear assemblies to drive the core and annulus louver blade sections. These ring gear assemblies have removable covers to facilitate maintenance from the burner front without requiring internal access to the burner windbox or burner/boiler shutdown. Individual register louvers are of 303 stainless steel construction. On extremely high air preheat applications and/or turbine exhaust applications for cogeneration projects, higher grades of stainless steel can be used on louvers and other burner internal components.



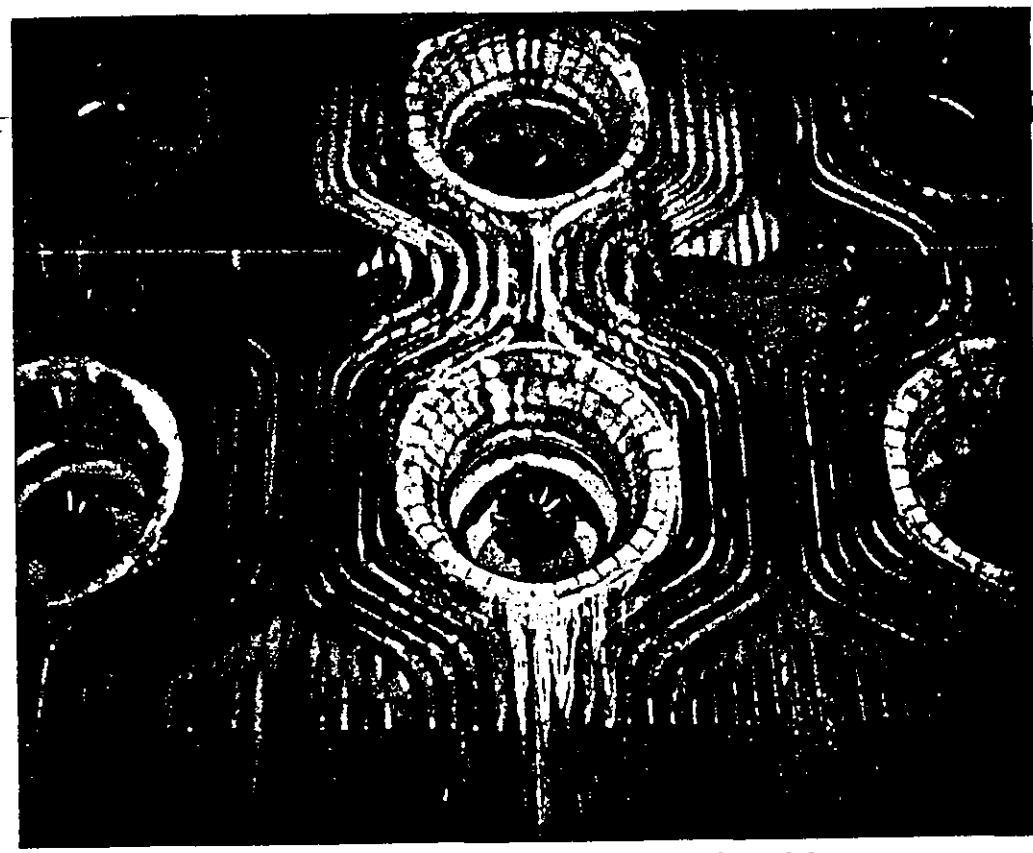


Register Burner Dimensions

	Burner Type	SAZ									DAZ		
N	Nom. Burner Size	14	15	16½	18	20	22	24	25	26	20	22	24
B	Min. Burner Length	13 11/16	13 11/16	16	16	18	18½	18½	18½	18½	22 1/16	22 11/16	22 11/16
C	Gas Inlet Size	2–2½	2–2½	3–4	3–4	3–4	3–4	3–4	3–4	3–4	3–4	3–4	3–4
D	Throat Depth	13½	13½	13½	13½	13½	13½	13½	13½	13½	13½	13½	13½
E	Front Plate Diameter	31¾*	31¾*	36	36	36	36	36	36	36	36	36**	36**

	Burner Type	DAZ									TAZ		
N	Nom. Burner Size	25	26	28	30	32	34	36	39	42	39	42	45
B	Min. Burner Length	22 11/16	22 11/16	30 1/16	30 1/16	30 1/16	30 1/16	30 1/16	37½	37½	41 5/16	41 5/16	41 5/16
C	Gas Inlet Size	3–4	3–4	4	4	4	4	4	4	4	4	4	4
D	Throat Depth	13½	13½	13½	13½	13½	13½	22½	22½	22½	22½	22½	22½
E	Front Plate Diameter	36**	36**	48	48	48	48	48	65	65	65	65	65

NOTES: 1. *36" O.D. Optional, **48" O.D. Optional. All dimensions are in inches. 2. "C" Dimension: Correct size dependent upon capacity required. 3. Size DAZ 30 to TAZ 45 have two gas connections, each 180° apart. 4. Throat depths are typical. Actual depth may vary w/ application.



Coen Register Burners Used Worldwide...

Since 1912 Coen Company has specialized in the design, manufacture and servicing of burners and combustion systems throughout the world.

Coen register burners are found meeting the needs of the power industry with over 10,000 applications worldwide. Coen provides the experience and expertise to insure that each burner system meets exact burner requirements. Burners for special applications include: H_2S burners, refinery heaters, turbine exhaust gas burners, liquid/gaseous incinerators, direct fired air heaters/combustors, blast furnace gas burners, and CO gas burners.

Whether for use in single or multiple burner applications Coen register burners insure versatility, reliability, and years of trouble-free service.

For more information on Coen register burners and other key combustion equipment, contact:

COEN
COMPANY, INC.

COEN COMPANY, INC. • 1510 Rollins Road • Burlingame, CA • 94010 • (415) 697-0440 • Telex: 03-4337

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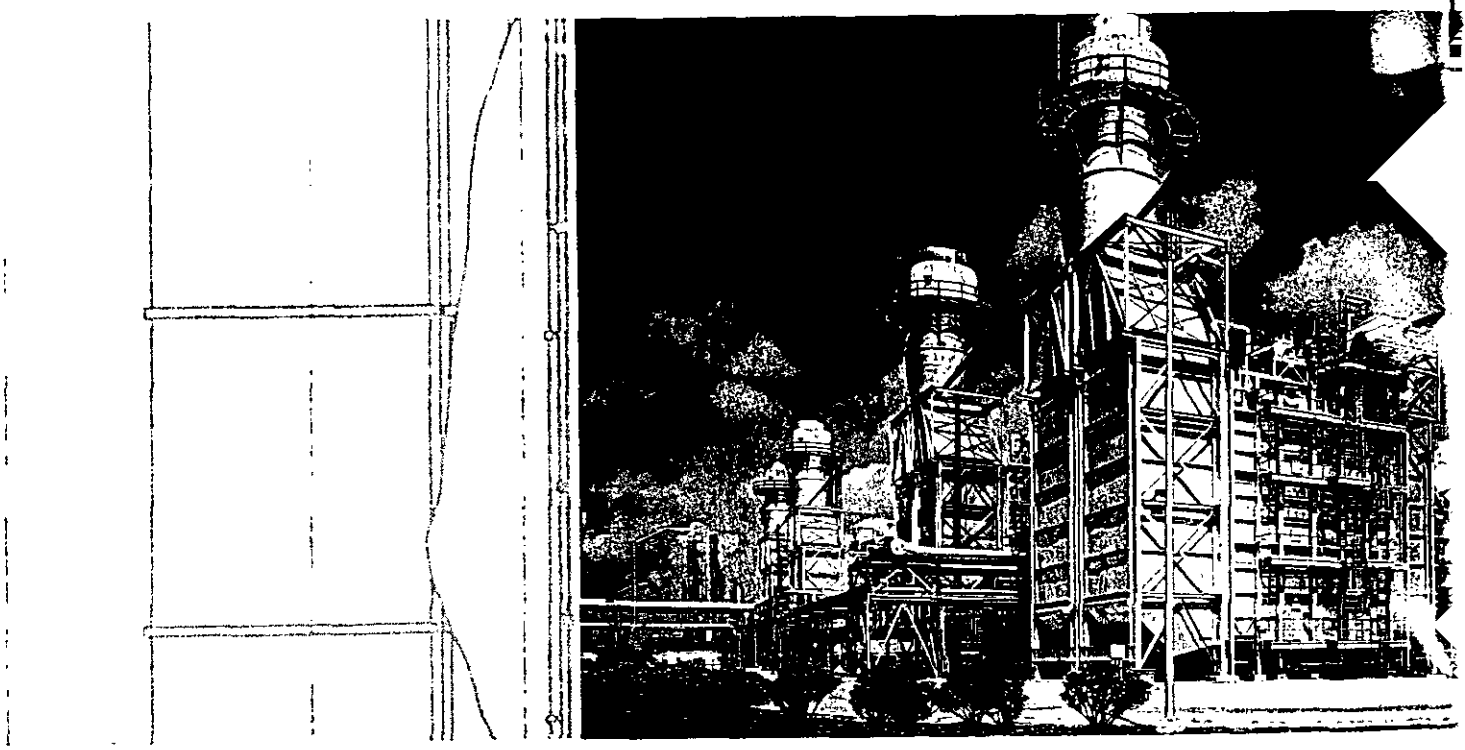
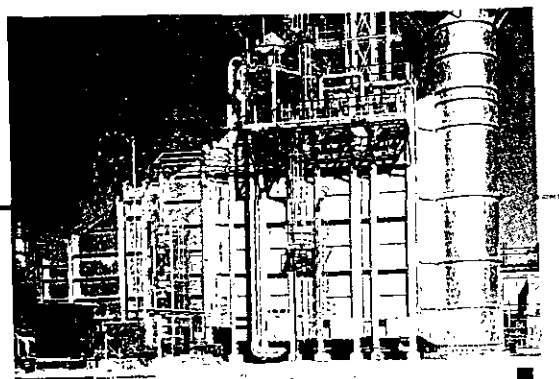
NOOTER/ERIKSEN
COGENERATION SYSTEMS, INC.

