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STUDY OF EXHAUST EMISSIONS FROM NATURAL GAS PIPELINE COMPRESSOR ENGINES

by

Charles M. Urban

Karl J. Springer

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Project PR-15-61

Prepared for

Pipeline Research Committee
of the
American Gas Association

February 1975

SOUTHWEST RESEARCH INSTITUTE
SAN ANTONIO CORPUS CHRISTI HOUSTON

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Approved:
Karl J. Springer
Karl J. Springer, Director
Department of Emissions Research

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FOREWORD

This project was under the overall supervision of Sam J. Cunningham, Southern California Gas Company, Chairman of the Supervisory Committee on NO_x Research for Prime Mover Operations (PR-15-61). Three members of the supervisory committee were selected to provide technical guidance, coordination, and cooperation at the various participating gas transmission companies. Members of this technical subcommittee included Chairman James R. Hatfield, Northern Natural Gas; Don Scott, Columbia Gas System; and Walker Meacham, Texas Gas Transmission. Charles Newton, Colt Industries; and Phillip Myers, University of Wisconsin, participated in this project as representatives of the Diesel Engine Manufacturers Association.

This project was entitled "Study of Exhaust Emissions from Natural Gas Pipeline Compressor Engines". The Southwest Research Institute project designation was 11-3438-002 and was conducted from March 1974 through February 1975. The engineer responsible for the study was Charles M. Urban and the overall project supervisor was Karl J. Springer.

ABSTRACT

This study of exhaust emissions from natural gas pipeline compressor engines consisted of three tasks: estimation of national emissions impact, control technology assessment, and informational activities. Determination of emissions impact involved obtaining and processing available data on operation of and emissions from natural gas compressor engines. The control technology assessment presents a summary review of existing data on the control of NO_x emissions from natural gas compressor engines. The informational activities involved presentations of the results of the baseline emission survey (the initial phase of this project) to gas turbine and reciprocating engine manufacturers, the EPA and other organizations as requested by the NO_x Supervisory Committee.

EXECUTIVE SUMMARY

This phase of AGA project PR-15-61 involved three primary areas: (1) estimation of national emissions impact, (2) control technology assessment, and (3) informational activities. Each of these areas is summarized as follows:

EMISSIONS IMPACT - It is estimated that in 1973 the total gas utility industry operated 85 billion brake horsepower-hours and produced approximately 784,000 tons of NO_x, 100,000 tons of CO, 293,000 tons of total HC and 15,000 tons of non-methane HC. These values represent 3.6 percent of the NO_x, 0.1 percent of the CO and 1.1 percent of the HC from all man-made sources and 7.2 percent of the NO_x, 0.4 percent of the CO and 2.5 percent of the HC from stationary sources (all sources not classed as transportation). Percentages are based on national emissions estimates for 1971, the latest data available. About five percent of the HC emissions from the gas industry is non-methane. Gas turbines, which account for 25 to 30 percent of the 14,850,000 total gas utility industry installed compressor horsepower, produced only 5 percent of the 784,000 tons of NO_x. Emissions of HC and CO from the gas utility industry are negligible and the NO_x is about half that estimated in a 1969 study that was widely distributed.

EMISSION CONTROL - For gas turbines both "wet" and "dry" methods were found, from available data, to be effective for reducing NO_x emissions. Water injection, a wet method, was found to generally reduce NO_x emissions by about 80 percent at a water flow rate equal to the fuel flow. The maximum reduction in NO_x emissions that was reported in the literature for "dry" methods was 42 percent. Of the two methods, the "wet" methods appear to be the only control approach currently able to meet the 55 ppm NO_x level specified in the suggested standard.

For reciprocating gas engines, most emission control evaluations that have been reported involved variations of engine operating parameters such as torque and speed. It was found, in most of these evaluations, that the change in the operating parameter resulted in a change in air/fuel ratio which was either partially or totally responsible for the NO_x reduction. Air/fuel ratio appears to be the single most important parameter affecting reciprocating gas engine NO_x emissions. From the available data, it appears that many of the NO_x control methods, such as exhaust gas recirculation, water induction and injection, catalysts and stratified charge, have limited application or are not appropriate to reciprocating gas engines.

INFORMATIONAL ACTIVITIES - The results of the baseline emissions survey, conducted in the initial phase of this project, have been separately presented to the gas turbine manufacturers, the reciprocating engine manufacturers, and the Environmental Protection Agency. Other presentations of the baseline survey that either have or will be made include three different industrial and professional organization meetings and conferences.

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I. INTRODUCTION

During 1972 and 1973, the American Gas Association (AGA) sponsored a project with Southwest Research Institute (SwRI) to determine the emission rates of reciprocating engines at rated speed and load and gas turbines as they were operating under on-site field conditions. The results of the baseline survey(1) can be obtained from AGA as catalog number L22274. In early 1974, AGA sponsored a continuation of this project which, as subsequently revised, involved: making presentations of the baseline data to manufacturers and the Environmental Protection Agency (EPA), using the baseline survey data in a determination of emissions impact, and assessing methods for controlling NO_x emissions. This project directly involved only those natural gas reciprocating engines and gas turbines over 1000 horsepower.(2)

A. Approach

Each of the major natural gas reciprocating engine and gas turbine manufacturers, all of the AGA member companies, the EPA, and the statistical section of AGA were contacted and asked to provide input information in their respective areas. The contacts involved letters which were generally followed up with a telephone call; and in several instances visits were made. In general, the overall response (discounting several rather long delays in obtaining the information) was very good.

Upon receipt of all the reasonably obtainable emissions and engine operating data, a computer program was written and the data processed to determine the emissions impact of the piston and gas turbine engines used in natural gas transmission. Concurrent with the emissions impact evaluation, data was collected on methods of emissions control for natural gas reciprocating engines and gas turbines. This compiled data was then summarized into an assessment of the state-of-the-art in emissions control of reciprocating engines and gas turbines used in natural gas compression.

B. Participation in Meetings and Conferences

On February 21, 1974, members of the AGA NO_x Supervisory Committee, SwRI personnel, and representatives of the Diesel Engine Manufacturers Association (DEMA) met in Houston to discuss plans for the continuation of AGA project PR-15-61.

On August 15, 1974, members of the NO_x Technical Subcommittee, SwRI personnel and a DEMA representative met in Dallas to review the current project and to formulate a continuing project.

On October 17, 1974, the NO_x Supervisory Committee, SwRI personnel, and a DEMA representative met in Houston to discuss the project status. The primary discussion involved the results of the emission impact evaluation, its significance and the proper method for disclosure.

In February or March, 1975, the NO_x Supervisory Committee plans to meet with SwRI personnel to discuss this final report and possible plans for a continuing project.

In addition to these meetings, a briefing and project discussion was held on June 28, 1974 in San Antonio with Don Scott, Columbia Gas System; James Holden, AGA; and Charles Urban, SwRI, in attendance. Several other briefings were given by Charles Urban during on-site visits by James Holden throughout the course of this project.

II. ESTIMATION OF NATIONAL EMISSIONS IMPACT

The object of this task was to utilize baseline emissions data obtained in the previous phase of project PR-15-61 and from engine manufacturers, along with available population and usage statistics, to estimate the role of the gas transmission prime movers as a source of NO_x, HC, and CO emissions. The emissions impact of engines over 1000 horsepower in use by AGA member companies was determined using operating statistics supplied by the gas companies. Total gas utility national emissions impact was estimated by extrapolation of the values determined for the AGA companies directly included in this project.

A. Presentation of Available Emissions Data

Data on emissions from gas turbines and piston engines as used in gas transmission service came from a number of sources. The primary source of emissions data, however, was the preceding phase of this project (PR-15-61).[1] Several reasons for this selection as the primary source include: the emissions were determined from engines which were in actual field operation, a relatively large number of engines at many different locations were evaluated, and a significant amount of engine operating data was reported along with the emissions.

These emissions data were presented to the engine manufacturers for review and comment. The piston engine manufacturers, with a few minor exceptions, were in general agreement with the emissions values. This general agreement was expressed during personal visits and in a letter from the Diesel Engine Manufacturers Association (DEMA) (note - the gas engine manufacturers also manufacture diesel engines). The gas turbine manufacturers, however, generally felt that the PR-15-61 emission values for oxides of nitrogen (NO_x) were somewhat lower than they would expect. This lack of agreement on gas turbine emissions will be discussed in more detail later.

A number of atmospheric and engine operating factors were found to affect the level of emissions. Several of these factors are: humidity, ambient (or more specifically, engine manifold) temperature, altitude (or barometric pressure), and engine operating torque. It was readily determined that emission corrections for these factors have not been established for natural gas fueled engines. In this project some correction factors were assumed in areas where a reasonable amount of test data was available. In other areas (including ambient temperature) no correction factors were applied.

Three exhaust pollutants: oxides of nitrogen (NO_x), carbon monoxide (CO), and hydrocarbons (HC) were included in this project. No attempt was made to evaluate sulfur compounds, particulates, or any of the other possible exhaust constituents. The hydrocarbon compounds were broken down into methane and non-methane hydrocarbons. The hydrocarbons of concern are generally considered to be only the non-methane portion. To remain consistent with current standard reporting, however, "hydrocarbons" in the report will always indicate "total hydrocarbons", unless prefixed by "non-methane".

1. Sources of Emission Data

The most important sources of emissions data obtained for this project are given in Table 1. Although the quantities from each source are dependent on the model breakdown and the definition of what constitutes emissions data, this table does illustrate the significance of the PR-15-61 emissions data. In addition to those listed, a few emission measurements were discussed over the telephone or during visits, but actual release of these data could not be obtained. In a few cases the request was made that the actual data or the source not be released. This request has been followed and some of the data presented in this report has been coded. This coded data, however, has been included for information only and has not directly entered into the development of the emission factors assumed for use in this project.

2. Consistency of the Data

A difficulty encountered with much of the emissions data obtained in this project (other than the PR-15-61 data) was that generally only processed data was available and no consistent criteria were used in the processing. For example, some emissions were reported in grams per brake horsepower hour (g/bhp-hr), some in pounds per million BTU heat input (lb/mm BTU), some in parts per million (ppm), some in ppm corrected to 15 percent oxygen, etc. In addition, some used the lower heating value (LHV) of the fuel and some used the higher heating value (HHV) and it is not always clearly indicated which was used. Efforts are being made to correct this situation, one example being the Exhaust Emissions Measurement Procedure developed by DEMA[3]. The initial phase of this project[1] reported the emissions data in several different ways. For the determination of emissions impact, brake specific emission factors (g/bhp-hr) have been used. This selection was made solely on the basis of this factor being the most compatible with the available engine operating information.

It was mentioned previously that the gas turbine NO_x emissions measured in PR-15-61 are generally lower than those reported by the manufacturers. The comparative values are shown in Table 2. Generally, the manufacturers' stated values are about 50 percent greater than the PR-15-61 values. Table 3 shows a comparison of the PR-15-61 values and the values that were used in the study conducted by the Shell Development Company[4]. Using data from different sources, the overall average values for gas turbines over 9,000 hp as used by Shell and as determined

TABLE 1. PRIMARY SOURCES OF EMISSIONS DATA

Piston Engines			
	Number of		
Source	Models*	Engines	Comments
AGA Project PR-15-61	18	59	Measured in the Field
Natural Gas Trans. Co.	11	19**	Measured in the Field
Engine Manufacturers	11**	20 (Est.)**	-

Gas Turbines			
	Number of		
Source	Models***	Engines	Comments
AGA Project PR-15-61	4	8	Measured in the Field
Natural Gas Trans. Co.	2	4	Measured in the Field
Turbine Manufacturers	4	?	Estimates given on additional models

* Using the model breakdown in the AGA Directory of Reciprocating Gas Engines[2]

** These include measurements made using procedures which are not applicable to this project

*** Basic model designation is used (i.e., GG3, Model 3000, etc.)

TABLE 2. GAS TURBINE NO_x EMISSION COMPARISONS

Mfg.	Model	NO_x in	Value: PR-15-61	Value: Mfg.	Comments
GE (I)	M3912RC	lb/mm BTU	0.44	0.61*	Corr. to Rated Load
GE (I)	M3142RC	"	0.41	0.67*	"
GE (I)	3000RC	"	0.23	0.35 avg*	"
GE (I)	3000 RC	gm/bhp-hr	1.7 avg.	-	2.5 at company 13
GE (A)	LM 2500	ppm (observed)	66	80	75% of Rated
P & W	GG3	ppm (observed)	34	50***	Corr. to Rated Load
Solar	Saturn	ppm (15% O_2)	51	59***	Rated Load
Solar	Saturn	lb/mm BTU	0.14	0.23***	" "

* Estimates claimed to be based on measurements
** Estimates - only measurements known to be made are in PR-15-61
*** Stated to the upper limit

Note: GE (I) and (A) indicate Industrial and Aircraft type turbines, respectively.

TABLE 3. COMPARISON OF GAS TURBINE NO_x EMISSION VALUES

Specific Emissions, grams/bhp-hr					
Shell Report(4)			Company 13	PR-15-61**(1)	
Turbine	BHP	NO_x	NO_x	BHP	NO_x
A	6200	3.2*			
			2.5*	-	-
B	6900	2.8*			
C	1100	0.8	-		
				1,050	0.8
D	1100	1.0	-		
				10,500	1.3
E	13,950	1.7	-		
				12,000	1.2
F	13,950	1.5	-		
				20,000	1.5
G	14,700	0.9	-		
				9,300	1.1
H	14,700	1.6	-		
				9,100	1.8
I	14,700	1.5	-		
				11,100	1.6
Over 10,000 BHP		1.4 Avg.			1.4 Avg. ***

*Shell data appears to have been obtained from Company 13. Company 13 data shown is average value adjusted for humidity and load.

**Values adjusted to nominal rated load and 44 grains of water per pound of air humidity.

***Sales weighted average comes out the same.

in PR-15-61 are essentially identical. It should be pointed out that of the manufacturers' stated values in Table 2, the emissions for the P&W GG3 have never been measured except in PR-15-61, the Solar Saturn value was given as a maximum expected value, the GE (I) models 3XXX are "reportedly based on measured values" and the GE (A) LM2500 are reported to be measured values. It is of interest that the manufacturer's LM2500 measured values are in fairly close agreement with the PR-15-61 values.

The P&W GG4 is used as a peaking unit by the electrical power industry, and emission measurements have been made on several units. NO_x emission values reported in reference 5 have been reviewed and the data on the three units, which were reported in ppm, are as follows:

Model	% Peak Load	% Rated Load	NO_x, ppm
GG4A-8	72	90	65
GG4A-8	84	105	52
GG4A x8	100	125	35

From this table, the trend of these three units with respect to load is opposite to the normal trend (normally higher load produces higher NO_x emissions). If this relationship were valid, the NO_x value at 100 percent load would be about 57 ppm which would calculate out to be about 2 grams/bhp-hr. However, at the 125 percent load, the values would be 35 ppm and about 1 gram/bhp-hr. These particular measured values do not help in establishing an emission factor for the GG4. Therefore, the GG4 emission factors were estimated from the PR-15-61 values for the GG3 taking into account the somewhat higher firing temperature in the GG4.

For piston engines some reproducibility and load factor relationships are shown in Tables 4, 5, and 6. The dashed lines labeled with an asterisk represent the relationship in which the percent change in NO_x brake specific emissions varies directly with the percent change in rated torque. The PR-15-61 values shown have been corrected for humidity (H) and/or load (LF) as noted to nominal rated conditions. Among the most significant variation was the measured NO_x values of the Clark TCVC engine which varied from 4 to over 15 g/bhp-hr at rated load. Fortunately the PR-15-61 value was 10, which is essentially directly in the center of the two extremes. In many other instances, however, reasonably good agreement was obtained (i.e., GMVA, V-250 and KVS).