NOOTER/ERIKSEN

A SINGLE SOURCE SUPPLIER



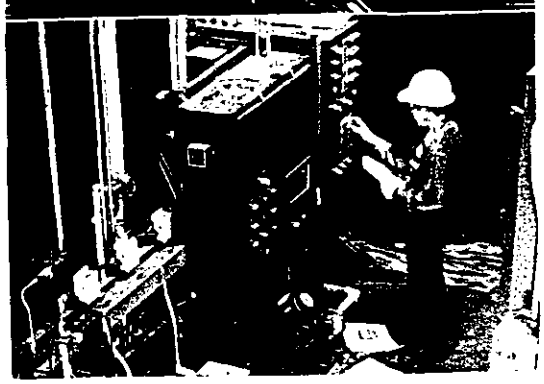


Pages 4 & 5
EXPERIENCE

Pages 6 & 7
DESIGN

Pages 8, 9, 10 & 11
MANUFACTURING

Pages 12 & 13
FIELD CONSTRUCTION



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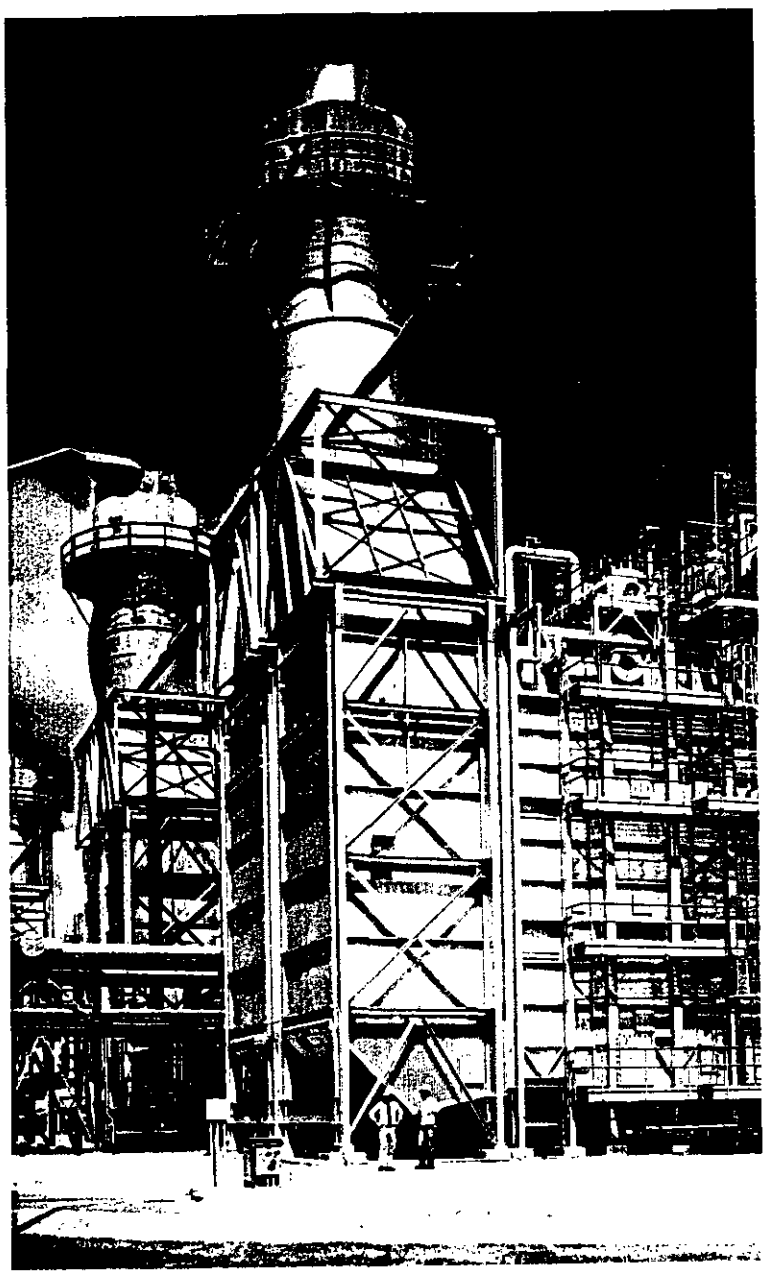
MAINTENANCE

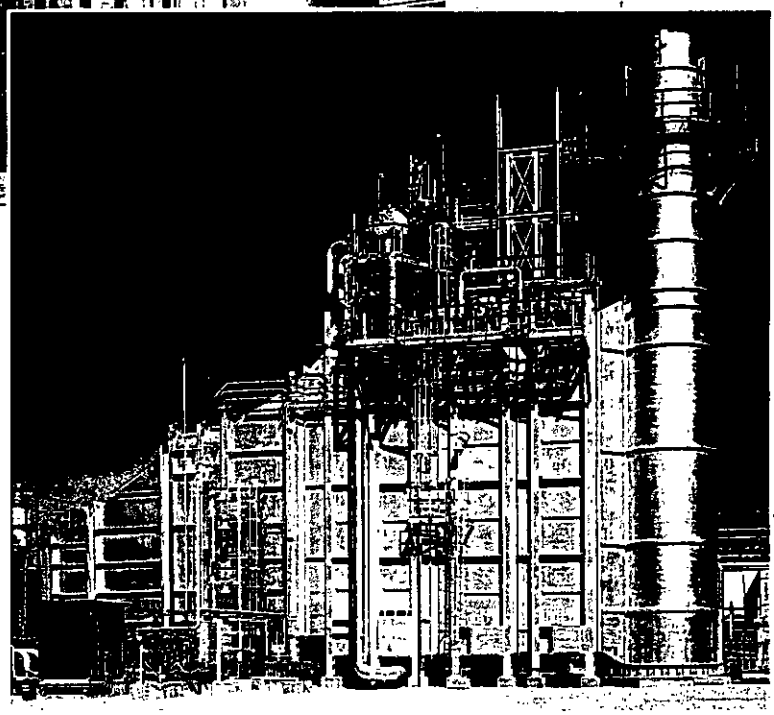
EXPERIENCE

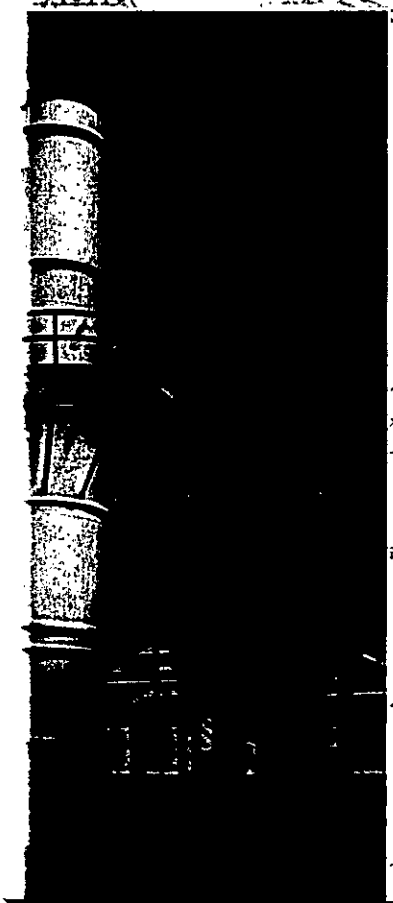


Nooter/Eriksen Cogeneration Systems, Inc. is a single source supplier of heat recovery systems designed to conserve energy and to improve your plant's efficiency.