TABLE 4. NO_x EMISSION COMPARISONS - COOPER BESSEMER

	Horsepower			NO_x,
	Rated	Test	Source	g/bhp-hr
GMV-10	1000	1160	#13[8]	20 to 30
GMV-10	(1350) mod	1403	PR-15-61	28
GMV-XX	-	Rated	C-B[6] Est.	15-17
GMV-TF	-	-	C-B	5
GMV-XX	-	LF Corr.	PR-15-61	20
GMVA-10	1350	1353	#13[8]	7.6
GMVA-XX	-	Rated	C-B[6]	15
GMVH-10	2000	1990	#13[8]	4
GMVH-XX	-	Rated	C-B[6]	13
GMWA-XX	-	LF Corr.	PR-15-61	10
GMWA-XX	-	Rated	C-B[6]	15
V-250	3400	LF Corr.	PR-15-61	15
V-250	-	Rated	C-B[6]	13

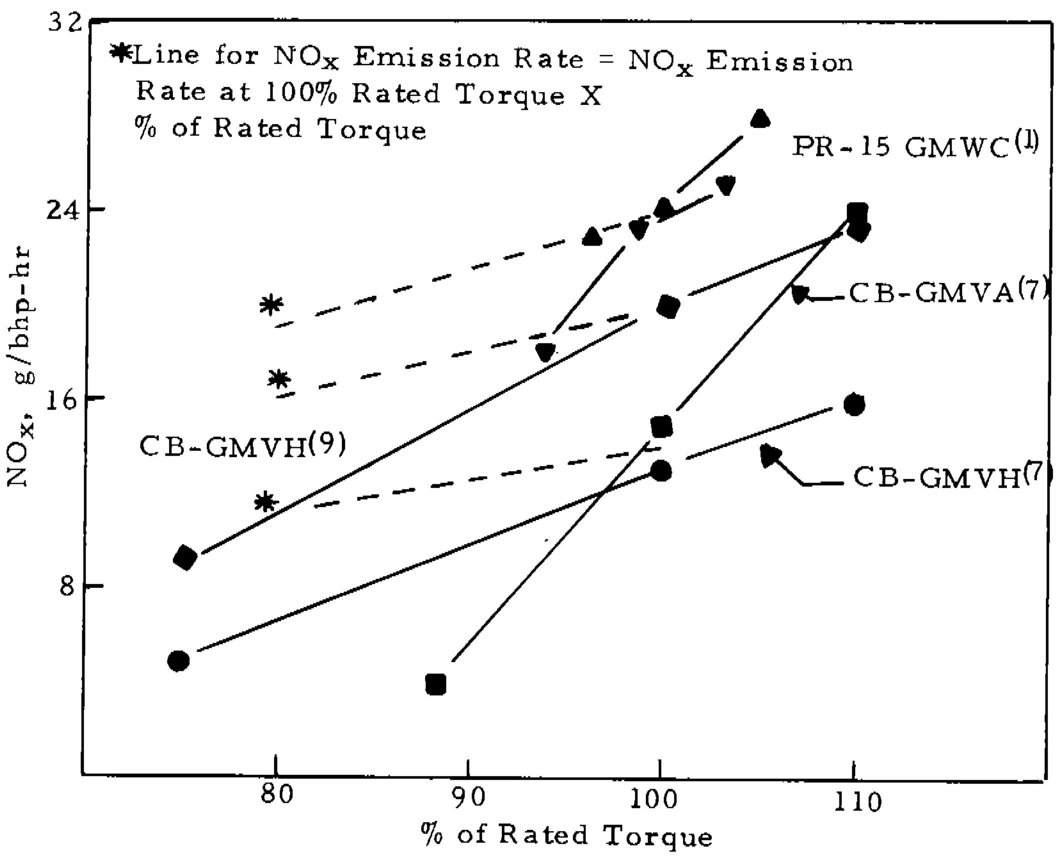


TABLE 5. NO_x EMISSION COMPARISONS - CLARK

	Horsepower		Source	NO_x, g/bhp-hr
	Rated	Test		
TLA-6	2000	2000	13(8)	12 avg
TLA-X	-	LF & H Corr.	PR-15-61	9 avg
TCVC	-	Rated	8(8)	4
TCVC	-	LF & H Corr.	PR-15-61	10
TCVC	-	Rated	02(8)	>15

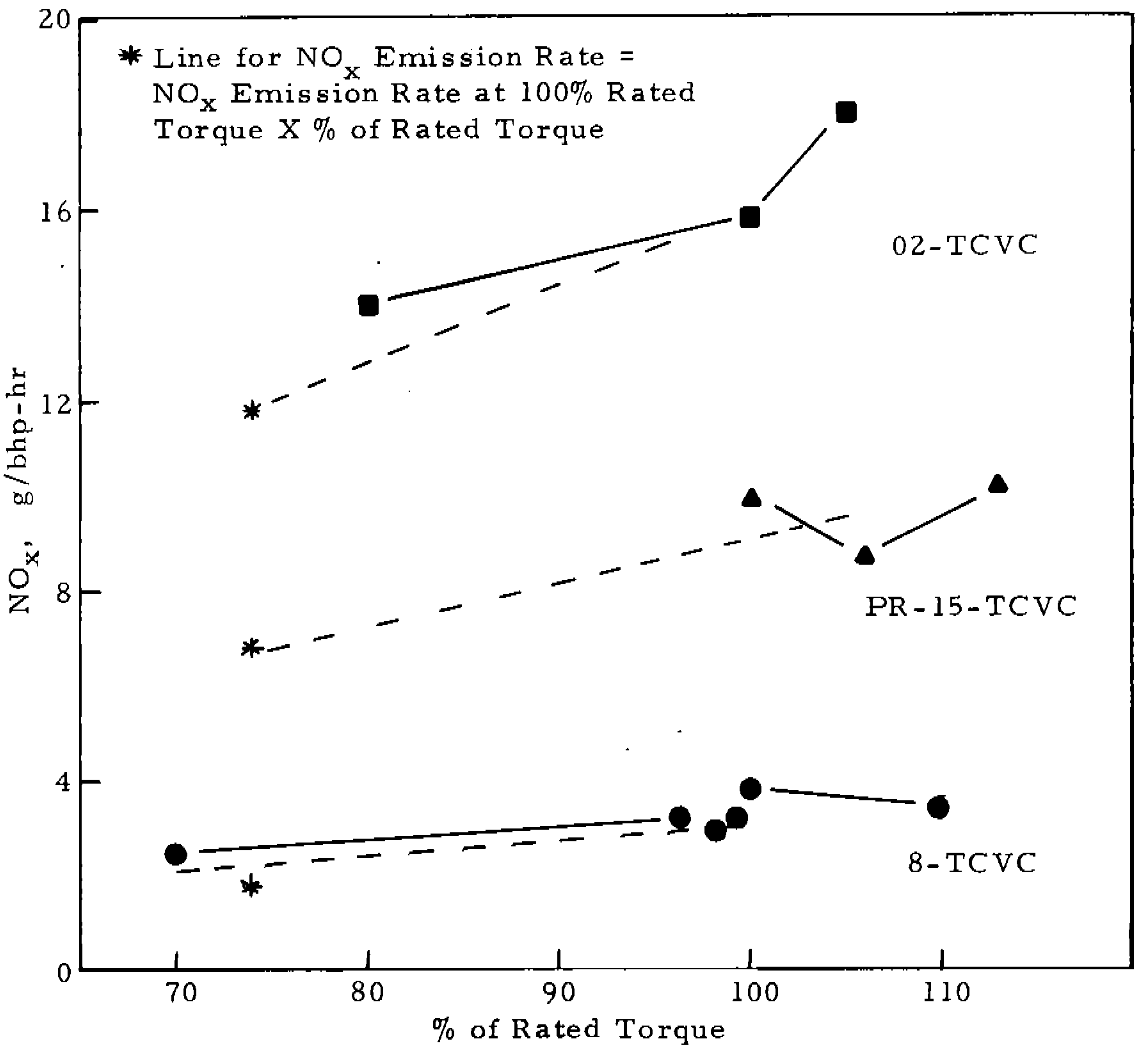
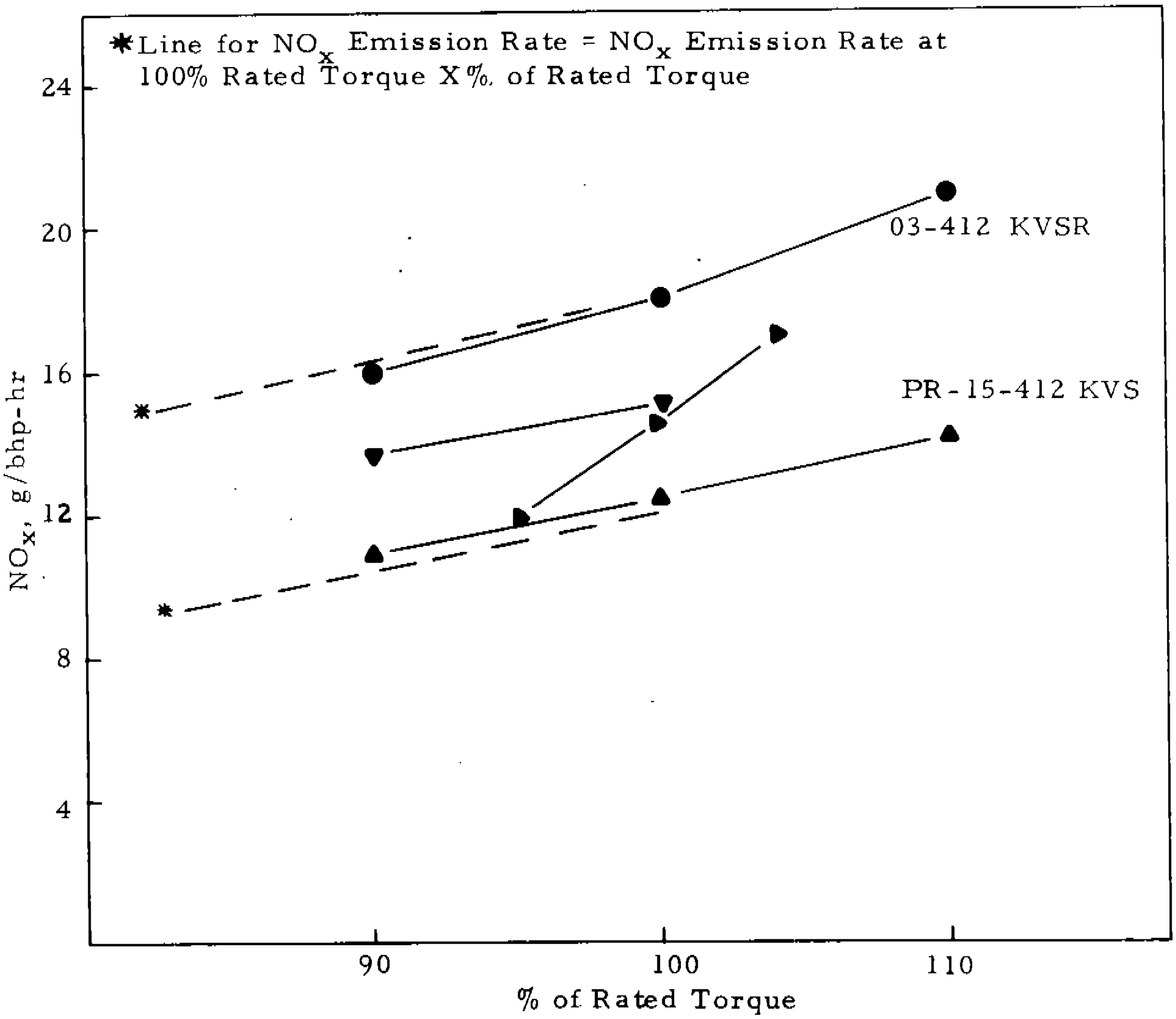


TABLE 6. NO_x EMISSION COMPARISON - INGERSOLL RAND

	Horsepower		Source	NO_x,
	Rate	Test		g/bhp-hr
KVS-412	2000	2120	13(8)	16
412-KVS	2000	LF & H Corr.	PR-15-61	15
412-KVSR	-	Rated	03(8)	18
KVR-512	4000	4000	13(8)	15
616-KVR	5500	LF & H Corr.	PR-15-61	11
KVT-616	4000	4040	13(8)	14
616-KVT	4000	LF & H Corr.	PR-15-61	7.5



3. Correction Factors

Several operating and atmospheric factors were found to have an observable effect on emissions; primarily the NO emissions. These factors include: engine load, ambient temperature and atmospheric humidity. Atmospheric pressure (as a function of altitude) can affect naturally aspirated reciprocating engines, but this factor is supposed to be compensated for by the turbocharger in turbocharged engines. Although these load and atmospheric factors can have a large effect on individual engine model emission factors, the effect of these factors on the overall nationwide emissions impact is expected to be small.

No published emission correction factors were found for use with natural gas fueled reciprocating engines and gas turbines. In areas where a reasonable amount of data was available, correction factors have been assumed for use in this study. Since individual engine models are affected differently, engine models can be found in which the factors for correction differ greatly from the values assumed in this study.

a. Load Factor - The load factor is defined as the ratio of the operating horsepower divided by the rated horsepower. After review of PR-15-61 emissions data and data received from the gas turbine manufacturers and other sources, the following formula and factors were assumed as being reasonably applicable for correction of emissions relative to operating load in gas turbines. These formulas are assumed to be applicable only within the range of rated load plus or minus 25 percent.

- Load Factor = Percent of Rated Load/100
- Emission at Rated Load (g/bhp-hr) = (Correction Factor) x Emission at Operating Load (g/bhp-hr)
- Correction Factor by Species

NO_x	HC	CO
$(L.F.)^{-0.5}$	$(L.F.)^2$	$(L.F.)^2$

The spread in the published data relative to load factor effect was significant.

With the reciprocating engines, due to the emission determination being made at or very near rated load and the actual in-service operation being near rated load, a load factor correction is not very important to this evaluation. Some load factor relationships were shown in previous Tables 4, 5, and 6. For this project, the assigned load factor corrections for reciprocating engines (g/bhp-hr) are as follows:

(a) Directly proportional to the load factor when due to a change in torque at constant speed

(b) Constant when due to a change in speed at constant torque

These load factor corrections for reciprocating engines are assumed to be applicable only over the range of rated load plus or minus ten percent.

These assumed load factor corrections are based on very limited data and do not represent an analytically acceptable correction factor on a model by model basis. One of the criteria used in the assumption of load factor corrections was to select factors which lie between no correction and the correction that the majority of the engine manufacturers would feel to be applicable. Based on discussions with several manufacturers, it appears the assumed correction factors meet this criteria.

b. Humidity Correction Factor - Figure 1 shows various published humidity relationships and correction factors. No published correction factor has been found for natural gas reciprocating engines. One DEMA member, based on information obtained over the telephone, uses a humidity correction factor for gas engines, and over the range of 25 to 75 grains H_2O/lb dry air it is essentially identical to the composite average shown on Figure 1. Also, the NASA-developed relationship for gas turbines[10], over the range of 25 to 125 grains, is almost identical to the composite average.

The humidity during the PR-15-61 emissions determinations ranged from 20 to 93 grains in data that was used for determination of emission factors (only two of the humidity values were above 78 grains). Therefore, for correction of the PR-15-61 reciprocating engine NO_x values, the relationship

$$K_r = \frac{1}{1 - 0.003\ (H-75)}$$

will be used. Optional relationships which produce results within 2 percent over the humidity range of 20 to 83 grains water/lb dry air (H) include:

$$K_r = e\frac{0.00272H}{1.226}$$

$$K_r = 1 + 0.003\ (H-75)\ .$$

For gas turbines, the NO_x emissions will be corrected to a humidity of 44 grains since this is the value used by the major gas turbine manufacturers. Therefore, for correction of the PR-15-61 gas turbine NO_x values, the relationship

$$K_t = \frac{1}{1 - 0.003\ (H-44)}$$

will be used. An optional relationship is:

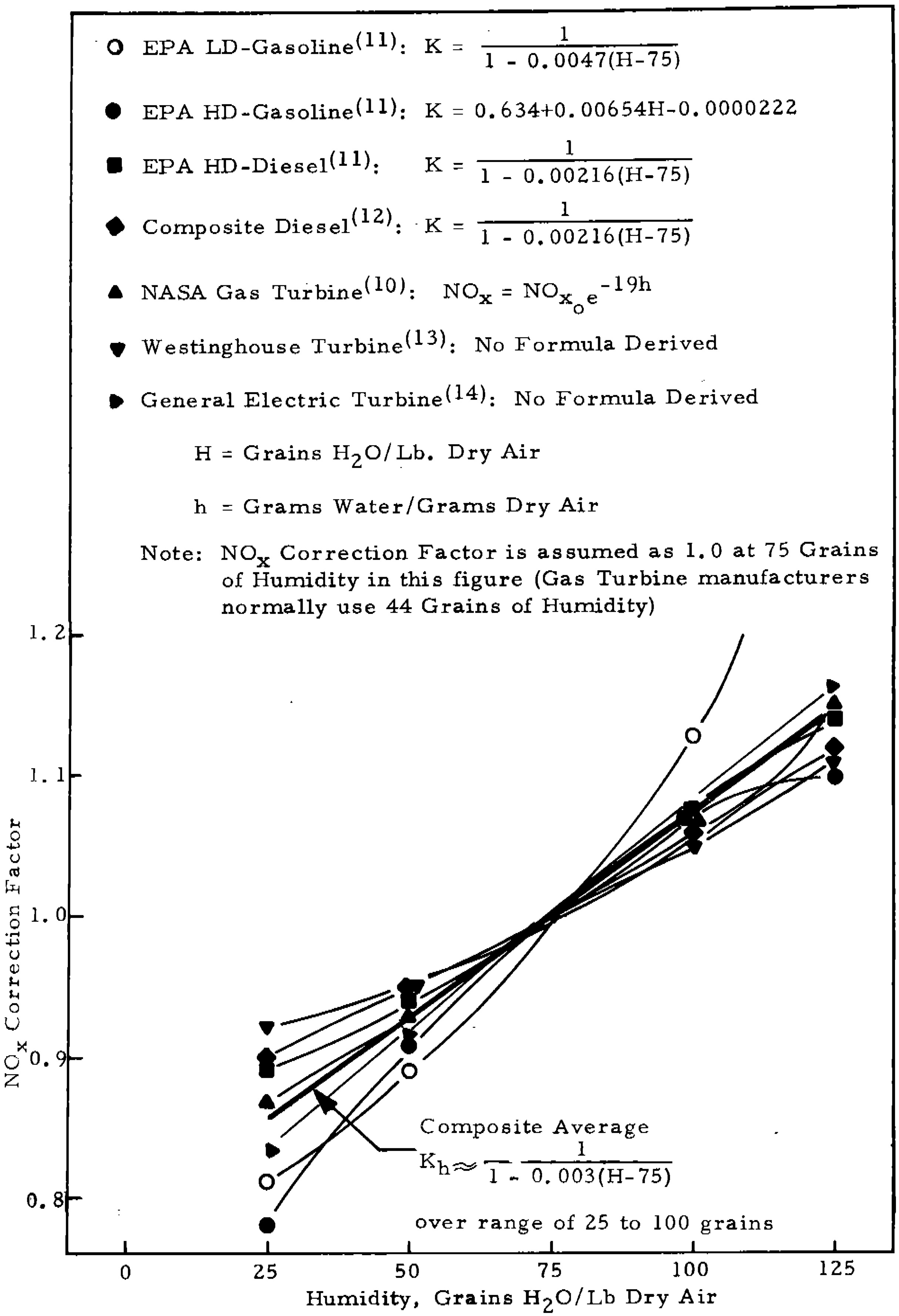


FIGURE 1. HUMIDITY CORRECTION FACTORS

$$K_t = e^{\frac{0.00272H}{1.127}}$$

Basically, over the range of about 25 to 100 grains of humidity, the NO_x correction factor is approximately 3 percent per 10 grains. The maximum correction applied to any of the PR-15-61 NO_x measurements was 14 percent.