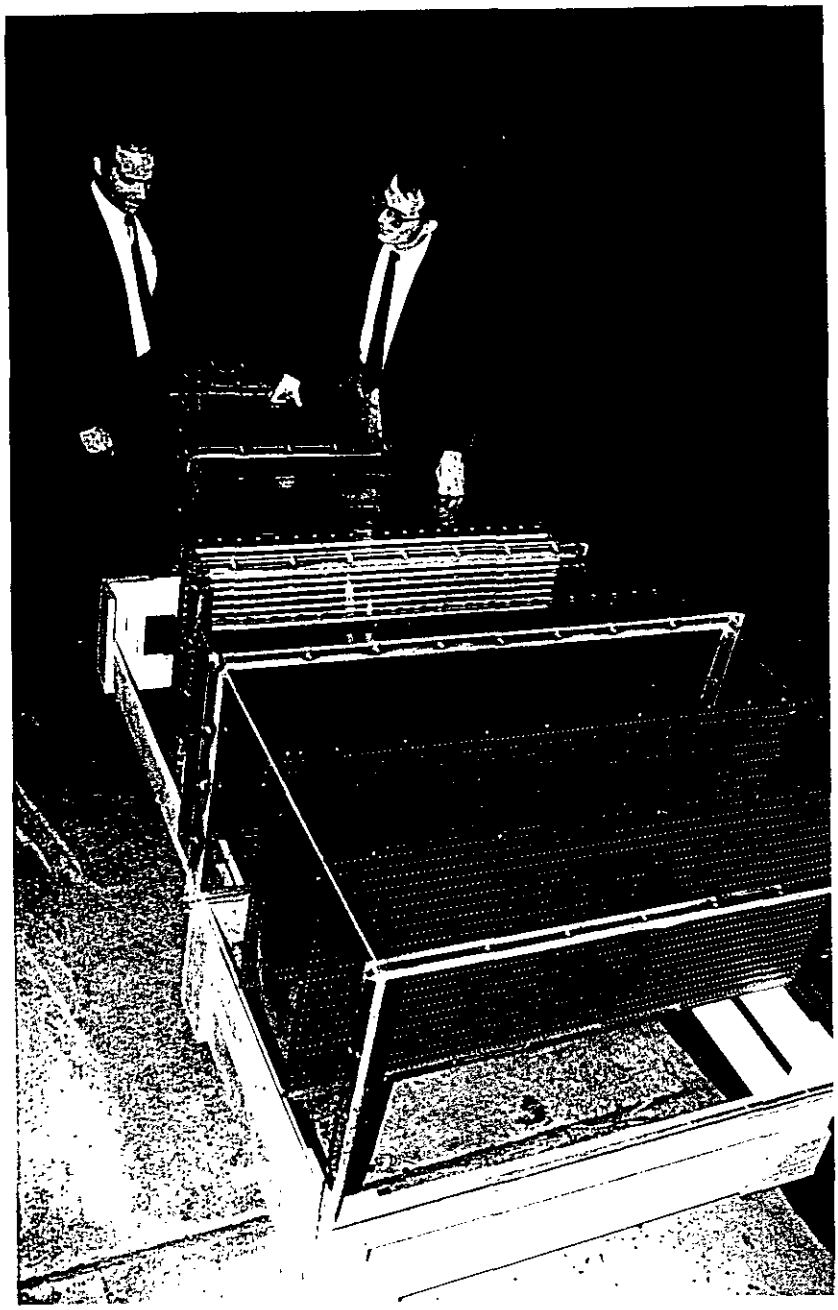
The Nooter/Eriksen team will custom design, manufacture, install and provide maintenance programs for heat recovery systems for a variety of applications.

In addition to numerous gas turbine heat recovery steam generators (HRSG's), Nooter/Eriksen has been responsible for the design and manufacture of wood fired boilers, coke calciner heat recovery systems, municipal solid waste plant heat recovery systems, process coolers, fluid catalytic cracking unit heat recovery boilers, and fire tube boilers.





DESIGN



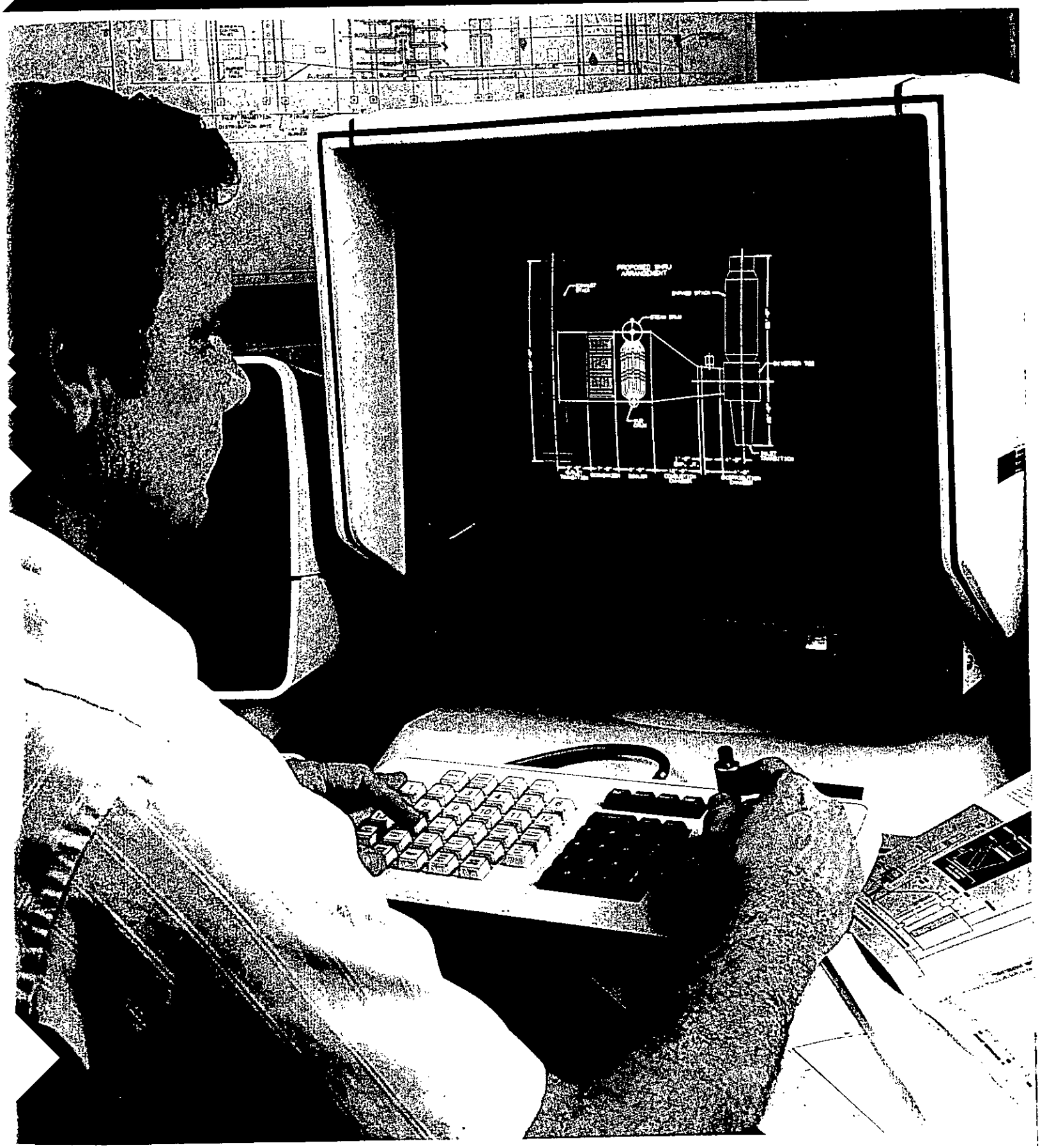
The Nooter/Eriksen team is sensitive to customer needs. Our approach is to initially develop a complete engineering analysis to assure a well planned and effective installation. Complex systems are Nooter/Eriksen's specialty.

Using state-of-the-art computer-assisted design methods, we optimize the heating surface design and simultaneously organize the system into multiple transportable modules. Modular design minimizes field work, thus cutting construction time and expense.

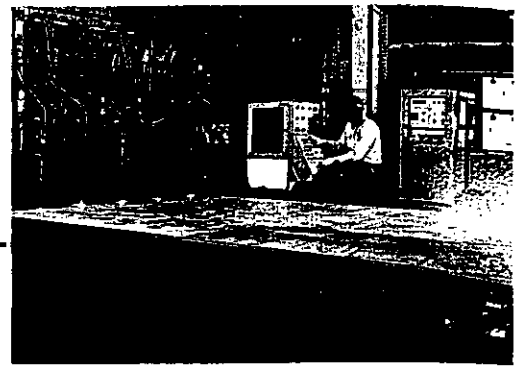
Nooter/Eriksen believes that every heat recovery application should be custom designed to offer the best available compromise between initial cost and overall system efficiency. The Nooter/Eriksen design team approaches each new application on this basis.

All systems are engineered for maximum reliability and availability.

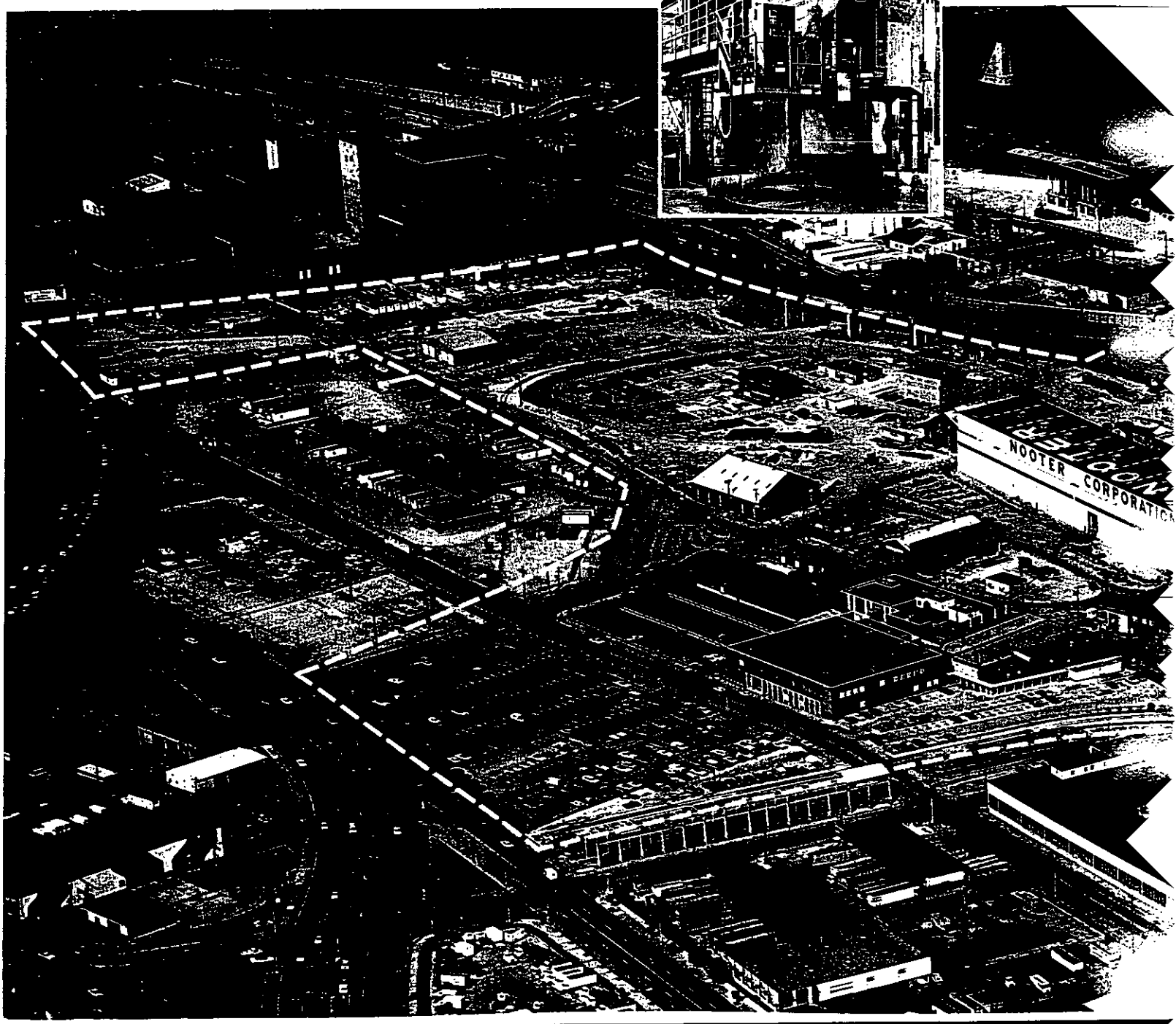
Over 100 successfully operating heat recovery systems reflect the boiler design experience of Nooter/Eriksen system designers.