In the correction factors, 75 grains of humidity has been used as the nominal value for reciprocating engines and 44 grains as the nominal value for gas turbines. These nominal humidity values were selected solely on the basis that these values are consistently used in the literature for reciprocating engines and gas turbines, respectively, and are apparently generally accepted. Since in natural gas transmission, piston engines and gas turbines are often in use at the same compressor station, it would appear that a single nominal humidity value should apply to both. As with the other atmospheric conditions, however, the overall national average humidity applicable to natural gas compression is not known.

c. Ambient Temperature Correction - Limited information was found to indicate that ambient temperature may have an effect on NO_x emissions. Unfortunately, however, insufficient data is available to merit the assumption of a correction factor. Available relationships of NO_x versus air temperature for reciprocating engines are shown in Figure 2. The GMW-6 and GMWA-6, non-turbocharged blower-scavenged two-stroke engines, represent tests in which the air temperature was varied. The PR-15-61 data points are from different engines which were tested at different ambient air temperatures. Not shown on the figure is a determination with a IR-KVSR engine in which the intake manifold temperature was varied. Assuming manifold temperature is about 30°F higher than air temperature, the slope of the results with the KVSR was a little less than the slopes for the engines shown.

In these engines, the fuel specific NO_x emissions appear to change by approximately 10 percent per 10°F change in ambient temperature. In addition to the need for establishing the relationship of the effect of temperature on emissions, it is equally important to establish a nominal temperature to correct to which is representative of the overall average temperature over which the engines operate.

In a letter from the American Society of Mechanical Engineers (ASME) to EPA dated May 1, 1973[16], the following formula was given as indicating trends of the effects of inlet temperature on NO_x emissions for gas turbines. (It was stressed in the letter that this does not represent an analytically acceptable correction factor).

$$NO_x = NO_x \text{ measured}/\Theta^4; \qquad \Theta = \frac{\text{test temp in °F} + 460\text{°F}}{519\text{°R}}$$

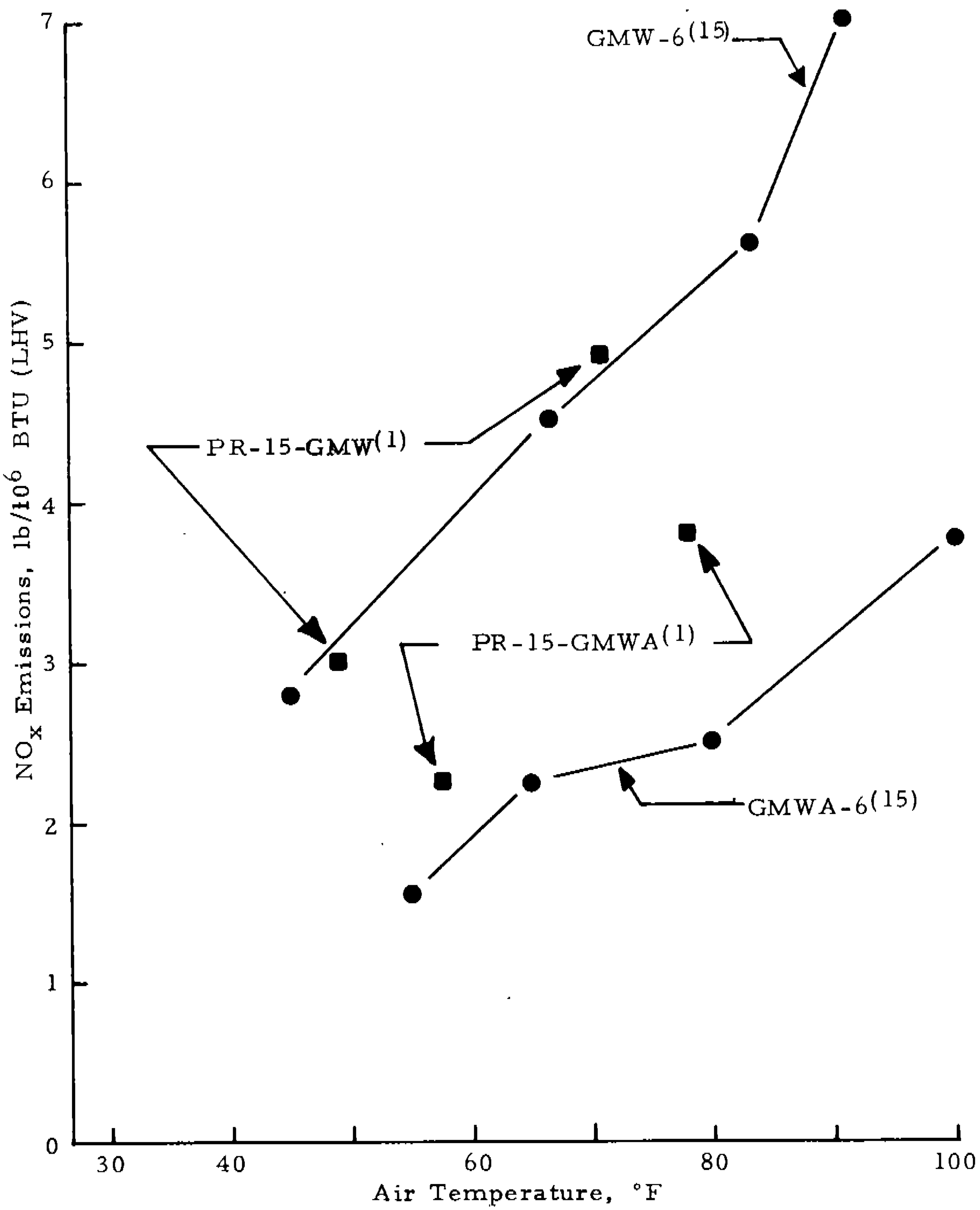


FIGURE 2. TEST RESULTS OF NO_x EMISSIONS VS INTAKE AIR TEMPERATURE FOR TWO NON-TURBOCHARGED ENGINES

Using this formula the following results would be obtained relative to the PR-15-61 emissions data for gas turbines:

(a) The maximum effect on any of the gas turbine emissions factors would be an increase of 15 percent

(b) The overall weighted average emission factor for all gas turbines would increase by 6 percent

Although these corrections are in the direction of the manufacturers stated emission values, the overall magnitude is such that the effect on the national emissions impact for natural gas compression would be very small (i. e., less than one-half of one percent).

In this evaluation, correction factors for air temperature were not used. The primary reasons for not using a temperature correction factor were: insufficient data to establish an analytically acceptable relationship and the availability of an acceptable overall average temperature for natural gas compression.

4. Summary of PR-15-61 Emissions Data

The PR-15-61 emissions data(1) are summarized in Tables 7 and 8. These data, after correction for operating load and humidity, account for the majority of the emission factors used in this project.

Some of the analyses of these data obtained in the baseline emissions survey are given in Table 9 and Figures 3 through 6. The data in Table 9 indicates that there is no direct relationship between NO_x emissions and the engine cycle configuration (2- or 4-cycle) or aspiration (natural or turbocharged). Figure 3 indicates some relationship between rated engine horsepower and the gross quantity of NO_x emitted. Figure 4 indicates that up to some point the engine efficiency (as determined by a decrease in BSFC) improves with increase in rated engine horsepower. Figures 5 and 6 illustrate that no definite relationship can be established between the rated engine horsepower and the brake and fuel specific NO_x emission rates. AGA Research Report No. 1491(17), in another study of smaller natural gas engines, reached a similar conclusion concerning the inability to find a correlation between NO_x emissions and engine size.

B. Presentation of Population and Usage Data

The collection of usage data in this project was limited to natural gas fueled compressor engines over 1000 horsepower used by AGA member companies. The almost 11 million horsepower evaluated in this project accounts for approximately 86 percent of the gas industry total for over 1000 horsepower compressor engines and approximately 75 percent of the overall total gas industry compressor horsepower.

TABLE 7. SUMMARY OF PR-15-61 GAS TURBINE EMISSIONS DATA(1)

Mfg.	Model	Horsepower Rated	Horsepower Test	Ambient Temp., °F	Humidity, Grains H_2O/Lb. Dry Air	Test Numbers	Average Emissions, g/bhp-hr NOx	CO	THC	NMHC
SO	T-1001	1,050	980	50	37	37 & 38	0.78	0.81	0.20	-
P&W	GG3C-1	10,500	12,900	44	22	16	1.54	0.50	0.12	0.002
P&W	GG3C-4	12,000	13,900	65	66	30	1.18	0.68	0.11	0.002
GE(A)	LM2500	20,000	15,200	44	22	15	1.37	0.57	0.04	0.001
GE(I)	Frame 3(S)	9,300	9,300*	74	75	5	1.0*	0.2*	-	-
GE(I)	M3912R	9,100	10,150	41	28	39	1.98	0.06	0.04	-
GE(I)	M3112R	11,100	12,000	41	28	40	1.74	0.03	0.04	-

SO - Solar
P&W - Pratt & Whitney
GE - General Electric
(A) - Aircraft type gas generator
(I) - Industrial type gas generator
(S) - Simple cycle

*Assumed value for horsepower

TABLE 8. SUMMARY OF PR-15-61 RECIPROCATING ENGINE EMISSIONS DATA[1]

Mfg.	Model	Test Numbers	Horsepower Rated HP@RPM	Horsepower Test HP@RPM	Stroke-Aspiration	Ambient Temp., °F	Humidity Grains H_2O/Lb. Dry Air	Average Emissions, g/bhp-hr NO_x	CO	THC	NMHC
CB	GMV-10	41, 42, 43, 44	1350-300	1403-300	2-NA	72	45	28.0	0.80	3.5	0.15
CB	GMW-8	31, 32, 33	2050-250	2027-250	2-NA	49	27	12.2	0.53	5.6	0.22
CB	GMW-8	45, 46	2000-250	2160-250	2-NA	71	74	18.5	0.31	4.9	0.20
CB	GMWA-6	25, 26, 27	1500-250	1544-250	2-NA	74	78	13.8	0.53	6.3	0.14
CB	GMWA-8	34, 35, 36	2000-250	2082-250	2-NA	57	34	9.0	0.48	3.6	0.14
CB	GMWC-6	28	2000-250	2090-250	2-TC	56	42	11.0	0.92	5.4	0.29
CB	GMWC-10	48, 49	3400-250	3364-250	2-TC	67	76	23.6	0.75	5.5	0.19
CB	LSV-16	9, 10, 11	4400-327	4418-332	2-TC	46	29	11.5	1.31	6.2	0.27
CB	LSVA-16	6, 7	4400-327	4450-324	2-TC	60	63	8.9	4.11	1.4	0.04
CB	10V-250	51	3400-250	3320-250	2-TC	63	43	12.3	0.53	4.1	0.71
CB	14V-250	29	4800-250	4800-250	2-TC	61	29	18.5	0.90	4.7	0.30
CB	16V-250	47	5500-250	5520-250	2-TC	69	93	17.8	1.48	3.9	0.14
CL	BA-8	55	1600-300	1590-300	2-NA	73	43	9.6	0.97	4.1	0.25
CL	BA-8	53	1760-300	1758-300	2-NA	74	31	12.3	2.90	7.6	1.38
CL	HBA-8T	17, 18, 19	2050-300	2030-300	2-TC	31	20	5.5	2.23	8.3	0.23
CL	TCV-12	23	4000-300	3937-300	2-TC	36	22	8.0	2.83	5.5	0.35
CL	TCV-16	52	5500-300	5679-300	2-TC	70	52	6.5	1.52	3.8	0.61
CL	TCVC-16	4, 50	8000-300	8042-330	2-TC	75	88	10.2	3.58	5.0	0.78
CL	TLA-6	12, 13, 14	2000-300	2000-300	2-TC	58	66	8.8	2.84	4.3	0.10
CL	TLA-6	20, 21, 22	2100-300	2082-300	2-TC	33	21	10.0	2.20	4.3	0.35
CL	TLA-8	54	2700-300	2736-000	2-TC	82	22	9.9	2.18	7.6	0.34
IR	KVG-8	57, 58	800-330	790-330	4-NA	78	56	14.0	0.62	1.3	0.01
IR	616-KVR	63, 64	5500-350	5575-350	4-TC	75	42	10.9	0.90	2.2	0.06
IR	412-KVS	3, 59, 60, 61	2000-330	2032-325	4-TC	69	42	16.6	0.68	2.8	0.08
IR	616-KVT	62	4000-350	3930-330	4-TC	64	32	8.1	1.04	2.8	0.07
WO	26x36*										
WO	UTC-10*										
WO	SUTC-8*										

CB - Cooper Bessemer
CL - Dresser Clark
IR - Ingersoll Rand
WO - Worthington
*All data on Worthington engines is of questionable validity (on one engine BSFC was less than half of normal - on another CO was more than five times normal)