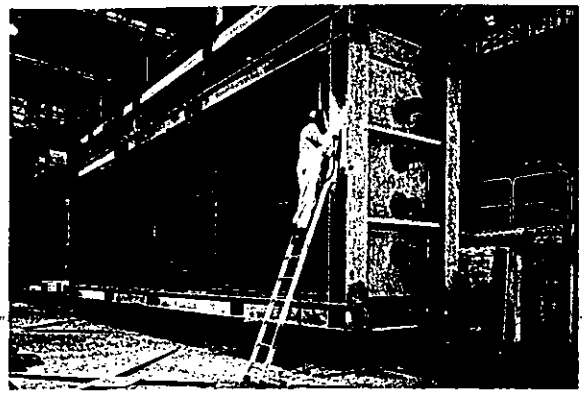


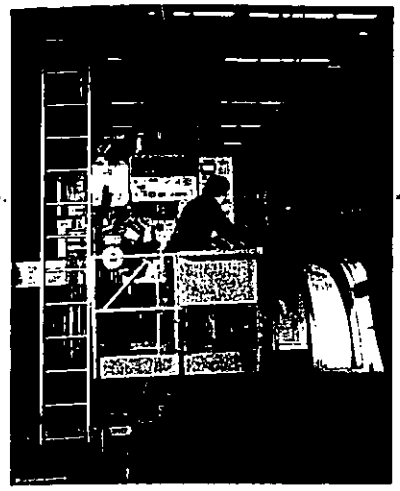
MANUFACTURING

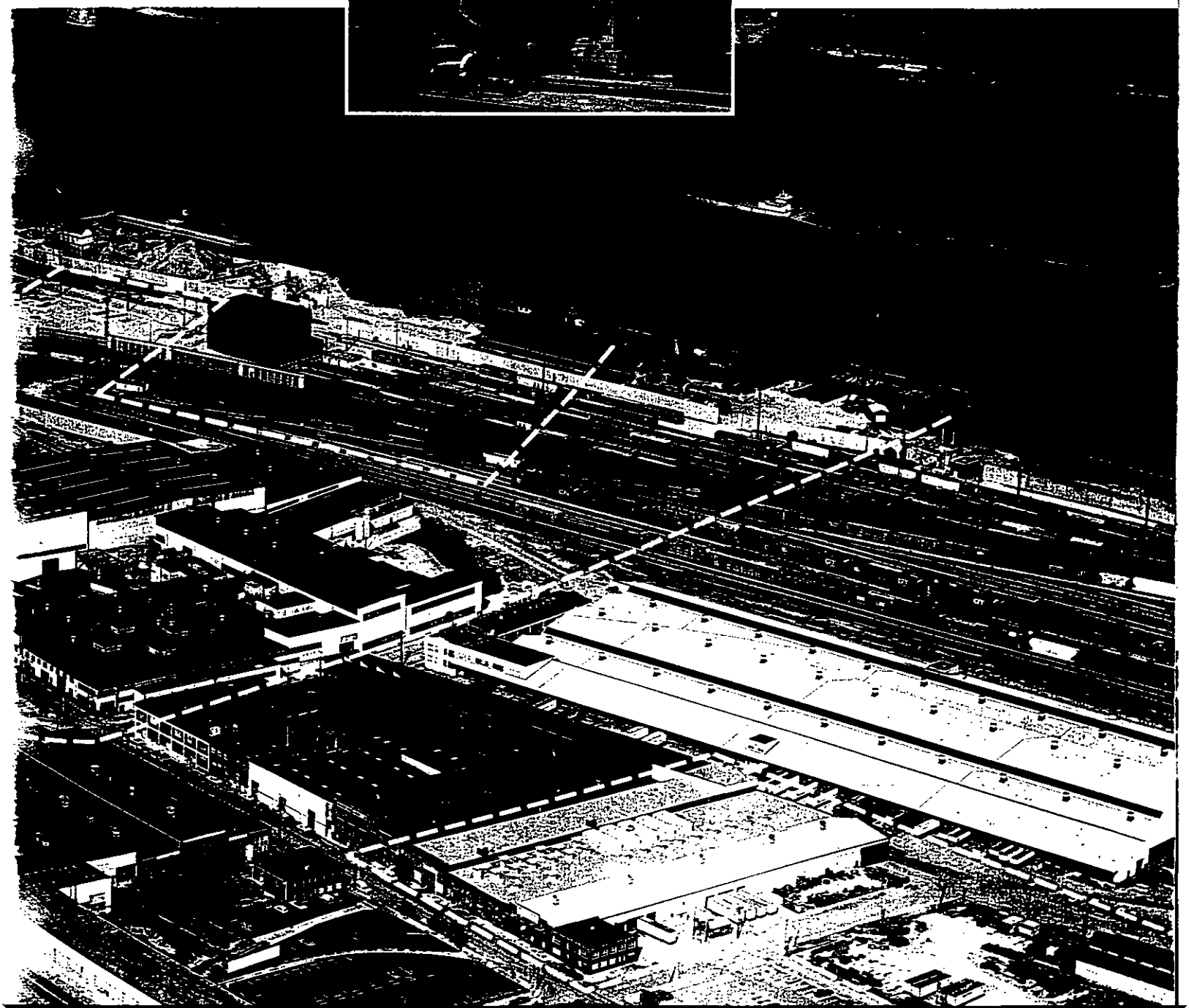


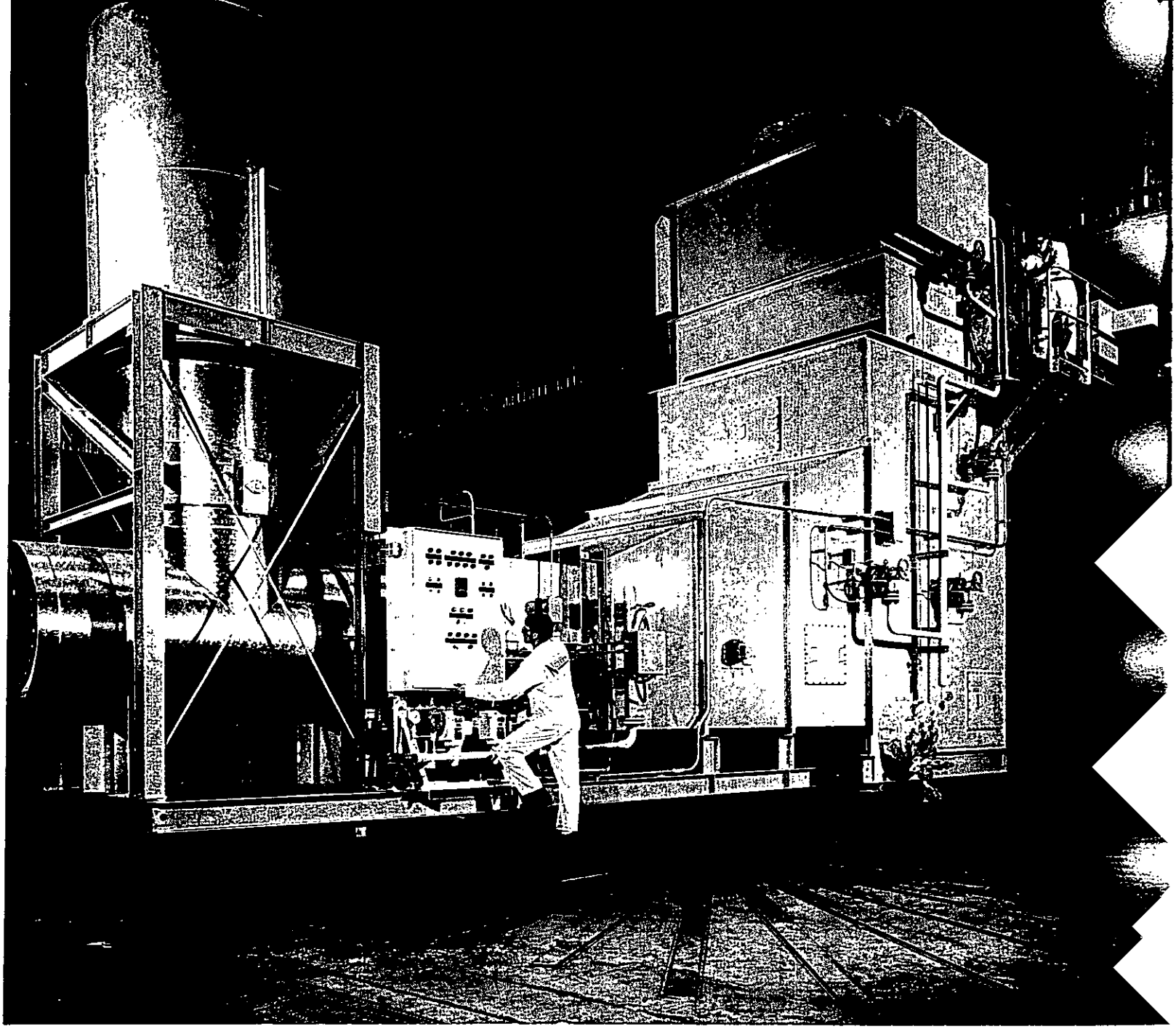
Nooter/Eriksen Cogeneration Systems, Inc. is a wholly owned subsidiary of Nooter Corporation. Since 1896, Nooter Corporation has been a world leader in the fabrication of all weldable metals and the field installation of industrial systems.

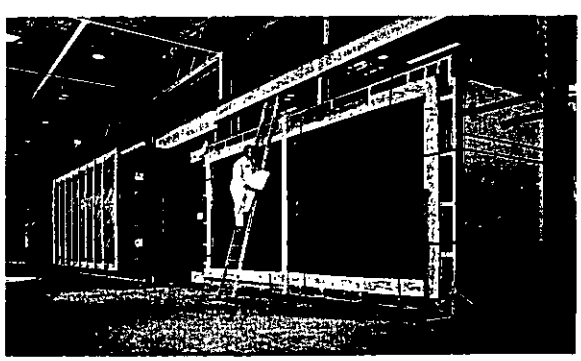












MANUFACTURING

TRANSPORTATION FACILITIES:
All truck and rail lines are available as well as a Nooter-operated barge loading facility on the Mississippi River which enables us to make domestic and export shipments via water.

FINANCIAL RATING: Dun & Bradstreet 4A1

MAXIMUM LIFTING CAPACITY: 500 Tons

ASME CODE REGISTRATIONS:
A, H, S, U, U_2 and a National Board R Stamp certification.

MEMBERSHIP:
National Association Construction Boilermaker Employers
Steel Plate Fabricators Association
Tubular Exchanger Manufacturers Association
Heat Exchanger Institute Incorporated
Heat Transfer Research, Inc.

FORMING: Up to 2000 ton presses
20'-0" maximum length, and 6" maximum thickness

MACHINING: 40'-0" diameter boring mill.
10'-0" diameter x 40'-0" long turning lathes.
3½" maximum drilled hole size.

MATERIALS:

STEELS: Carbon and low alloy steels (to various toughness and strength requirements in accordance with numerous domestic and foreign specifications)

STAINLESS STEELS:
Austenitic, ferritic, martensitic, duplex, and precipitation hardening stainless steels.

NONFERROUS METALS:
Nickel and nickel alloys, copper and copper alloys, aluminum and aluminum alloys.

REACTIVE METALS:
Titanium, zirconium, tantalum, and their alloys.

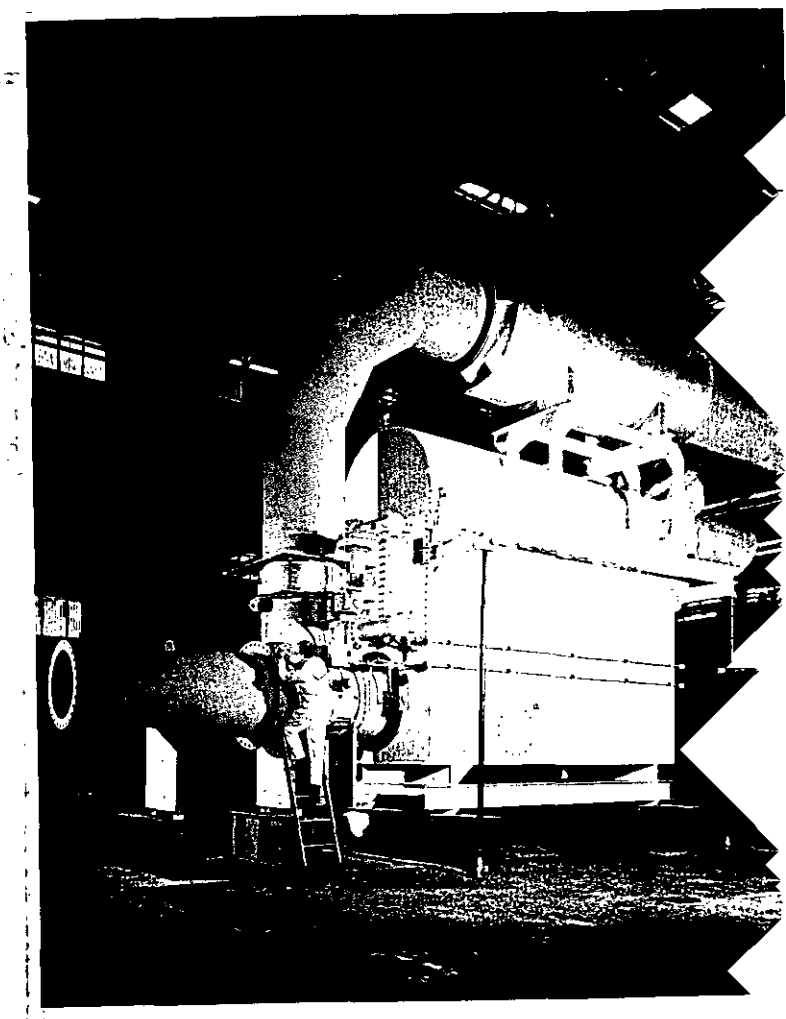
CLADS: Many combinations of stainless steel and nonferrous metal clads on carbon or low alloy steel can be produced and fabricated. The cladding process may be roll-bonding, explosion-bonding, weld-surfacing or a combination of these processes.

WELDING: All processes, manual metallic arc, submerged arc, tungsten inert gas, metal inert gas, plasma, plasma overlay, strip and electroslag.

BLASTING: Sand and glass bead (standard). Others on request.

HEAT TREATMENT:
5 Furnaces to 2300°F maximum temperature.
Post weld heat treat 24'x24'x100' at 1200°F.
Water quench facilities, either spray or immersion.

QUALITY ASSURANCE:
Computerized quality control and inspection.



RADIOGRAPHY:
X-ray and Gamma ray capacity through 6"-thick steel and alloy plate.

METALLURGY:
Complete metallurgical and metallographic facilities. Mechanical test and experimental weld facilities.

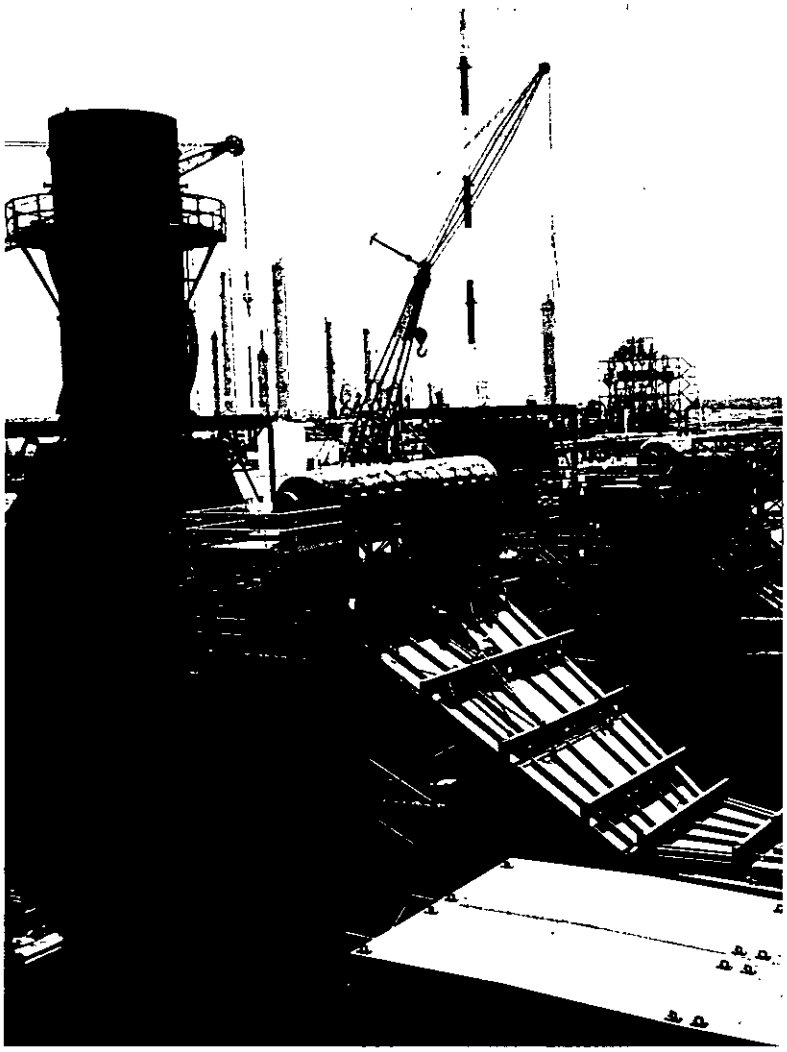
CHEMISTRY: X-ray spectrometer for chemical analysis of welds and materials of construction. LECO dual range carbon analyzer.