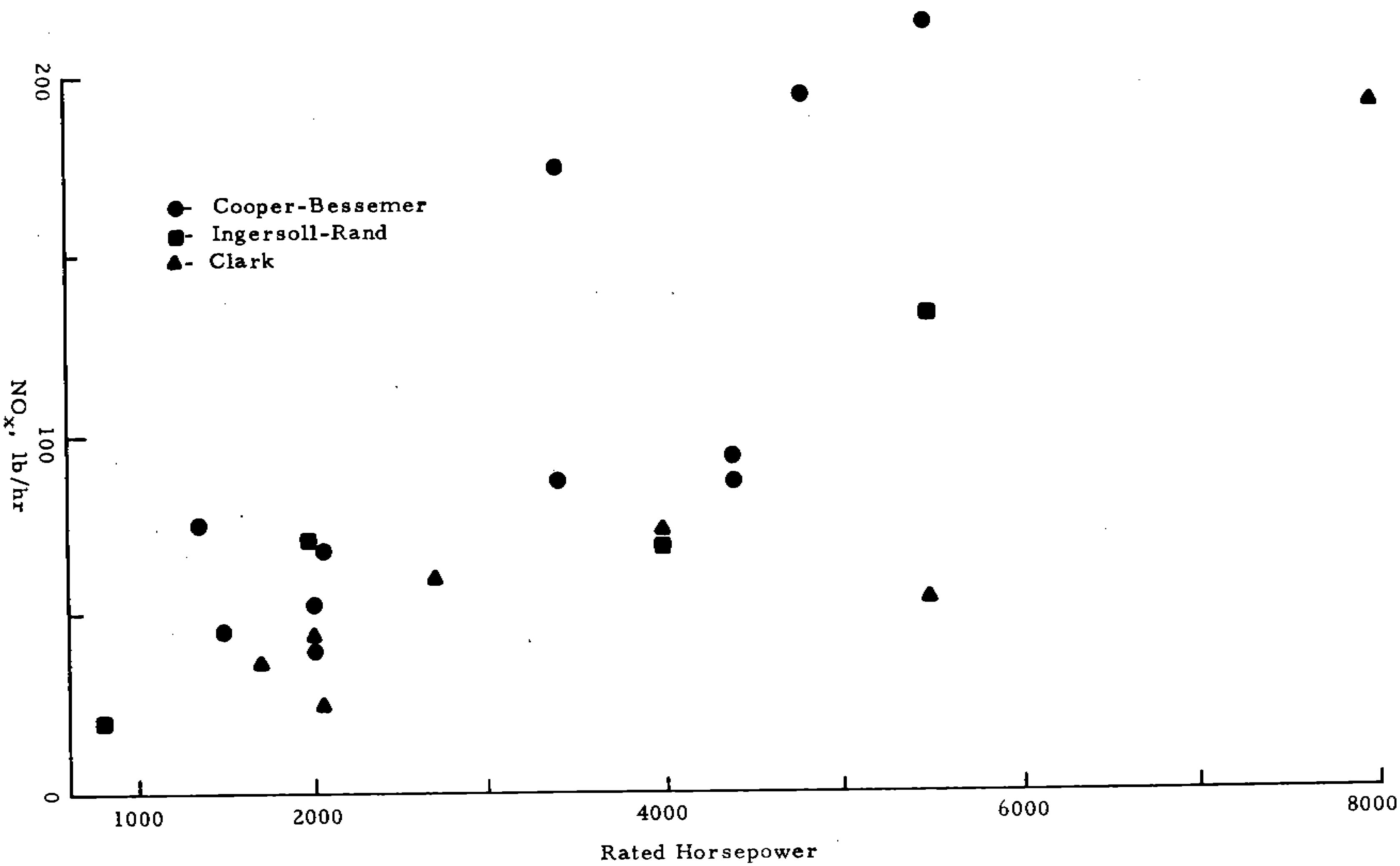


FIGURE 3. RELATIONSHIP OF NO_x EMISSIONS AND RATED HORSEPOWER
Piston Engines

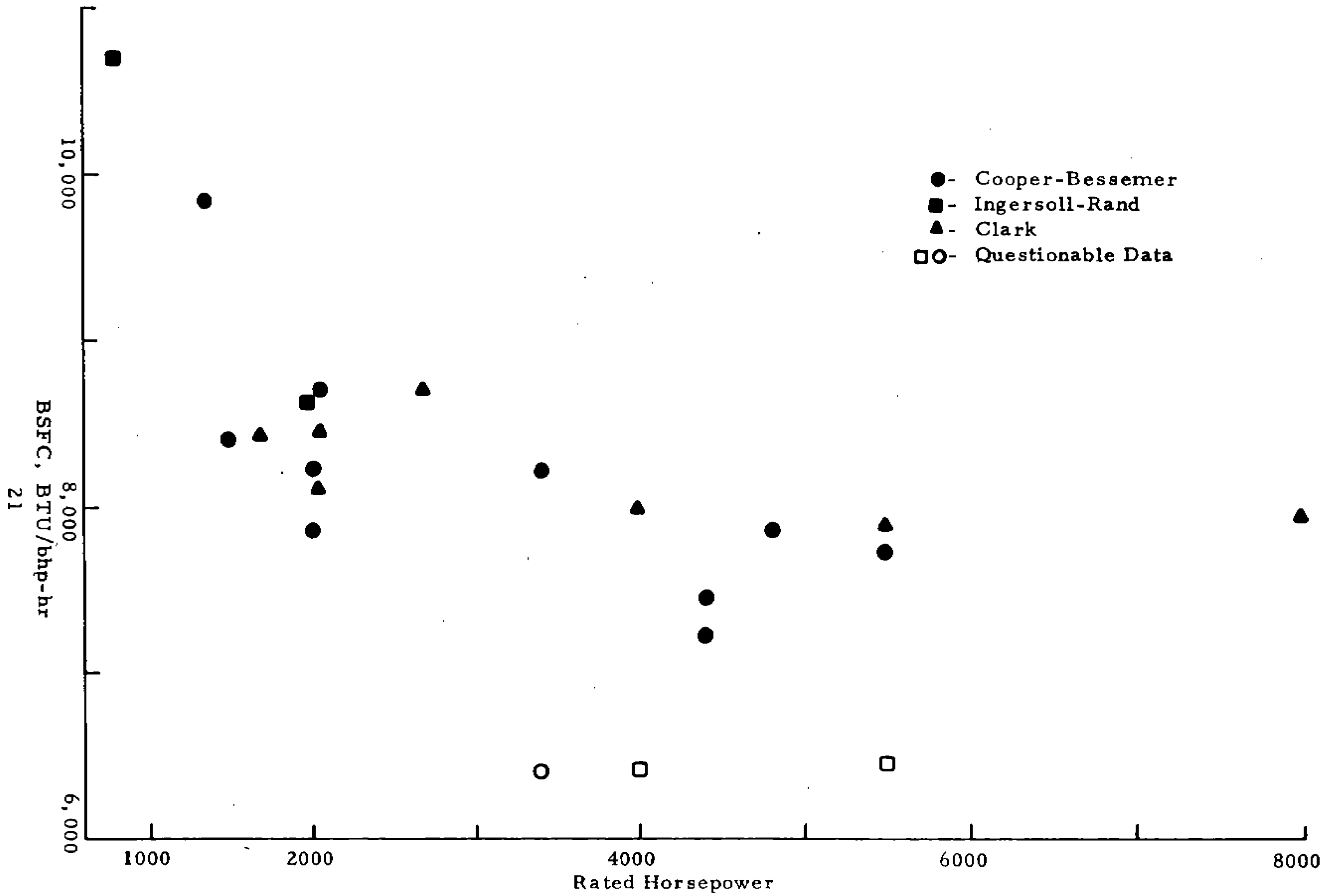


FIGURE 4. RELATIONSHIP OF BSFC AND RATED HORSEPOWER
Piston Engines

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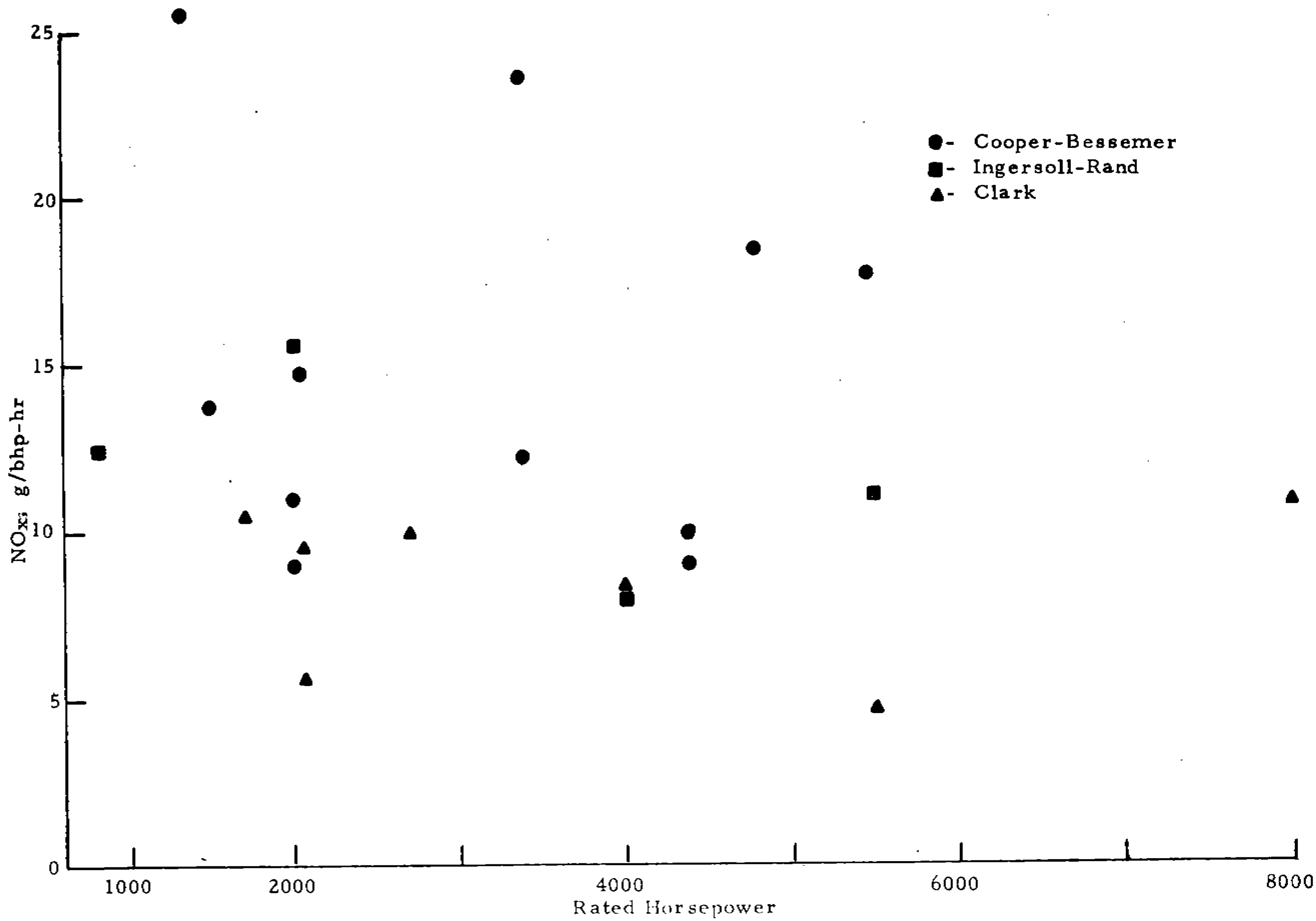


FIGURE 5. RELATIONSHIP OF NO_x MASS EMISSIONS AND RATED HORSEPOWER
Piston Engines

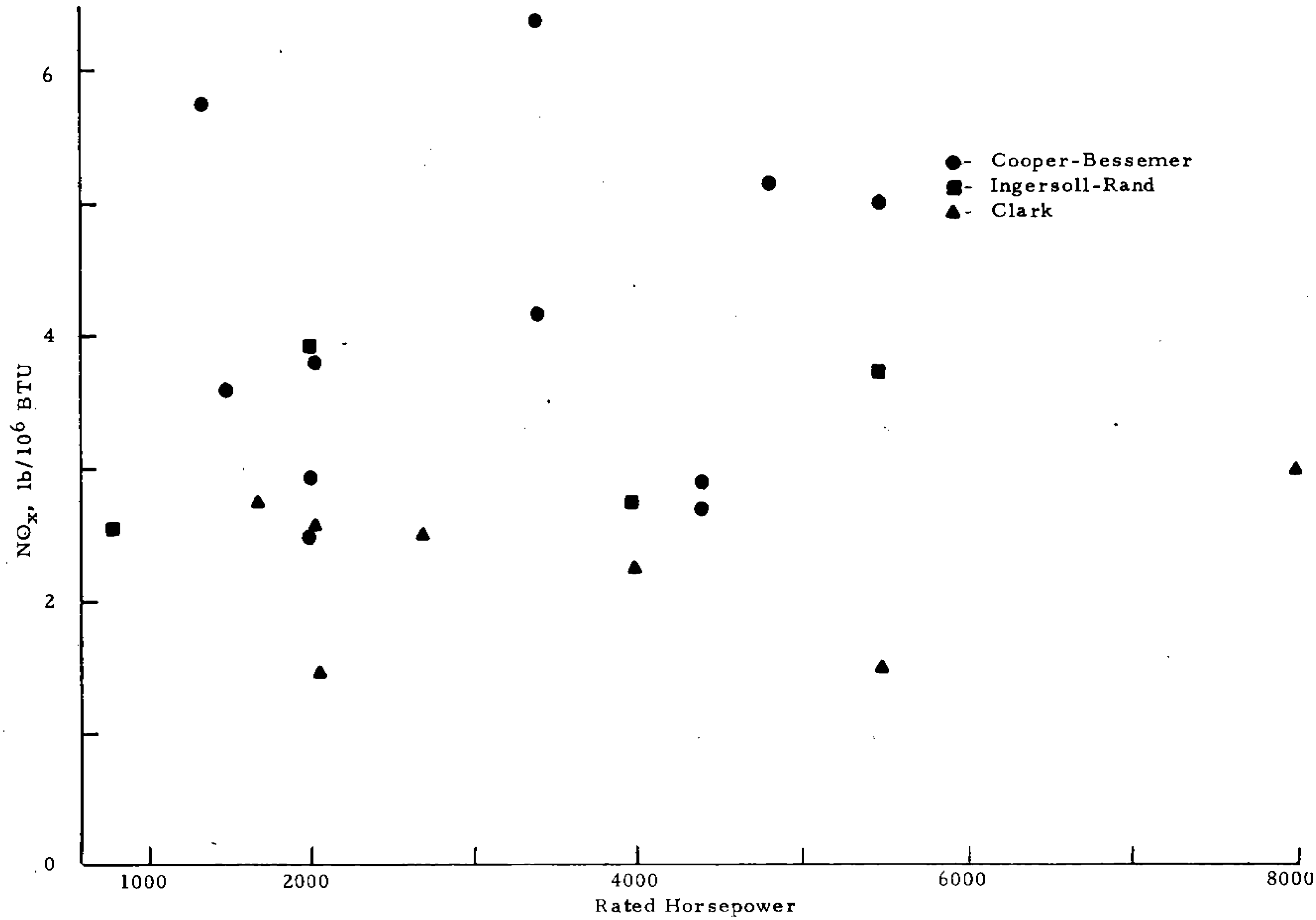


FIGURE 6. RELATIONSHIP OF NO_x FUEL SPECIFIC EMISSIONS AND RATED HORSEPOWER
Piston Engines

TABLE 9. RELATIONSHIP OF ENGINES AND NO_x EMISSIONS

Engine Description	Number of Models	NO_x, g/bhp-hr	
		Range	Average
4-cycle NA	1	14	-
4-cycle TC	3	8-17	12
2-cycle NA	4	9-28 (19)*	16 (12)*
2-cycle TC	7	6-24	11

NA - Normally aspirated
TC - Turbocharged
( )* Value obtained by omitting the single highest value

1. Companies Participating in This Project

Table 10 lists the gas companies which participated in the project. These companies include the domestic American Gas Association (AGA) members serving on the Pipeline Research Committee (PRC), along with several subsidiary companies and one AGA associate member.

Data obtained from all the companies included usage data in hours per year for engine models over 1000 horsepower. Although reported in widely divergent formats, most of the data received provided complete coverage for the operating years 1972 and 1973. In a very small percentage of the total, however, some data was omitted or erroneous and had to be estimated. Omitted or erroneous data, which could not be directly determined from other data that was provided, is estimated to be less than one percent of the total data included in this study.

In addition, sufficient operating load data was received to enable a good estimation of the overall average operating load factor. (Load factor is defined here as the ratio of the operating Hp to the rated Hp). Five of the gas companies provided load factor data and seven made general statements regarding load factor. The factors and comments are summarized as follows:

Number of Companies	Transmission Horsepower	Average Load Factor, %			Stated L. F., %
		Recip.	Turbine	Overall	
5*	4,450,000	96	96*	96	-
4	1,150,000	-	-	-	100 ± 10
3	1,050,000	-	-	-	100

*Four company average for the turbine

TABLE 10. NATURAL GAS COMPANIES WHICH PARTICIPATED IN THIS PROJECT

AGA-PRC Company Name	1972 Installed Horsepower		
	Transmission	Other	Total
Algonquin Gas Transmission Co.	30,900	0	30,900
Cities Service Gas Co.	223,110	75,980	299,090
Colorado Interstate Corporation	116,630	72,046	188,676
Columbia Gas Transmission Co.	346,251	105,967	452,218
Columbia Gulf Transmission Co.	472,820	0	472,820
Consolidated Gas Supply Corp.	79,440	205,940	285,380
Consumers Power Company	45,860**	56,942	102,802*
El Paso Natural Gas Co.	941,480	573,368	1,514,848
Michigan Wisconsin Pipe Line Co.	668,860	117,305	786,165
Natural Gas Pipeline Co. of America	935,200	117,695	1,052,895
Northern Natural Gas Co.	897,821	74,622	972,443
Oklahoma Natural Gas Co.	0	12,500	12,500
Panhandle Eastern Pipe Line Co.	494,576	98,338	592,914
Southern California Gas Co.	120,220**	22,040	142,240*
Southern Natural Gas Co.	351,160	38,087	389,247
Tennessee Gas Pipeline Co.	1,190,525	16,200	1,206,725
Texas Eastern Transmission Corp.	1,176,110	84,998	1,261,108
Texas Gas Transmission Corp.	459,010	13,807	472,817
Transcontinental Gas PipeLine Corp.	951,185	54,706	1,005,891
United Gas PipeLine Co.	189,305	39,850	229,155
Florida Gas Transmission Co.	145,140	4,275	149,415
Trunkline Gas Company	337,500	0	337,500
Great Lakes Gas Transmission Co.	332,000	23,550	355,550
Sub-total	10,505,103	1,808,216	12,313,319
Less Northwest Division of El Paso N.G. Co.			122,450
Total for Companies included in this project			12,190,869

Primary Data Source: The Oil and Gas Journal, June 11, 1973[19]

*Pipeline News Directory, October 15, 1973[20]

**Estimated from Chilton's Gas 1973 Global Directory of Gas Companies.[21]

The average individual company load factors for the reciprocating engines ranged from 91 to 100 and for the turbines from 91 to 101. A load factor of 96 percent was used in the determination of emissions impact.

2. Total Natural Gas Industry Compressor Horsepower

Two sources were approached for determination of total gas industry installed compressor horsepower. One was the American Gas Association publication, Gas Facts[18], and the other was the statistical issues of various magazines and other publications[19, 20, 21] covering the gas industry. The values given in Gas Facts were discussed with the statistical section at AGA to assure a correct understanding of the nomenclature used. Totals derived from these two different sources are given in Table 11. These totals are within one percent, which is very good agreement.

TABLE 11. TOTAL 1972 GAS INDUSTRY COMPRESSOR HORSEPOWER

AGA Gas Facts[18] - (Gas Utility Industry)	-	-	14,506,000
Other Sources			
The Oil and Gas Journal[19] (Gas Pipeline)	11,334,393	1,976,880	13,311,273
Pipeline News Directory[20] (Gas Pipeline Companies not in O & G Journal)	629,000**	433,000**	1,102,000*
Pipeline News Directory (Gas Distribution Companies)	-	-	250,000
Total Gas Industry	11,963,393	2,409,880	14,663,273

*Pipeline News Directory, October 15, 1973[20]
**Estimated from Chilton's Gas 1973 Global Directory of Gas Companies[21].

No source could be located which provided a reliable breakdown of the total into reciprocating engines, gas turbines, and other. Therefore, a composite of a number of sources was required to enable development of a satisfactory breakdown. The derivation of a breakdown of the installed natural gas compressor horsepower is as follows:

The AGA Directory of Reciprocating Gas Engines[2] listed approximately 7,815,000 horsepower (excluding Canadian companies) for over-1000 horsepower engines in 1973. The AGA Directory includes companies having as much as 95 percent of total gas utility industry horsepower. After adjusting this value about five percent to include companies not included in the Directory, we add 855,000 horsepower for old type engines in use by the older companies included in this project, but which are not included in the AGA Directory. Since the 855,000 horsepower for old type engines were all included in only a few of the older companies, it will be assumed that this value includes all of these old type engines. Therefore, the total installed horsepower for over-1000 horsepower reciprocating engines in 1973, estimated to be about 9,000,000 horsepower.

A cross-check of horsepower quantities is given in Table 12. In most cases, a combination of several sources was required to enable developing a value for direct comparison. Out of an overall total of 8,018,106 horsepower for over 1000 hp reciprocating engines determined to be available in the companies which participated in this project, 7,662,963 were included in this study.

Gas turbine sales and installation data were obtained from four gas turbine manufacturers; General Electric Industrial, General Electric Aircraft, Pratt & Whitney (now called Turbo Power & Marine Systems), and Solar. Based on these data, the total installed gas turbine horsepower for natural gas compression supplied by these companies is approximately 3,640,000. Total gas turbine horsepower, in the AGA-PRC companies, supplied by other manufacturers was determined from the operating data to be 460,000. Approximately half of this total was in one gas transmission company. If it is assumed that the gas companies not directly included in this study have a negligible amount of turbine horsepower supplied by these "other" manufacturers, the total installed gas turbine horsepower as of 1973 comes out to be 4,100,000. Another method for estimating the total installed gas turbine horsepower is to extrapolate the values determined for the AGA-PRC companies to the total gas utility horsepower. Assuming the ratio of gas turbine to total horsepower is the same in non-AGA member companies as in AGA-PRC companies, the total gas turbine horsepower is extrapolated to be approximately 3,960,000 in 1973. The results obtained by the two different methods agree quite well. For this evaluation a value of 4,000,000 total installed gas turbine horsepower will be used.

Adding the estimated total 1973 gas utility industry over-1000 horsepower reciprocating engines and the gas turbines gives approximately 13,000,000 horsepower. Subtracting this value from the AGA 1973 value of 14,858,000 for total gas utility industry compressor horsepower, leaves a little less than 2,000,000 horsepower. This remaining horsepower covers under-1000 horsepower reciprocating engines, electric motors and all others. Further breakdown of this 2 million horsepower would require a very comprehensive study or essentially outright assumptions. A total of 976,140 horsepower was reported for steam turbine plus electric compressor drives in reference 4. However, the 1971 total natural gas utility compressor horsepower in this same reference added up to 15,184,000, whereas AGA, in <u>Gas Facts</u>[18], gives a total for the gas utility industry of 14,142,000 horsepower in 1971. Even if a detailed breakdown of this horsepower were available, operating data is not available and would have

TABLE 12. RECIPROCATING ENGINE COMPRESSOR HORSEPOWER INCLUDED IN THIS PROJECT
Engines Over 1000 Rated Horsepower - 1973

		Horsepower
Reciprocating Engine Horsepower Included in This Project (from Appendix B)		7,662,963
Total Piston Engine Horsepower in the Gas Companies which Participated in this Project		8,018,106
Directory of Reciprocating Gas Engines(2)	7,815,046*	
Less companies not members of AGA	- 529,150	
Less Northwest Pipeline Company	- 122,540	
Plus old type engines in this project which are not in Directory	+ 854,750	

*Excludes Canadian Pipelines

to be assumed.

Therefore, in this project, the assumption will be used that these under 2 million horsepower produce emissions proportional to the overall emissions rate per installed horsepower for the AGA-PRC companies included in this study. This assumption basically assumes that approximately two-thirds of this horsepower is under-1000 horsepower piston engines and the remainder either electric motors or steam turbines. To examine the potential effect of these 2 million horsepower the relative emission rates at estimated extremes will be determined. It is estimated that the under 1000 horsepower piston engines are greater than 50 percent but less than 80 percent of the almost 2 million horsepower. Based on the data in reference 17, the average emission factor for under-1000 hp piston engines is assumed to not differ significantly from the average factor for over-1000 hp piston engines. Following is the relative effect of total NO_x emissions of these 2 plus million horsepower.

% of 2,000,000 hp that are under 1000-hp piston engines	Relative total Gas Utility Industry Compressor NO_x Emissions
50	3% lower than *
67	*
80	2% higher than *

*The nationwide NO_x emissions impact values as determined in this project for the total gas utility industry installed compressor horsepower

As indicated, the relative error associated with the breakdown of the 2,000,000 horsepower is only a few percent at the most.

C. Development of Emission Factors

The decision was made to use individual emission factors for each engine family. In addition to increasing the accuracy of the emissions impact evaluation (over using a single factor for piston engines and another for gas turbines), this also enables easy updating of the impact values as additional emissions data becomes available. The gas turbine breakdown was on an individual model basis since the total number of models was small. The piston engines were grouped into families of similar engines with the review and concurrence of the piston engine manufacturers.

The rationale used in the selection of emission factors was as follows:

(1) If the data from the manufacturer agreed with the PR-15-61

values (with correction factors applied) or if no manufacturer's data was available, the PR-15-61 adjusted value was used.

(2) If the data from the manufacturer disagreed with the PR-15-61 adjusted value, an attempt was made to resolve the difference. Wherever the difference could not be resolved, the PR-15-61 data was used.

(3) If the engine model was not measured in PR-15-61, manufacturer's data were generally used when available. Where the applicable manufacturer's data were not available, the emissions were estimated from similar engine models or assigned a nominal average value.

The determination of an emission factor generally involved the following:

(1) Selective averaging of the PR-15-61 data to establish the emissions values at an operating condition near the rated horsepower

(2) Application of the applicable load and humidity correction factors to adjust values to the rated operating load and the selected humidity

(3) Comparison of these emission values with available emission values from other sources

(4) Attempts to resolve any differences that occurred

(5) Selection of the rated load emission factor for use in determination of Emissions Impact

The actual emission factors used by the computer in the determination of the emissions impact are given in the computer printouts in Appendix A.

D. Estimation of National Emissions Impact

1. Method Used

The emissions impact of AGA member companies was calculated using a computer. The operating data inputs included: location, engine quantity by model at each location, engine rated horsepower and engine annual hours of operation. A brief description of the computer program for the determination of emissions impact is given in Table 13 and the complete program is enclosed as Appendix C. A number of data checks were incorporated in the program to insure against gross errors.

TABLE 13. BRIEF SUMMARY OF COMPUTER PROGRAM

1. Read Rated Load Brake Specific Emission Factors

2. Correct to 96% load factor and store

3. Run data checks:

   a. Individual model horsepower is under 30,000
   b. Operating hours is less than 8784 times number of engines
   c. Engines per model per site are less than ten (done visually from computer printout of data)
   d. Various non-numerical checks

4. Installed horsepower equals Model Hp times number of engines of that model

5. HP-HR equals 0.96 times model Hp times operating hours

6. Emissions equals HP-HR times stored brake specific emission factor

7. Sum up by engine type by state

8. Determine 48 state totals

The overall total gas industry national emissions impact was estimated using direct extrapolation of the values obtained for the AGA member companies to the total gas industry compressor horsepower.

2. Results

The direct results of this study are given in the computer printouts in Tables B-1 through B-6 in Appendix B. These results are for gas turbines and reciprocating engines, of 1000 horsepower and over, used for compression of natural gas by AGA-PRC member companies. Included in these appendix tables are statewide and nationwide emissions for gas turbines, reciprocating engines, and gas turbines plus reciprocating engines for 1972 and 1973. A summary presentation of these data is given in Table 14.

The data in Table 14 indicate that although there was a small increase in installed compressor horsepower in 1973, there were slightly less brake horsepower hours of operation and therefore less emissions produced. Gas turbines, which accounted for 30 percent of the total installed horsepower (in these direct results) in both 1972 and 1973, account for 29 percent of the bhp-hrs operated in 1972 and 28 percent in 1973.

Based on the data in Appendix Table B-3, in 1973, eight states accounted for 60 percent of the NO_x produced by AGA-PRC member companies. These eight states are as follows:

State	NO_x Emissions, tons/year	State	NO_x Emissions, tons/year
Texas	71,631	Kentucky	31,160
Kansas	70,057	Tennessee	27,537
Louisiana	52,010	New Mexico	26,587
Mississippi	50,915	Pennsylvania	20,177

A map of major natural gas pipelines is shown in Figure 7. This map is published by the Federal Power Commission and is available from the U. S. Government Printing Office as stock number 1500-00258. This map illustrates that those states having more mileage of gas transmission pipelines produce more NO_x emissions from compressors of 1000 horsepower and greater. In general, the gas transmission pipelines are those crossing two or more state lines.

Table 15 gives the total emissions for 1973 as determined in this project, the results extrapolated to the gas industry, and the estimated overall total nationwide emissions for 1971. The Fourth Annual Report of the Council on Environmental Quality, September 1973 (Reference 22), was used as the basis to which the gas industry emission estimates were compared. This report, for 1971 calendar year, was the latest and most reliable set of national emission estimates available at the time of the study. The gas

TABLE 14. SUMMARY OF EMISSIONS PRODUCED BY AGA-PRC MEMBER COMPANIES

Natural Gas Compressors Over 1000 Hp

Engine Type	Installed Horsepower	Bhp-Hours Operated	Emissions, Tons/Year NO_x	CO	HC
1972 Calendar Year					
Reciprocating	7,545,000	47,184,000,000	577,000	69,000	224,000
Turbine	3,297,000	19,434,000,000	30,100	7,700	1,500
Total	10,842,000	66,618,000,000	607,000	77,000	226,000
1973 Calendar Year					
Reciprocating	7,663,000	45,306,000,000	553,000	67,000	215,000
Turbine	3,332,000	17,899,000,000	27,800	6,900	1,300
Total	10,995,000	63,205,000,000	581,000	74,000	216,000

TABLE 15. EMISSIONS SUMMARY - NATURAL GAS COMPRESSOR HORSEPOWER

Emission	1973 Calendar Year: 10,994,871 Hp in this Project*	Gas Industry**	1971 Total Nationwide(22)	1973 Gas Industry Emissions as % of 1971 Total
NO_x	581,000	784,000	22,000,000	3.6
CO	74,000	100,000	100,000,000	0.1
Total HC	217,000	293,000	26,600,000	1.1
Non-Methane HC	10,800	14,600	-	-

*From computer printouts in Appendix B

**Extrapolated, on the basis of installed horsepower, from the value in the computer printout. (Emissions determined times 14,858,000 divided by 10,994,871)

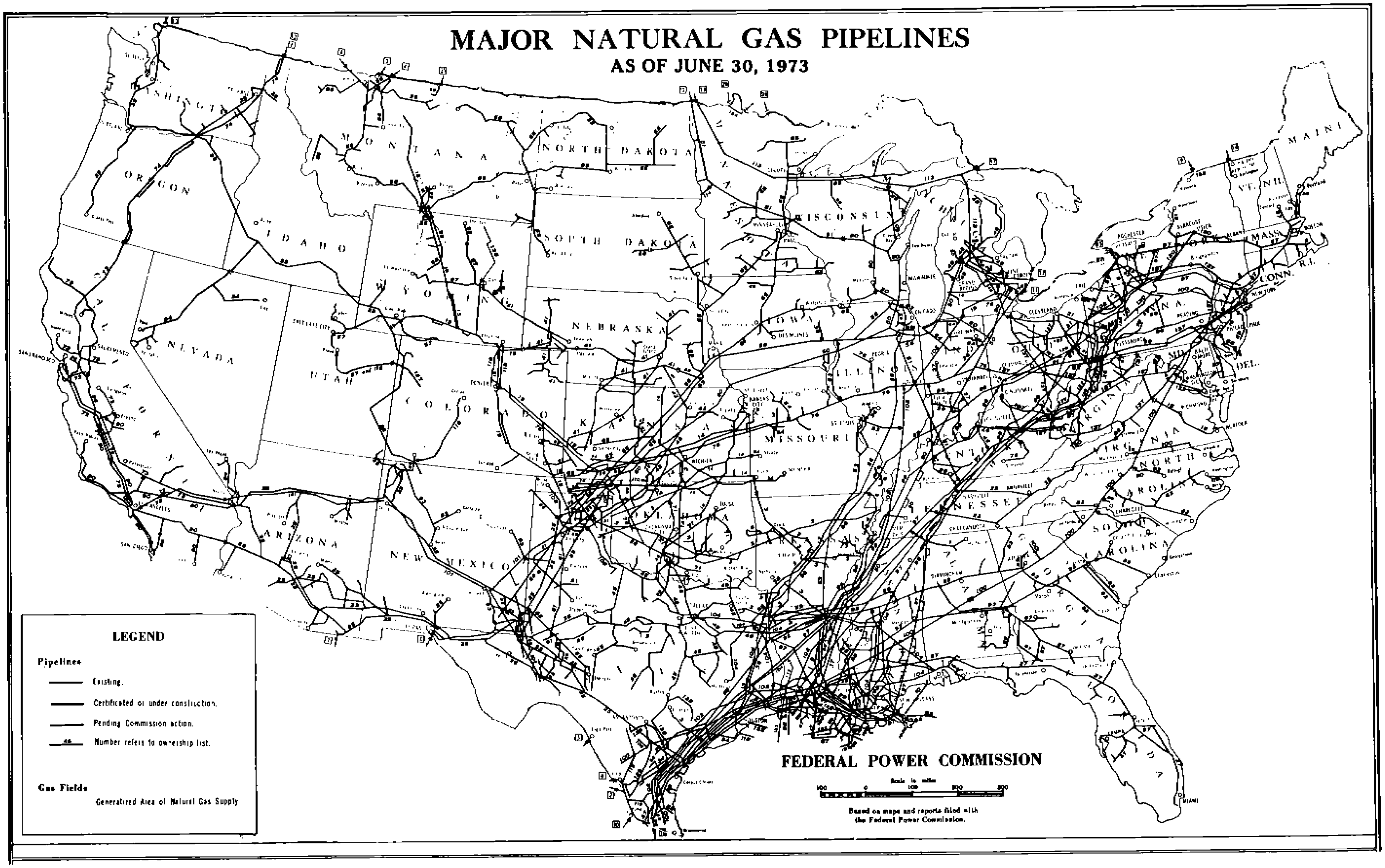


FIGURE 7. MAJOR NATURAL GAS PIPELINES

industry emissions estimates may be compared to future national inventory data as it becomes available. As shown in the table, natural gas compressor horsepower in 1973 were estimated to produce about 3.6 percent of the NO_x, 0.1 percent of the CO and 1.1 percent of the total HC.

Additional comparison breakdowns of the national emissions impact results are given in Tables 16 through 19. These tables compare the results of this project with the 1971 EPA Nationwide Air Pollutant Inventory Data and with the results of another emissions impact evaluation which used a different approach. With respect to HC and NO_x emissions, the results of this and the other study are in very good agreement.

TABLE 16. COMPARISON OF NATIONAL ESTIMATES OF EMISSIONS FROM NATURAL GAS COMPRESSION WITH EPA NATIONWIDE AIR POLLUTANT INVENTORY DATA

	1971 EPA Inventory Data, in million tons per year[a]		AGA-PRC over 1000 HP[b], in % of 1971 EPA Inventory Data		Gas Utility Ind.,[c]** as percent of 1971 EPA Inventory Data	
Emission	Total	Stationary	Total	Stationary	Total	Stationary
HC*	26.6	11.9	0.8	1.8	1.1	2.5
CO	100.2	22.7	0.07	.33	0.1	.44
NO_x	22.0	10.8	2.6	5.4	3.6	7.3

(a) Environmental Quality - the fourth Annual Report of the Council on Environmental Quality, pg. 266, September 1973[22].
(b) Computer Printout in this project (Appendix B)
(c) Extrapolation of project results to total gas utility industry compressor horsepower

*Total hydrocarbons
**As used in Gas Facts[18] - published by the American Gas Association

Note: Stationary EPA Inventory Data includes all sources other than transportation.