INSPECTION: Optical Tooling — Accurate to 0.001". (Computer Controlled)

AIR & HYDROSTATIC: Air — 2,000 psi, Hydro — 50,000 psi.

NONDESTRUCTIVE TESTING:
Ultrasonic flaw detection and thickness measurement, dye penetrant, magnetic particle, vacuum testing, and leak testing utilizing mass spectrometers, halogen detectors, and thermal conductivity detectors.

FIELD CONSTRUCTION



Nooter Construction Company provides a full range of field construction services which complements our manufacturing facility and gives you *"turnkey"* one company responsibility. Nooter Construction Company is an efficient group of construction craftsmen who are ready to serve throughout the northern American hemisphere using the best tools and engineering knowledge available.

Nooter Construction Company offers:

- Experienced rigging supervisors.
- Complete range of construction equipment necessary to satisfy the most difficult and exacting field construction requirements.
- Fabrication capabilities that meet the requirements of ASME Boiler and Pressure Vessel Codes, TEMA, HTRI, and API.
- Construction materials that include carbon and alloy steels, alloys, clads, and pure metals.
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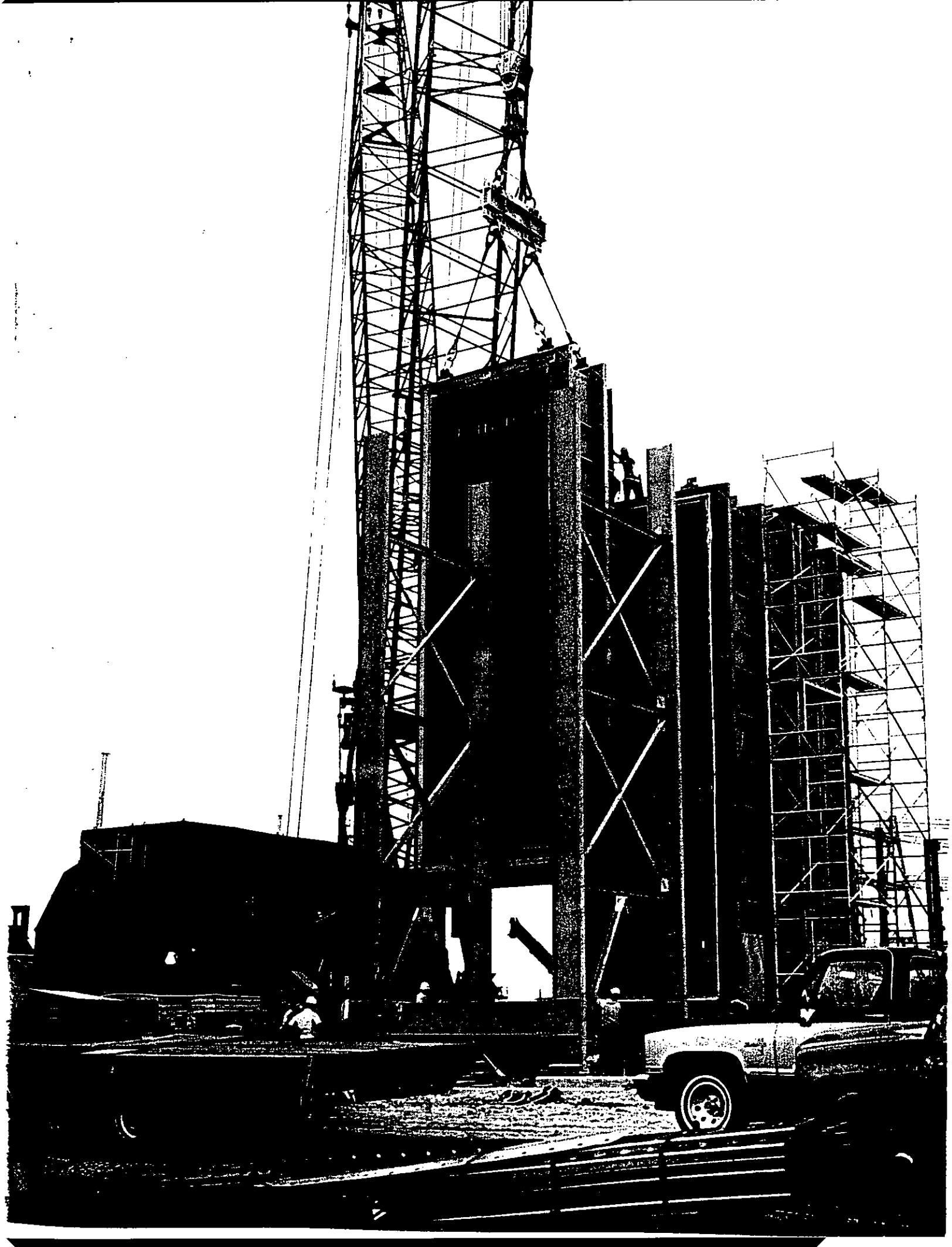
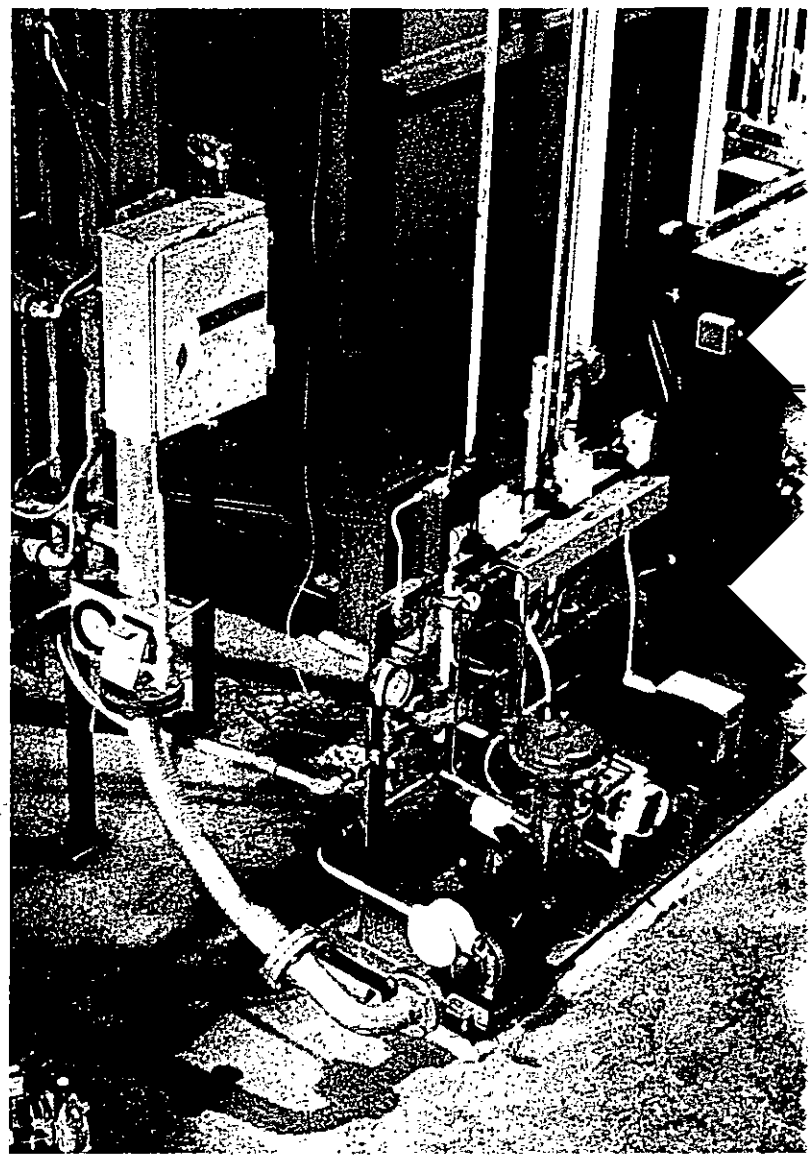
- In depth experience based on past service to the chemical, petroleum, petrochemical, environmental, pharmaceutical, brewing, pulp and paper, food, power, and munitions industries.
- Complete post weld heat treating facilities.
- A total quality assurance capability at the jobsite to meet the most stringent code requirements.

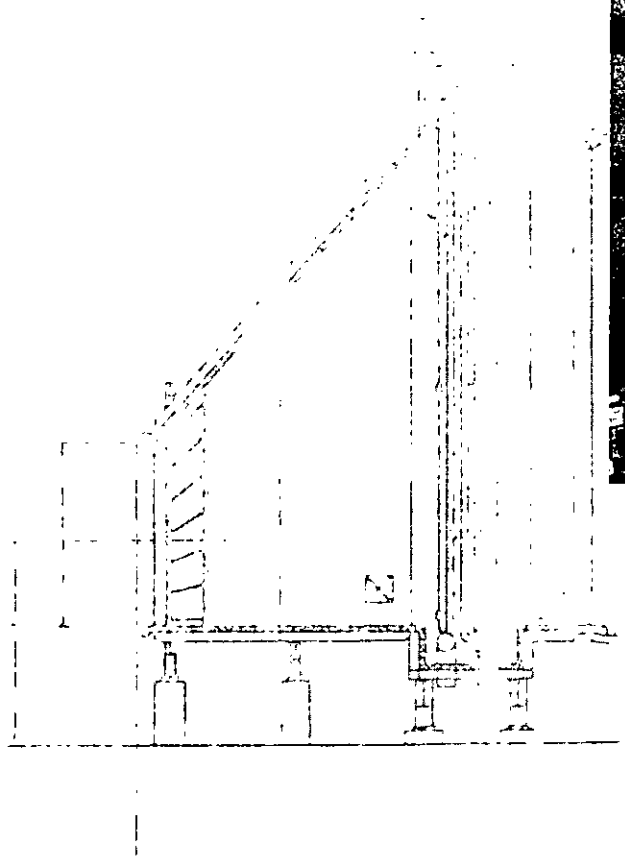


MAINTENANCE

We offer a variety of maintenance related programs and services including:

- Commissioning and performance testing.
- Extended warranty with inspection and preventive maintenance at pre-determined regular intervals.
- All encompassing maintenance contracts for complete heat recovery systems.
- Emergency service upon request.