TABLE 17. COMPARISON OF NATIONAL ESTIMATES OF HYDROCARBON EMISSIONS FROM NATURAL GAS COMPRESSION WITH EPA NATIONWIDE AIR POLLUTANT INVENTORY DATA

Source	Year	in millions Hp	in millions Hp-hr	HC***, mil. tons/year	Percent of 1971 EPA Inventory Data Stat.	Percent of 1971 EPA Inventory Data Total
Stationary Sources[a]	1971	--	--------	11.9	----	44.7
Total Nationwide[a]	1971	--	--------	26.6	----	---
AGA-PRC over 1000 hp[b]	1973	11	63,205	0.22	1.8	0.8
Gas Utility Industry[c]	1973	15	85,000	0.3	2.5	1.1
Shell Report[d]	1971	--	87,610*	0.27*	2.3	1.0
Gas Recip. - AGA-PRC[b]	1973	8	45,306	0.22	1.8	0.8
Gas Recip. - Gas Ind.[c]	1973	10	61,000	0.29+	2.5	1.1
Gas Recip. - Shell Rep.[d]	1971	--	66,350**	0.27**	2.3	1.0
Turbine - AGA-PRC[b]	1973	3	17,900	0.001	0	0
Turbine - Gas Ind.[c]	1973	4	21,000	0.002	0	0
Turbine - Shell Rep.[d]	1971	--	21,260**	--------	----	---

(a) Environmental Quality - the fourth Annual Report of the Council on Environmental Quality, pg. 266, September 1973.[22]

(b) Computer printout in this project (Appendix B).

(c) Extrapolation of project results to total gas utility industry compressor horsepower.

(d) Shell Development Company, Stationary Internal Combustion Engines in the United States, page 36, April 1973.[4]

* Total recip. gas engines and gas turbines in oil and gas pipelines.

** Total for oil and gas pipelines.

*** Approximately 5 percent of the total hydrocarbon value shown is non-methane[1].

Note: Stationary EPA Inventory Data includes all sources other than transportation.

TABLE 18. COMPARISON OF NATIONAL ESTIMATES OF CARBON MONOXIDE EMISSIONS FROM NATURAL GAS COMPRESSION WITH EPA NATIONWIDE AIR POLLUTANT INVENTORY DATA

Source	Year	in millions Hp	in millions Hp-hr	CO, mil. tons/year	Percent of 1971 EPA Inventory Data Stat.	Percent of 1971 EPA Inventory Data Total
Stationary Sources[a]	1971	--	--------	22.7	----	22.7
Total Nationwide[a]	1971	--	--------	100.2	----	-----
AGA-PRC over 1000 hp[b]	1973	11	63,205	0.074	.33	0.07
Gas Utility Industry[c]	1973	15	85,000	0.10	.44	0.10
Shell Report[d]	1971	--	87,610*	0.27	1.19	0.27
Gas Recip. - AGA-PRC[b]	1973	8	45,306	0.067	.30	0.07
Gas Recip. - Gas Ind.[c]	1973	10	61,000	0.09	.40	0.09
Gas Recip. - Shell Rep.[d]	1971	--	66,350**	0.270**	1.19	0.27
Turbine - AGA-PRC[b]	1973	3	17,900	0.007	.03	0.007
Turbine - Gas Ind.[c]	1973	4	21,000	0.01	.04	0.01
Turbine - Shell Rep.[d]	1971	--	21,260**	---------	----	-----

(a) Environmental Quality - the fourth Annual Report of the Council on Environmental Quality, pg. 266, September 1973.[22]

(b) Computer printout in this project (Appendix B).

(c) Projection of project results to total gas utility industry compressor horsepower.

(d) Shell Development Company, Stationary Internal Combustion Engines in the United States, page 36, April 1973.[4]

* Total recip. gas engines and gas turbines in oil and gas pipelines.

** Total for oil and gas pipelines.

Note: Stationary EPA Inventory Data includes all sources other than transportation.

TABLE 19. COMPARISON OF NATIONAL ESTIMATES OF OXIDES OF NITROGEN EMISSIONS FROM NATURAL GAS COMPRESSION WITH EPA NATIONWIDE AIR POLLUTANT INVENTORY DATA

Source	Year	Hp	in millions Hp-hr	NO_x, mil. tons/year	Percent of 1971 EPA Inventory Data Stat.	Percent of 1971 EPA Inventory Data Total
Stationary Sources[a]	1971	--	-------	10.8	----	49
Total Nationwide[a]	1971	--	-------	22.0	----	-----
AGA-PRC over 1000 hp[b]	1973	11	63,205	0.58	5.4	2.6
Gas Utility Industry[c]	1973	15	85,000	0.78	7.3	3.6
Gas Utility Industry	1973	14	82,000***	0.77***	----	----
Shell Report	1971	--	87,610*	0.89*	8.2	4.0
Gas Recip.-AGA-PRC[b]	1973	8	45,306	0.55	5.1	2.5
Gas Recip.-Gas Ind.[c]	1973	10	61,000	0.74	6.9	3.4
Gas Recip.-Shell Rep.[d]	1971	--	66,350**	0.85**	7.9	3.9
Turbine-AGA-PRC[b]	1973	3	17,900	0.028	.26	0.13
Turbine-Gas Ind.[c]	1973	4	21,000	0.034	.31	0.15
Turbine-Shell Rep.[d]	1971	--	21,260**	0.040**	.37	0.18

(a) Environmental Quality - the fourth Annual Report of the Council on Environmental Quality, pg. 266, September 1973.[22]

(b) Computer printout in this project (Appendix B)

(c) Extrapolation of project results to total gas utility industry compressor horsepower.

(d) Shell Development Company, Stationary Internal Combustion Engines in the United States, page 36, April 1973.[4]

* Includes only the total recip. gas engines and gas turbines in oil and gas pipelines.

** Total for oil and gas pipelines.

*** Gas recip. and turbine horsepower only.

Note: Stationary EPA Inventory Data includes all sources other than transportation.

3. Discussion of the Results

On a statewide basis, the AGA member companies are representative of the overall industry in the Eastern states but not in the Western states. The following states are not well represented by the data in this study: California, Idaho, Montana, Nevada, North Dakota, Oregon, Utah, and Washington. Therefore, the statewide emission values in the Western states must be adjusted for total statewide horsepower prior to usage of the data on a statewide basis.

The estimate of the overall nationwide emission impact was made by extrapolating the total horsepower included in this project to the overall total gas industry horsepower. The extrapolation as made here assumes that the under-1000 horsepower engines plus the steam and electric units produce emissions at an average rate the same as the combined weighted rate of the over-1000 horsepower engines and gas turbines. With these assumptions, the overall nationwide emissions of NO_x by the gas industry in 1973 comes out to be 784,000 tons (14,858,000 divided by 10,994,871 multiplied by 579,743.) This value represents 3.6 percent of the overall estimated 1971 nationwide NO_x emissions of 22 million tons.

The carbon monoxide (CO) emissions in 1973 were 73,644 tons, which has been extrapolated to 100,000 tons for the overall gas industry. This value represents about one-tenth of one percent of the overall nationwide estimate of 100 million tons. The 216,696 tons of HC, when extrapolated to 293,000 tons for the overall gas industry, represents one and one-tenth percent of the overall nationwide estimate of 26.6 million tons. However, methane is generally not considered to be an emission of concern and only about 5 percent of the HC emitted from natural gas engines is non-methane. The non-methane HC emitted by the gas transmission industry in 1973 was an estimated 14,300 tons which represents only 0.05 percent of the overall nationwide estimate for total HC. It seems reasonable to conclude that on a nationwide basis the CO and HC emissions produced by the gas industry for gas compression are not very significant.

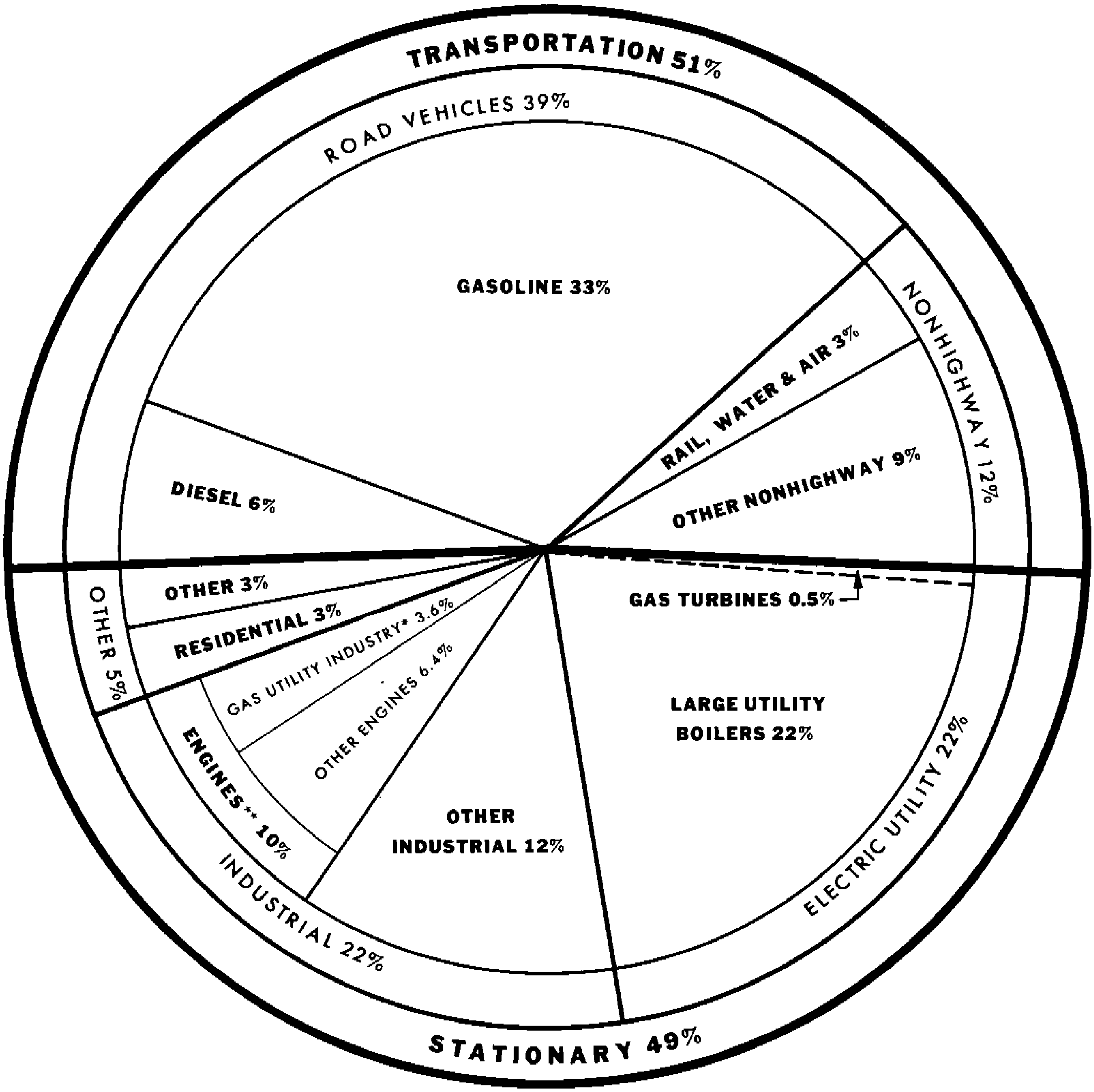
As discussed previously, the majority of the major gas turbine manufacturers report gas turbine NO_x emissions to be about fifty percent higher than the values determined in AGA project PR-15-61. To see what effect this would have on nationwide gas industry NO_x emissions, the gas turbine NO_x emissions will be multiplied by a factor of 1.5. This would result in nationwide gas industry NO_x emissions of 804,000 tons (27,823 times 1.5 plus 553,353 and adjusted to total gas industry). This value is only about 2.5 percent higher than the 784,000 tons of NO_x emissions as estimated in this project. Overall, therefore, gas turbines contributed only about five to seven and one-half percent of the total gas utility industry NO_x emissions from natural gas compressor engines in 1973.

In summary, the emissions of CO and non-methane HC resulting from compression of natural gas appear to be relatively insignificant on a nationwide basis. These emissions account for less than 0.1 percent of the overall nationwide CO and total HC emissions, respectively. NO_x emissions resulting from compression of natural gas are estimated to be 784,000 tons in 1973, which is approximately 3.6 percent of the estimated overall nationwide total NO_x emissions.

Several considerations should enter any evaluation of the significance of NO_x emissions and two of these will be mentioned. First, the map published by the FPC which shows Major Natural Gas Pipelines illustrates that generally the pipelines are not located in densely populated sections of the country. Second, the compressor stations are generally not located within urban areas. Therefore, the significance of the NO_x emissions from gas compression is largely a localized problem. For determination of whether these NO_x emissions are a localized problem, further study would be required.

In a 1969 report(23), gas engines used in pipelines were estimated to emit 1.6 million tons of NO_x while consuming 436 billion standard cubic feet of natural gas. In the PR-15-61 project, reciprocating gas engines, in the gas utility industry, produced about 0.75 million tons of NO_x while consuming an estimated 500 billion standard cubic feet of natural gas. The reason for this over 50 percent difference in NO_x emission between the 1969 study and the PR-15-61 study is that the AP-67(24) NO_x emission factor of 7,300 $lb/10^6\ ft^3$ was used in the 1969 study. This value for gas engines is approximately equivalent to 26 g/bhp-hr as compared with an average value of approximately 11 g/bhp-hr as can be derived from the computer printouts from Appendix B of this report. The average value reported in AP-67 is more than two times the average value of the engines measured in this project. Therefore, it is understandable that the results would have been significantly higher than the results determined in this evaluation.

In conclusion of this impact study, it is important that the gas utility industry emissions of NO_x be put into perspective relative to other sources. Therefore, using a combination of several sources, the breakdown of 1971 nationwide NO_x emissions was developed and this data is presented in Figure 8. The majority of the values shown were directly obtained or estimated from references 22 and 25. The gas utility industry values were determined in this study and the total for engines and gas turbines was determined from reference 4. The NO_x emissions for electric utility gas turbines were estimated from a combination of references 4 and 5. Most of the values labeled are the remaining values after subtraction (i.e., Other I.C. Engines equals Engines and Gas Turbines minus the Gas Utility Industry). Since there is no authorized source, or sources, for all the values given in the figure, the values are subject to some interpretation.



* - Gas Utility Industry as defined in Gas Facts[18]. The 1973 emission value used is estimated to represent the 1971 emissions.

** - Reciprocating Engines 9.6% and Gas Turbines 0.4%.

FIGURE 8. NO_x EMISSIONS FROM VARIOUS SOURCES 1971 National Estimates[4, 22, 24, 25]

Figure 8, in brief, illustrates the following relative to estimated nationwide NO_x emissions. The total emissions (based on the methods of calculation used) were about equally divided between Transportation and Stationary sources. Gasoline fueled road vehicles were the largest single segment. The segment identified as industrial accounted for about 22 percent of the total NO_x; slightly under half (10 percent) of which was estimated to be produced by stationary reciprocating engines and gas turbines. Of the 10 percent for stationary reciprocating engines and gas turbines, a little over one-third (3.6 percent) was produced by the gas utility industry (as defined in Gas Facts(18)). In 1971, gas turbines produced a relatively insignificant amount of NO_x emission; the estimated total for all gas turbines being less than 1 percent of the total NO_x emissions. Gas turbines in the gas utility industry produced an estimated 0.2 percent of the 1971 nationwide NO_x emissions.

III. EMISSION CONTROL TECHNOLOGY ASSESSMENT

This section will discuss the current technical state-of-the-art for controlling NO_x emissions from reciprocating engine and gas turbine powered natural gas compressors. A significant portion of the applicable control technology evaluations were conducted and reported in 1971 and 1972. This especially applies to the reciprocating gas engines. A fairly significant amount of reported control technology evaluations are available for gas turbines. For reciprocating gas engines, the reported control technology evaluations are more limited. The control systems developed for gasoline automobiles generally do not appear to be directly applicable to the natural gas engines used in gas compression applications. The operating cycles, the overall air/fuel ratio, the usage factors, etc., are very different.