Your Inquiries are Invited

For Design Recommendations and Cost-Saving Estimates.

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- ☐ Nooter Construction Co. Brochure
- ☐ Bulletin #101 — Corrosion Data Charts
- ☐ PLYWALL® Vessels
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- ☐ Heat Exchangers
- ☐ Plant Survey Report
- ☐ Delivery Date Calculator
- ☐ Flange & Coupling Selector

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COGENERATION SYSTEMS, INC.

P.O. Box 66888, St. Louis, MO 63166-6888
Telephone: (314) 957-7800
FAX: (314) 966-6989
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FAX: (314) 966-6889
TELEX 44-949
Offices: 3630 South Geyer Road, Suite 310
St. Louis, Missouri 63127-1235

ATTACHMENT 3

Table A. Estimated Emissions of Toxic Air Pollutants, Tropicana Cogeneration Facility

Pollutant	Emission Factors (pg/J)		Natural Gas Burning Emissions						Fuel Oil Emissions	
			Gas Turbine		HRSG		Auxilliary Boiler		Auxilliary Boiler	
	Natural Gas	Distillate Oil	(lb/hr)	(TPY)	(lb/hr)	(TPY)	(lb/hr)	(TPY)	(lb/hr)	(TPY)
Benzo(a)pyrene	N/A	0.4	-	-	-	-	-	-	0.0001	0.0001
Cadmium	N/A	71.8	-	-	-	-	-	-	0.0263	0.0189
Chromium	N/A	29	-	-	-	-	-	-	0.0106	0.0076
Manganese	N/A	0.6	-	-	-	-	-	-	0.0002	0.0002
Nickel	N/A	290	-	-	-	-	-	-	0.1061	0.0764
Polycyclic Organic Matter (POM)	10	30	0.0099	0.043	0.0024	0.011	0.0037	0.016	0.0110	0.0079
Selenium	N/A	10.1	-	-	-	-	-	-	0.0037	0.0027
Vanadium	N/A	30	-	-	-	-	-	-	0.0110	0.0079

N/A = Emission factor not available

ATTACHMENT 4

COEN DAF MULTI-STAGED LOW NOx BURNERS

Represented by

Warren H. Seaver Co.

Four Commerce Park Square
23200 Chagrin Boulevard — Cleveland, Ohio 44122
Phone: 216-292-8123

...for single or multiple burner units

COEN COMPANY, INC.

COEN COMPANY, INC.

Designed to Solve Your Emission Problems

Engineered For NOx Reduction

The DAF's Distributed Air Flow multi-staging ability to reduce NOx with minimum flame length is particularly important. Competitive designs which introduce fuel or air around the main flame body can result in excessively long flame lengths in today's modern boiler design. The DAF burner, on the other hand, was specifically designed with high space heat release/limited boiler furnace lengths in mind.

The DAF burner consists of two separate air zones. The primary air stream establishes a strong, central recirculating air zone directly downstream of the Coen "isokinetic" spinner, which aids in burner stability throughout the burner firing range. The secondary air zone employs adjustable swirl which is used in shaping the burner flame to optimize furnace conditions and NOx levels.

Coen's "isokinetic" spinner generates a strong recirculation zone, assisting in NOx reduction. This zone is essentially a source of flue gas that results in local entrainment of gasses by fuel jets to reduce thermal NOx. In addition, the proprietary gas/oil nozzle designs help to reduce fuel NOx hence the term "DAF" multi-staged burner.

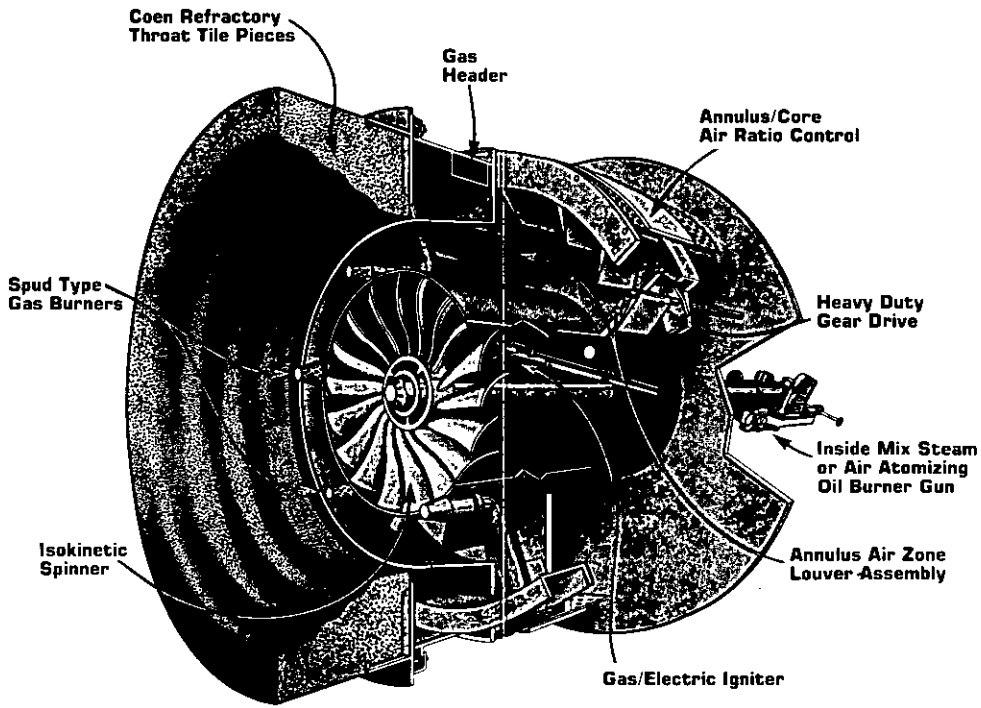
Coen DAF Low NOx Burner

The Coen DAF multi-staged low NOx Burner is designed for low NOx applications on single or multiple burner units. For many applications, the burner is capable of firing over a 10:1 range.

Combining selected features of Coen's DAZ register and CPF low excess air burner, the new DAF's multi-staged design can deliver up to 60% thermal NOx reduction. When combined with other Coen low NOx techniques, reductions of 80% or more are possible.

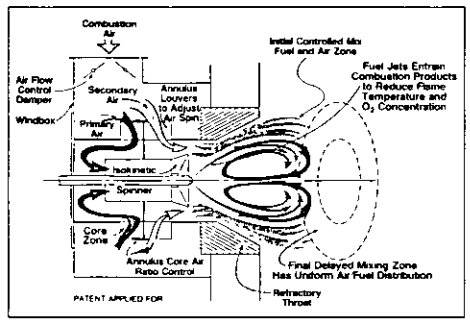
Design features

- DAF can be used with other Coen Low NOx techniques such as flue gas recirculation, front or side wall NOx ports and low excess air operation.
- Adaptable to burning gaseous and/or liquid fuels such as natural gas, refinery gas, hydrogen, coke oven gas, landfill gas, light and heavy fuel oils, refinery pitch, coal/water slurries, and waste fuel streams.