A. Gas Turbines

It was found that a considerable amount of emission control technology work has been conducted with the large gas turbines used by the electric power industry. Although the majority of these evaluations have been conducted using liquid fuel, it appears that the relative reductions in NO_x emissions are generally applicable to the majority of the gas turbines used for driving natural gas compressors. A significant number of reports are available in the literature, and in general the technical results reported are in good agreement. The EPA reviewed the available literature over a year ago and summarized its findings in the draft of the "Technical Report on Stationary Gas Turbines"[26]. In September of 1974, the EPA published a draft version of the "Proposed Standards of Performance for Stationary Gas Turbines"[27]. The suggested standards are: NO_x emissions not to exceed 55 ppm by volume, referenced to 15 percent oxygen (and at the operator's discretion, adjusted for efficiency) when gaseous fossil fuel is burned. Gas turbines with less than 50 million BTU/hour heat input (i.e., about 5,000 horsepower) are exempted for three years. Although a considerable number of technical papers have been published within the past year, no new findings of significance have been reported.

Since a number of good reports are currently available in the literature, this report will be limited to a brief summary of emission controls for gas turbines. For additional summarized information relative to emission controls for gas turbines, the reader is referred to references 28 and 29. For information related to cost effectiveness, availability of water for water injection, etc., the reader is referred to the EPA draft of the Proposed Standard[27].

1. Water Injection

Water injection has been found to significantly reduce NO_x emissions in gas turbines.[30, 31, 32, 33, 34] The reported effects of water injection on NO_x emissions are shown in Figure 9. With water injected at the same rate as the fuel flow (i.e., water/fuel ratio of one), the reduction in NO_x emissions is on the order of 80 percent. Since the relationship appears to be reasonably consistent for both the liquid and gaseous fuel used in the several models of gas turbines that have been reported in the literature, it appears reasonable to conclude that this relationship would also apply to the gas turbine models used for driving natural gas compressors.

The agreement on the effects of water injection on the CO and HC emissions, however, is not as good. Reported results range from a slight reduction[33] through no significant increase, [30, 31], to a significant increase. [27, 29]. This variation appears to be at least in part due to the amount of water injected and the location into which the water was injected in these various determinations. Also, it appears that the effect of water injection on CO emissions varies in different gas turbines. Reference 29, which reported a significant increase in CO, indicated that any problems due to CO increase would tend to occur at lower power levels. Since the gas turbines driving natural gas compressors normally operate near rated power, it would appear that CO increase due to water injection would not normally become a problem.

Data on the effect of water injection on fuel consumption could not be located in the literature. In the draft EPA Proposed Standards, it was stated that wet methods of control (i. e., water injection) reduce overall turbine efficiency by about 1-1/2 percent. [27]

In summary, water injection appears to be a fairly well proven method for reducing NO_x emissions from large gas turbines. Reductions up to 85 percent have been obtained at a water flow to fuel flow ratio of 1. From a technical standpoint, there is no apparent reason why water injection would not be equally effective on the gas turbines used for driving natural gas compressors. However, an important question remaining to be answered is whether the use of water injection is economically feasible for gas turbines in the size range, application, and location of the units used by the natural gas industry. The reader desiring additional information in this area is referred to reference 27.

2. Steam Injection

There is considerably less amount of reported data for steam injection than for water injection. The literature[35, 36] indicates that NO_x reductions with steam injection are equal to or lower in magnitude than those obtained with water injection. Steam injection, however, in addition to decreasing NO_x emissions, also increases the operating efficiency by increasing the output of the turbine with no change in fuel flow. It should be noted, however, that a net overall gain in efficiency

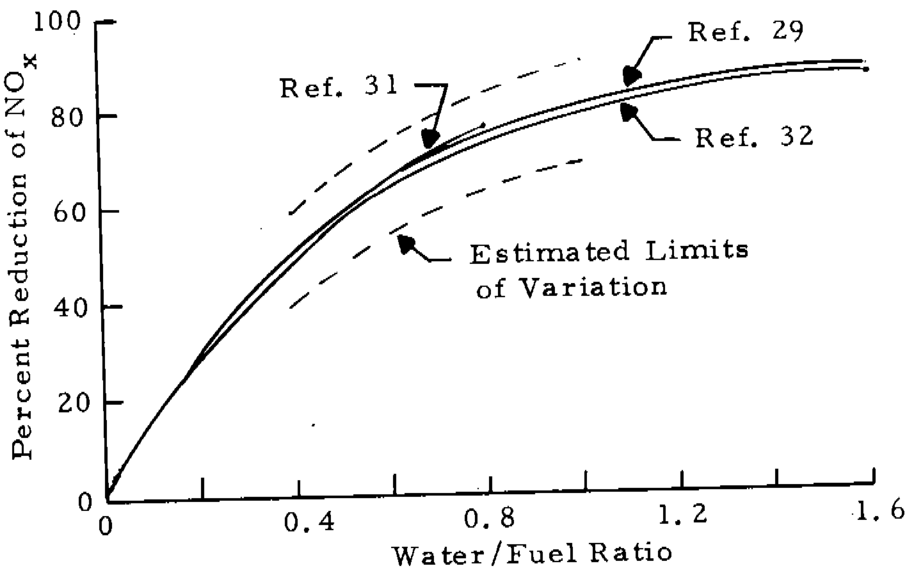


FIGURE 9. AVERAGE EFFECTS OF WATER INJECTION ON GAS TURBINE NO_x EMISSIONS

results only when a supply of waste steam is available. A major drawback of steam injection for most applications is the added complexity of the system required to provide the steam.

3. Exhaust Gas Recirculation (EGR)

Two sources were found in the literature which provided data on the effects of EGR on the NO_x emissions rate from gas turbines. In one of the sources[37], a laboratory burner was used with the goal of meeting the equivalent of the 1976 Federal Emission Standards for Light Vehicles. The recirculated exhaust was cooled to 400°F prior to mixing with the burner inlet air. The reduction in NO_x with 10 percent EGR varied from 35 to 45 percent within the range of 115 to 170 percent stoichiometric air. At 15 percent EGR, the reduction in NO_x varied from 65 to 70 percent within the range of 115 to 160 percent stoichiometric air. The second study,[32] utilized two combustors in series to simulate the recirculation of exhaust gas. In this evaluation, the inlet temperature to the second combustor was apparently maintained at 600°F with and without simulated recirculated exhaust. Using natural gas, a NO_x reduction of 30 percent was obtained with a recirculation rate of 26 percent. The overall fuel/air ratio at peak load in this combustor was about 0.018 (or approximately 330 percent stoichiometric air). The results are summarized as follows:

	Nominal Percent		
	EGR	Reduction in NO_x	Stoichiometric Air
Study #1[37]	10	40	140
	15	65	135
Study #2[32]	25	30	330

This data seems to indicate that there is no relationship between percent EGR and the resulting percent reduction in NO_x. However, an important question is, would there be agreement if the EGR values were adjusted to a common percent of stoichiometric air. (Note that in a gas turbine having 400 percent of stoichiometric air, nominally 75 percent of the EGR would be air and only 25 percent combustion products.) Since appropriate formulas could not be found in the literature, the relationships were developed and are included in Appendix D. Using these developed relationships, the adjusted values are summarized as follows:

	Nominal Percent		
	EGR		Reduction in NO_x
	Gross	Effective	
Study #1[37]	10	8	40
	15	13	65
Study #2[32]	25	8	30

These data indicate that a nominal NO_x reduction of between one-third and one-half is obtained with an effective EGR rate of 10 percent. This NO_x reduction on the basis of the effective EGR rate is in the same order of magnitude as has been normally obtained with heavy-duty gasoline fueled spark-ignition engines.[38]

The air/fuel ratios in the gas turbines measured in the initial phase of this project ranged from about 60 to 110. Using the stoichiometric ratio for natural gas (approximately 17), this represents about 350 to 650 percent of stoichiometric air. If it is assumed that a 50 percent reduction in NO_x can be obtained with an "effective EGR rate" of 10 percent, the following gross EGR rates would be required.

Turbine Overall Air/Fuel Ratio	Approximate % EGR to Obtain 50% Reduction of NO_x
60	30
110	60

Note: Assumed value based on limited available data. Actual NO_x reduction in various gas turbines would be estimated to range between values of about 30 to 60 percent.

Calculated using: $$\% \, EGR_G{}^* = \frac{A/F_G}{A/F_S} \left(\%EGR_E - \frac{\%EGR_E{}^2}{100} \right)$$

*See Appendix D for derivation of the equation

It would be difficult to cool and recirculate 30 to 60 percent of the total exhaust gas, which is on the order of 300,000 to 400,000 lbs/hr for a 10,000 hp gas turbine. Therefore, it appears reasonable to conclude that EGR does not currently appear to be a practical method for obtaining large NO_x reductions in the gas turbines used to drive natural gas compressors.

4. Other Emission Control Methods

Since the production of NO_x is temperature and time dependent, a reduction in either will reduce the NO_x emissions. Some methods for lowering the temperature include: increasing air/fuel ratio in the combustion area and improved mixing within the combustion area. Some methods for reducing residence time include: increasing flow velocity and earlier addition of the quench air. In the literature these methods are generally called "dry" methods as opposed to water and steam injection which are called "wet" methods.

These "dry" methods have generally been used in various combinations by the manufacturers to obtain what they consider the maximum achievable reduction. The actual hardware modifications, required to the gas turbines to achieve the NO_x control, are currently considered to be proprietary and have seldom been described. The maximum "dry" method reduction in NO_x found in the literature was 42 percent.(29) This result was obtained in a low pressure burner rig. The amount of reduction attainable appears to be dependent to a large extent on original criteria used in the design of the gas turbine. In general, it appears that gas turbines producing relatively high NO_x emissions are good candidates for these "dry" emission control methods. On the other hand, those units inherently producing relatively low NO_x emissions often feature some of the "dry" control methods and may not be good candidates for additional significant reductions. In general, it seems reasonable to conclude that without some major technical breakthrough, "dry" control methods cannot currently be relied on for more than possibly a 10 to 40 percent reduction of NO_x emissions from units in current production, depending on the specific unit. These currently attainable "dry" control reductions, however, are generally insufficient to enable the gas turbines with over 50 million BTU/hour heat input to meet the suggested standards.

5. Other Considerations

An area discussed in the literature is the effect of organic nitrogen inherent in the fuel. A significant portion of the organic nitrogen in the fuel ends up as NO_x emissions in the exhaust.(28, 39) This area has essentially no application to gas turbines fueled with natural gas, however, since natural gas generally contains a negligible amount of organic nitrogen.

Current technology catalysts appear to have essentially no application to natural gas fueled gas turbines. Although oxidation catalysts could be used to reduce CO and HC, these emissions are currently at very low levels in gas turbines. Any significant benefits from further reducing these low CO and HC emission levels using an oxidation catalyst are doubtful. Current technology reduction type catalysts, for reducing NO_x emissions, require exhaust containing a significant amount of CO (i.e., about 1 to 2 percent) and a low amount of oxygen (i.e., under 0.5 percent). Since the exhaust of the gas turbines used for driving natural gas compressors contains high concentrations of oxygen, current technology reduction type catalysts are not applicable to these gas turbines.

Regenerative gas turbines utilize a portion of the heat energy in the exhaust and thereby increase the operating efficiency (i.e., bhp-hr/lb of fuel). This increase in efficiency, however, is normally associated with an increase in NO_x emissions. In the suggested standards, the EPA allows the use of an equation which can be used to adjust the measured

NO_x emission level as a function of efficiency. For the gas turbines used in natural gas compression, the equation is as follows:

$$\text{Corrected } NO_x = \text{Measured } NO_x \cdot \frac{1}{1 + \frac{11{,}000 - BSFC}{11{,}000}}$$

From data provided by the General Electric Company, it appears that the increase in brake specific NO_x emissions with regeneration is approximately equal to, or slightly greater than, the improvement in brake specific efficiency[40]. There was insufficient data available, however, to make an analytically acceptable determination of whether or not the NO_x correction factor for efficiency, as proposed by EPA, is sufficient to offset the increase in NO_x produced by regenerative gas turbines. From this very limited available data, it appears that regenerative gas turbines (after using the equations to adjust for the improvement in efficiency) produce adjusted NO_x emissions approximately equal to or somewhat higher than that produced in non-regenerative gas turbines.

B. Reciprocating Gas Engines

The sources of data for reciprocating gas engines include both published sources and some unpublished data obtained from the manufacturers of over 1000 horsepower natural gas engines used by the natural gas industry. In 1973, four manufacturers (Cooper-Bessemer, Dresser-Clark, Ingersoll-Rand, and Worthington) accounted for approximately 97 percent of the total installed horsepower of reciprocating gas engines over 1000 hp reported in the AGA Directory[2]. Each of these four manufacturers have conducted some evaluations of the effect of engine variables on exhaust emissions. Primarily this has involved changing the load, speed, scavenging air, air/fuel ratio, and spark timing. These and other control technology evaluations conducted are summarized in Table 20. In addition to the data listed in Table 20, the initial phase of PR-15-61 included eight determinations of the effects of torque variation, eleven of speed variation, eleven of ignition timing, and six of scavenging air rate.[1]

1. General Discussion of Effects of Engine Variables on Exhaust Emissions

As previously stated, most of the evaluations in this area were conducted during or around 1972. Essentially all of this data has been reported at least once and in several cases a number of times. A number of the more comprehensive evaluations have been summarized in the report "Stationary Internal Combustion Engines in the United States".[4] Rather than repeat all these data, this report will primarily concentrate on evaluating the applicability of these data to the control of emissions

TABLE 20. CONTROL TECHNOLOGY EVALUATIONS OF RECIPROCATING GAS ENGINES

Emission Control Parameter or Method	Companies that Have Conducted Evaluations		Total Engine Models Evaluated
	Four Mfg.	AGA Companies	
Torque	4*	2	10
Speed	4*	1	10
Intake Air Temp.	2	1	4
Air/Fuel Ratio	3	0	3**
Turbocharge	0	0	0
Scavenging Air	3*	2	5**
Ignition Timing	4*	2	6
Exhaust Backpressure	1	0	1
EGR	1	1	2
Water Induction	1	1	2***
Water Injection	1	0	1
Steam Injection	0	0	0
Oxidation Catalysts	0	0	0
Reduction Catalysts	0	1	1
Stratified Charge	1*	0	-
Design Modification	1*	0	-

*The results could not be obtained from one of the manufacturers in each area marked.

**These quantities are subject to interpretation.

***Labeled as being water injection. Water was introduced into the intake in quantities below 25% of fuel.

for natural gas compressor engines. One area of extreme importance that has been briefly mentioned in some reports and completely overlooked in others, is that when one engine operating parameter is intentionally changed, one or more other engine parameters are also changed. In some cases the operating parameter that was indirectly changed can have more of an effect on NO_x production than the parameter that was directly changed. This area will be discussed in detail in the sections on the effects of torque and intake air temperature.

2. Effects of Engine Torque on Emissions

This parameter, either at constant speed or constant horsepower, (obtained by varying the speed), has been the most widely evaluated with respect to effect on emissions. The reason for this is probably two-fold. It's easy and quick to do and generally results in an apparent large effect on NO_x emissions.

Initially, consider the relationship of brake mean effective pressure (BMEP) on NO_x emissions. BMEP is equal to a constant times the torque divided by the displacement. Therefore, in a given constant displacement engine, BMEP is directly proportional to torque. Figure 10 shows data reported by Cooper-Bessemer and reported in the final report of the PR-15-61 baseline emissions survey. These data are for a number of different engine models and only single point values of NO_x emissions at rated horsepower vs the manufacturer's specified BMEP at rated horsepower are given. These data indicate that there is no generic relationship between NO_x emissions and rated BMEP.

Previous Tables 4 through 6 indicated that in a given engine the NO_x emissions rate generally increases with increase in torque (i.e., increase in BMEP). As indicated in Figure 10, there is no generic relationship between NO_x emissions and BMEP. What parameter or factor, therefore, is responsible for the general increase in NO_x emissions rate with increase in BMEP in a specific engine?

To simplify this discussion of the relationship between NO_x emissions rate and torque in a specific engine, naturally aspirated, two-cycle, fuel injected natural gas engines will initially be considered. In such an engine, the air flow varies as a function of the speed and is essentially unaffected by the torque output. A reduction in torque at constant speed is associated with a reduction in fuel flow; and this reduction in fuel flow has essentially a direct effect on the trapped air/fuel ratio. (Trapped air/fuel ratio is defined here as the ratio that is present in the cylinder at the time ignition occurs.) It is this change in air/fuel ratio that apparently has the major effect on NO_x emission. The well accepted relationship of air/fuel ratio versus emissions is shown in Figure 11. Natural gas engines operate on the lean side of stoichiometric and generally on the lean side of the air/fuel ratio at which maximum NO_x emissions are produced. Therefore, relatively small additional leaning of air/fuel ratio can have significant effects on NO_x emissions.