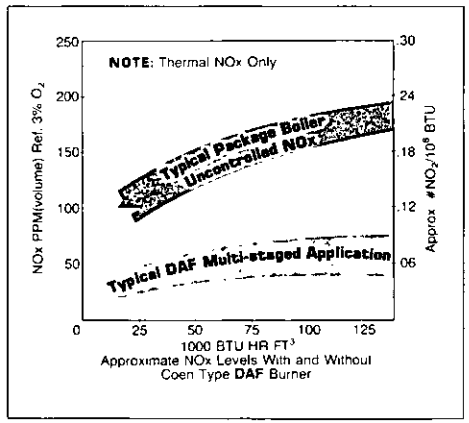


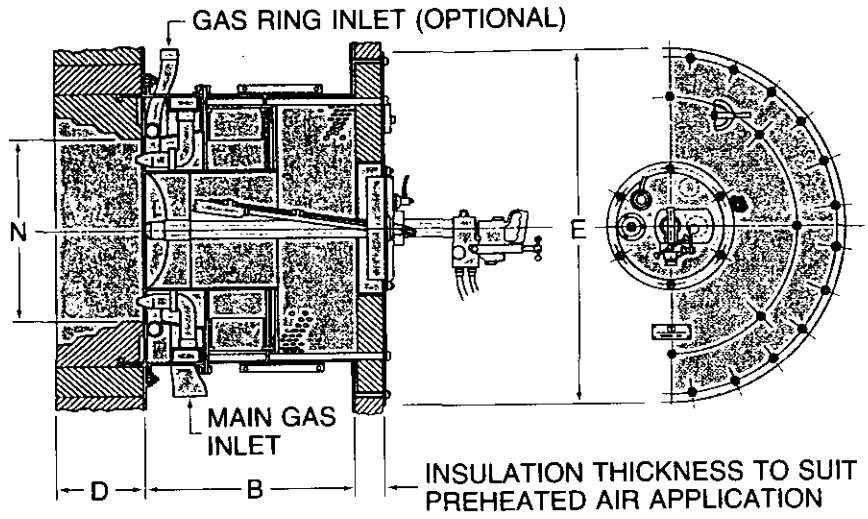
- Can be packaged with wind box, forced draft fan, piping, burner management and controls for both integrated multi-burner set up or in Coen's "Fyr Compak" single or dual burner configuration.
- Particulates will typically be well below the EPA required 0.1 pound/million BTU with fuel oils containing 0.1 ash or less. Guarantees can be made based on analysis of furnace/fuel conditions by Coen application engineers.
- A wide variety of atomizers are available for liquid fuels such as light grade fuel oil to heavy fuel oils and coal/water slurries, employing steam, air or natural gas atomization.
- For remote operation on multi-burner applications, atomizers can be equipped with pneumatically-operated automatic retract assemblies.
- For automatic operation on multi-burner applications, DAF can be equipped with a pneumatically-operated slicing barrel damper assembly to prevent combustion air from bypassing through non-operating burners.
- Can simultaneously fire liquid and gaseous fuels for reducing operating expenses.
- Multiple gas spuds arranged in an axial position to minimize NOx formation. Each spud has a screwed connection facilitating spud adjustment at start up or spud replacement if fuel conditions change at a later date. External cane-type spuds can be used for dirty gas applications. They can be fitted with individual shut-off cocks for changing or cleaning without system shut down.

Coen Type DAF Operation of Multi-Staged Low NOx Burner



Performance Comparison Chart





DAF Burner Dimensions

	N (Nominal Burner Size)											
	14-15	16 ½	18-20	22	24	26	28	30	32	34-36	39	42-45
B-Min. Burner Length	20	21	25	26	32	32	34	38	38	44	47	57
D-Throat Depth	13 ½	13 ½	13 ½	13 ½	13 ½	13 ½	13 ½	13 ½	13 ½	13 ½-22 ½	22 ½	22½
E-Front Plate Dia.	31¾	36	36	36-48	48	48	48	48	58	58	65	65

NOTES: 1. All dimensions are in inches.
2. Throat depths are typical, actual depth may vary with application.

Other Coen Low NOx Design Techniques

Side Wall Ports: Located in the boiler side walls, this form of air staging is particularly useful at reducing fuel bound NOx from high nitrogen content fuel oils.

Front Wall Ports: Used on single or multiple burner applications where generous furnace dimensions are available. Provides moderate thermal NOx reduction. Ports located around periphery of burner.

Low Excess Air: Multiple burner, low space heat release applications. Small to moderate NOx reduction.

Biased Firing: Employed on multiple burners only, oftentimes with other types of low NOx techniques. Some burners fired fuel rich, some lean. Moderate NOx reduction.

Flue Gas Recirculation: Extremely effective at reducing thermal NOx, commonly used on gas only/light oil applications for maximum NOx reduction.

Coen is dedicated to being the leader in low emission burners for the boiler/burner industry. Coen's unparalleled years of experience in industrial/utility markets has led to the development of a multitude of low NOx burner techniques unmatched in our traditional boiler markets. Whether for a new boiler application or a retrofit, Coen engineers will provide the low NOx technique most economical for your installation, while maintaining minimum emission levels of NOx, CO, hydrocarbons and particulates.

Since 1912, Coen Company has specialized in the design, manufacture servicing and maintenance of burner equipment and combustion systems. With over 10,000 installations world-wide, Coen equipment and systems provide optimum performance.

For more information on Coen burners and combustion systems, contact:

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ATTACHMENT 5

NO_x CONTROL OPTIONS
FOR
HRSG AND AUXILIARY BOILER

1.0 DESCRIPTION OF CONTROL ALTERNATIVES

The comment identifies four NOx control options to be evaluated for the proposed heat recovery steam generator (HRSG) and auxiliary boiler: a) water/steam injection, b) selective non-catalytic reduction (SNCR), c) NOx-out (urea injection), and d) thermal de-NOx process.

Water/steam injection has been extensively applied to gas turbines for NOx control. The injection acts to lower the peak flame temperature within the combustor, which reduces "thermal" NOx (i.e., the NOx formed by the reaction of nitrogen and oxygen in the combustion air to form NOx at high temperatures). The technique has been applied to gas turbines because fuel and efficiency penalties are only about 1 percent, and no significant operational problems, or reduced equipment life, result for modern gas turbines. However, the technique is not appropriate for stationary combustion equipment (i.e., HRSG and boiler) because of the much higher fuel and efficiency penalties of about 10 percent, and potential for effects upon equipment operation and life (e.g. corrosion).

The other three processes identified in the comment, SNCR, NOx-out and Thermal de-NOx, are all essentially the same process. The SNCR process has been patented by Exxon Engineering and Research under the name of "Thermal DeNOx". In this process, ammonia is injected into the gas stream at a location where temperatures are in the range of 1,600°F to 2,000°F. Within this temperature range, ammonia will selectively react with NOx to form nitrogen and water. NOx emission reductions between 35 to 70 percent can be achieved. The efficiency is dependent upon and limited by the flue gas temperature, residence time of the gases at the critical temperature range,

2.2 Economic Evaluation

An economic evaluation of SNCR and NOx-out is presented in Table A. The analysis is based upon a 50% NOx removal with each process (a highly optimistic figure). The costs are based upon the same assumptions as presented in the original permit application. As shown, the cost of SNCR on the GT/HRSG is $2,756/ton. This figure, although lower than the cost effectiveness of SCR, is still well above the FDER guideline for NOx of $1,000/ton. For the auxiliary boiler, the cost effectiveness of SNCR is over $5,000/ton. Based upon this economic evaluation, the use of SNCR on the proposed Tropicana facility is rejected.

2.3 Environmental Evaluation

The major environmental concerns with the application of SNCR is the potential for ammonium bisulfate formation and ammonia slip. Ammonium bisulfate formation would only be a problem when burning distillate oil, due to the sulfur in the oil. Formation of this material and subsequent deposition on the downstream air preheater and other boiler components can cause severe corrosion and fouling over an extended period of time.

Ammonia slip refers to the release of free ammonia in the exhaust gas stream due to the incomplete reaction of ammonia with the NOx. Ammonia slip occurs with both Thermal DeNOx and NOx-out processes. Emissions are reported to range from 10 ppm to as high as 50 ppm. The odor threshold for ammonia is 20 ppm, so there exists a distinct possibility of odor emissions from the process with this control technique.

the degree of turbulence and mixing of the gas stream and ammonia, ammonia/NOx ratio, and the initial NOx concentration.

The NOx-out process was developed by the Electric Power Research Institute (EPRI) and is marketed by Fuel Tech, Inc. This process is essentially the same as SNCR, but uses a urea-based aqueous solution instead of ammonia. Commercial applications of this process are presently limited. NOx removal efficiencies reported with NOx-out are in the range of 30 to 70 percent.

2.0 EVALUATION OF CONTROL TECHNOLOGIES

This evaluation will consider the SNCR processes described above as a single control technology, since the processes are nearly identical.

2.1 Technical Feasibility

SNCR is generally applicable to gas and oil-fired boilers, but is limited to applications with low sulfur concentrations in the gas stream. With high sulfur concentrations, ammonium bisulfate will form, which can foul the downstream air heater, economizer, and other boiler components.

The control efficiency of the process is dependent in part upon the initial NOx concentration. The NOx levels in the HRSG and auxiliary boiler gas streams will be low based upon the already low NOx limits of 0.1 $lb/10^6$ Btu (0.2 $lb/10^6$ Btu for oil burning in the auxiliary boiler). The calculated NOx concentrations are 30 ppm for the GT/HRSG, 40 ppm for the auxiliary boiler (gas) and 80 ppm for the auxiliary boiler (oil). At these very low NOx concentrations, the control level achievable by the process is highly uncertain, and would probably be below 50% removal.

References

Air Resources Board and South Coast Air Quality Management District. April, 1987. A Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators and Process Heaters. Prepared for the Technical Review Group.

Radian Corporation. 1987 Symposium on Stationary Combustion Nitrogen Oxide Control. CS-5361, Volume 2, p. 43-1.

U.S. Environmental Protection Agency. 1983. Control Techniques for Nitrogen Oxides Emission From Stationary Sources (Revised Second Edition). EPA-450/3-83-002.

Table A. Cost Components and Effectiveness for SNCR and NO_x-Out on the GT/HRSG and Auxiliary Boiler

	GT/HRSG	Auxiliary Boiler+
Cost Component		
Capital Cost	$964,000	$384,000
Annualized Capital*	270,000	108,000
Maintentance	29,000	12,000
NH3	60,000	13,000
Steam	68,000	15,000
Electricity	6,000	1,000
Total Annualized Cost	$433,000	$149,000
NO_x Emissions before Control (tons/yr)	314.2	57.6
NO_x Removal Efficiency (%)	50	50
NO_x Removed (tons/yr)	157.1	28.8
Cost Effectiveness ($/ton NO_x)	$2,756	$ 5,174

* Based on a rate of return of 20%, interest on debt of 11%, a Federal tax rate of 34% and state taxes at 9.6%, over 20 years.

+ Based on 100% natural gas firing

Sources: CARB and SCAQMD, 1988b
KBN, 1988