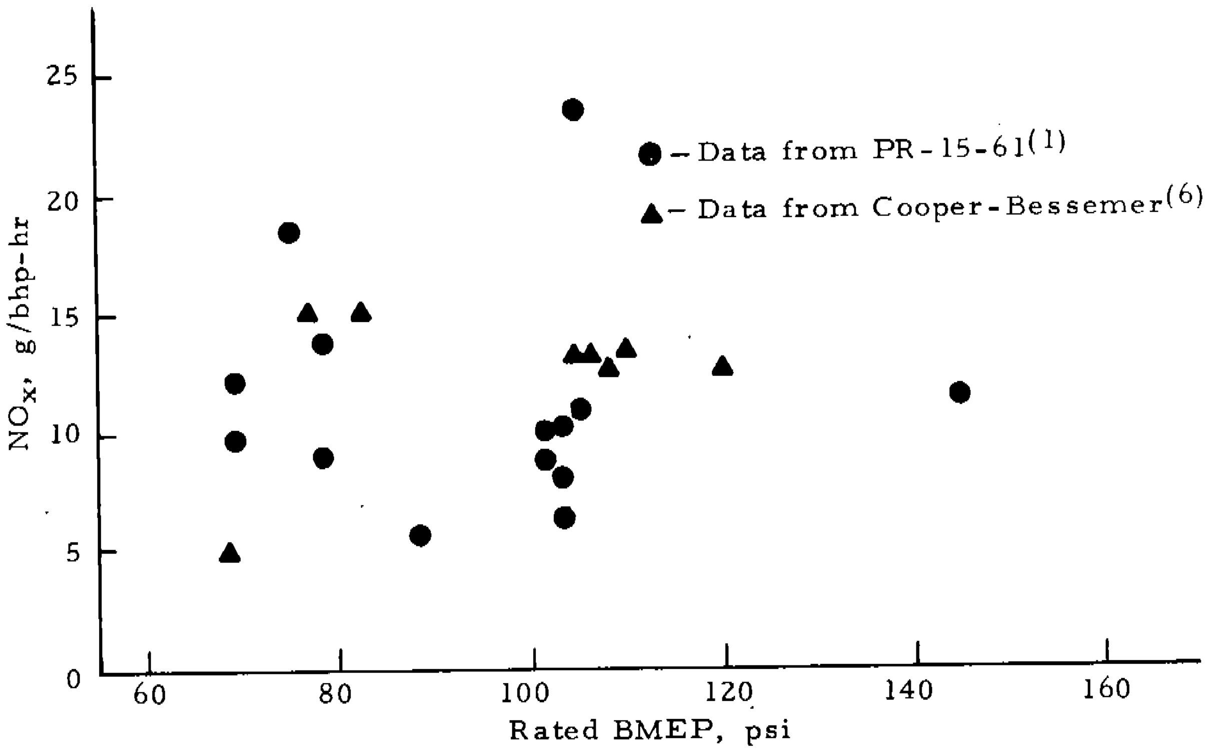


FIGURE 10. NO_x VS RATED BMEP IN VARIOUS ENGINE MAKES AND MODELS

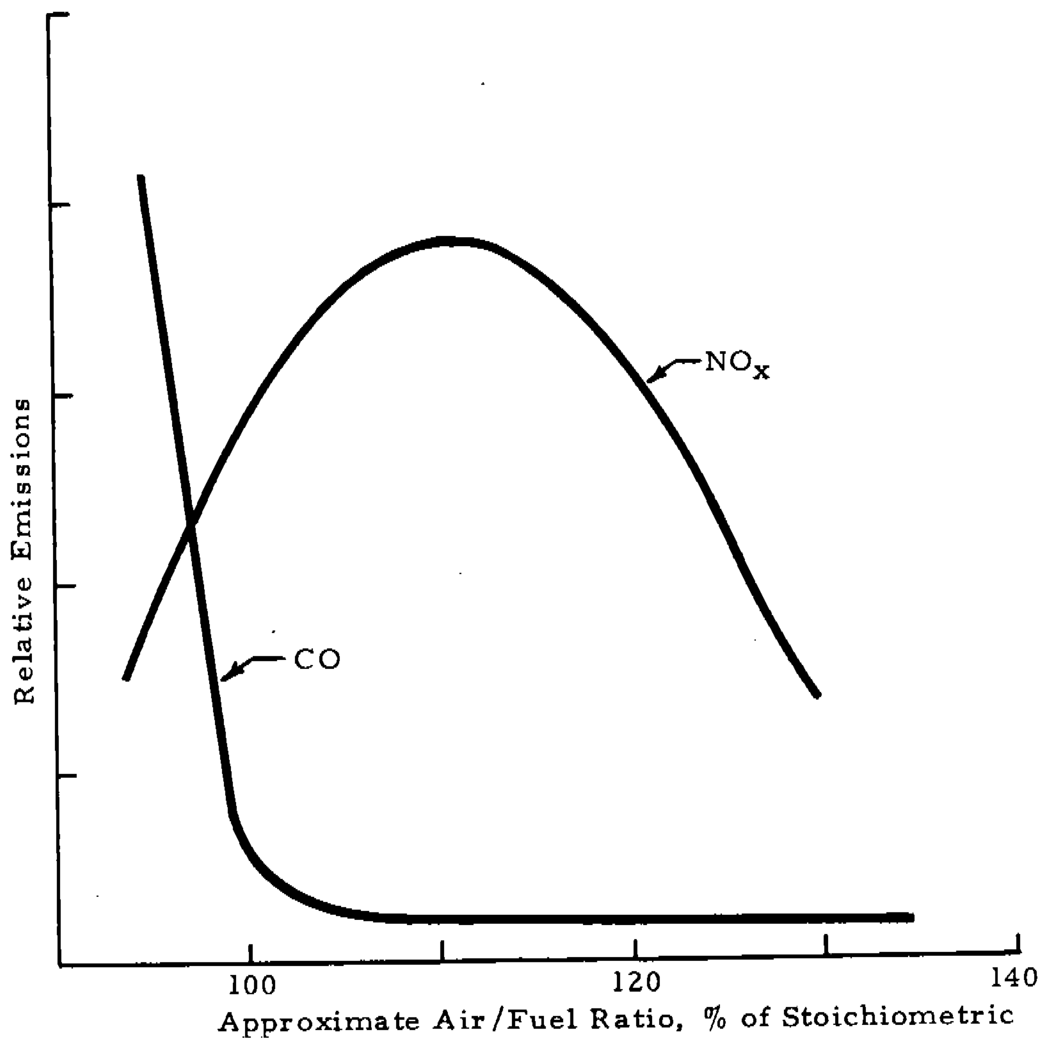


FIGURE 11. RELATIVE EFFECT OF AIR/FUEL RATIO ON NO_x AND CO EMISSIONS FROM SPARK-IGNITED PISTON ENGINES

An important question is what would be the effect on NO_x emissions if the air/fuel ratio were held constant while reducing the fuel flow to reduce the torque output. Unfortunately, this evaluation has apparently never been made. The available data, however, indicates that if the air/fuel ratio were held constant in an engine while fuel flow (and therefore torque output) were decreased, the effect on the brake specific NO_x emission rate would be minimal.

What about the use of derating (by reduction of engine torque) as an emission control technique for new production engines? Derating should be effective in naturally aspirated and constant pressure turbocharged engines having a relatively low air/fuel ratio and high brake specific NO_x emissions at rated operating conditions. One penalty of derating, however, is that the initial cost per unit of horsepower would increase, in essential inverse proportion to the amount of derating, (i.e., if an engine model of 1000 rated horsepower is derated to 900 horsepower, 11 engines rather than 10 would be required to obtain essentially the same total horsepower). Another penalty of derating is that generally the brake specific fuel consumption is increased.[1, 6, 7, 8, 9, 15] No consistent increase in BSFC, however, could be derived due to the scatter in the available data.

In summary, the available data indicates that reductions in brake specific NO_x emissions obtained by derating (by reducing the fuel injected and thereby the torque output) may be primarily due to the associated change in air/fuel ratio rather than the reduction in power output. Derating is generally associated with some increase in BSFC. The increase in BSFC and the decrease in brake specific NO_x emissions resulting from derating appear to vary significantly depending on the specific engine configuration and operating parameters (i.e., naturally aspirated, constant pressure turbocharge, air/fuel ratio control, etc.).

3. Effect of Engine Speed on Emissions

The limited available data indicates that speed, per se, has an indeterminate effect on brake specific NO_x emissions. In the engine shown in subsequent Figure 13, the NO_x increased with increasing engine speed, while others have shown an opposite effect. Two evaluations involving variation in speed have also determined the trapped air/fuel ratio. These evaluations (shown in subsequent Figures 12 and 13) indicate that the resultant change in air/fuel ratio may be the primary factor effecting the changes in NO_x emissions. Increasing the engine speed beyond rated could have a detrimental effect on engine operation and durability.

4. Intake Air Temperature

In the section on Emissions Impact, it was discussed how significant changes in NO_x emissions (i.e., on the order of a 10 percent change in NO_x emissions per 10°F temperature change) have occurred in engines with changes in intake (or manifold) air temperature. The data in subsequent Figures 12 and 13, however, indicate that the change in NO_x emissions may be primarily due to the resultant change in air/fuel ratio. It is postulated that in engines having air/fuel ratio control, the effects of changes in intake air temperature on NO_x emissions may be minimal.

In a study of automotive gasoline engines, temperature was found to have an indeterminate effect on NO_x emissions.[41] Out of a total of six gasoline engines evaluated: three had higher NO_x emissions at 200°F than at 75°F and three had lower NO_x emissions at 200°F than at 75°F. The composite average brake specific NO_x values of all six engines at 75°F and 200°F were almost identical.

From the very limited data available, it would appear that intake air temperature per se may not be a very effective method for controlling NO_x emissions. However, as the air temperature decreases, the density of the air increases. Therefore, the charge density of the air within the engine cylinder increases and, with a constant amount of fuel injected, the air/fuel ratio increases. This increase in air/fuel ratio results in a decrease in NO_x emissions. The net result is that lowering the intake air temperature can indirectly significantly reduce NO_x emissions in naturally aspirated and constant pressure turbocharged gas engines. This effect of intake air temperatures is of primary practical importance with turbocharged engines, where the air temperature out of the turbocharger can be significantly above ambient. Intercooling the air between the turbocharger and the engine can be utilized as a method for emission control. This has been effectively indicated in previous Figures 9 and 10, where the higher rated BMEP engines produced NO_x emissions that were no higher than the emissions produced by lower rated BMEP engines. In general, the higher BMEP engines were turbocharged and intercooled.

5. Air/Fuel Ratio

As the air/fuel ratio increases above the ratio at which maximum NO_x is produced, there is less fuel available per unit of air charge. This results in lower combustion temperatures and lower NO_x emissions.

Figures 12 and 13 show the relationship between the brake specific NO_x emissions and the air/fuel ratio. For the two-cycle engine, it is the trapped air/fuel ratio, not the overall, which is shown. Obtaining the trapped air/fuel ratio in two-cycle engines is difficult. The various air/fuel ratios shown resulted from changes in other engine parameters. In all of the evaluations shown, a decrease in NO_x emissions was always associated with an increase in air/fuel ratio. From this data it appears

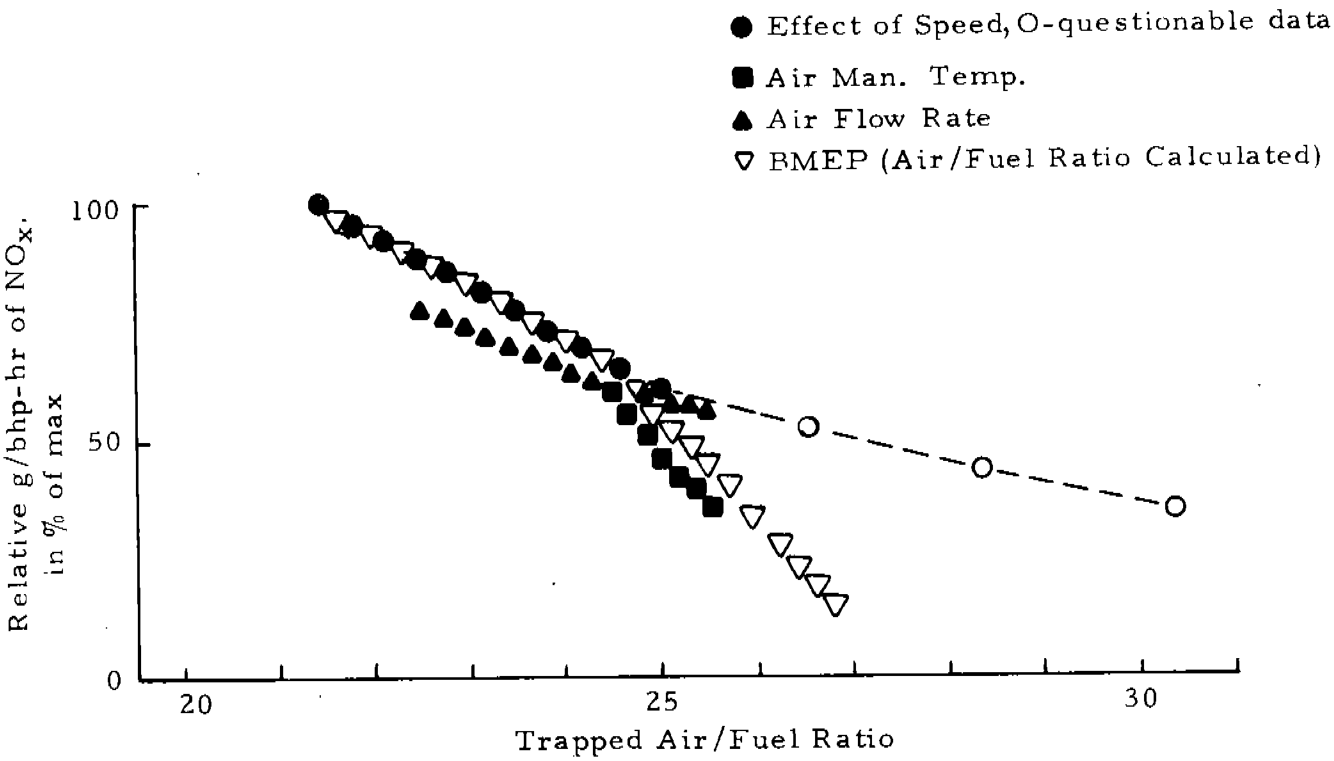


FIGURE 12. EFFECT OF ENGINE PARAMETERS ON NO_x EMISSIONS(42)
C-B GMVA-8 2-Stroke Atmospheric Engine

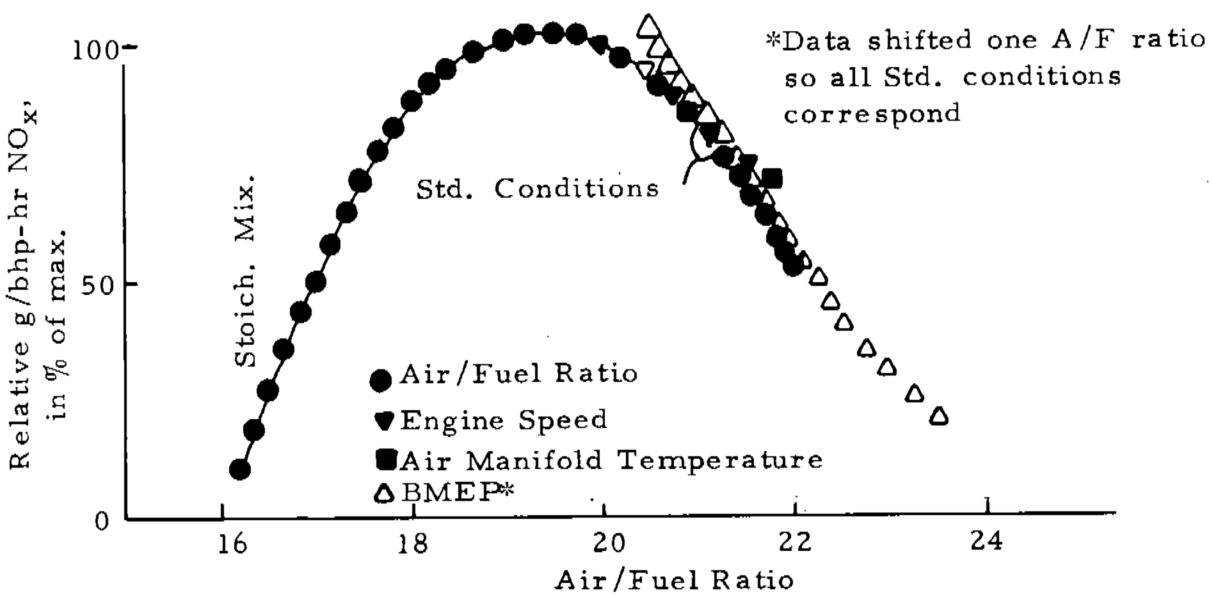


FIGURE 13. EFFECT OF ENGINE PARAMETERS ON NO_x EMISSIONS(8)
IR KVGR 4-Cycle NA Gas Engine

reasonable to conclude that the change in air/fuel ratio was a significant factor in every one of these evaluations. In some of the evaluations, it appears possible that the resultant changes in air/fuel ratio, rather than the engine parameter directly varied, may have been responsible for the total amount of change in NO_x emissions.

As shown in Figure 13, variation of the trapped air/fuel ratio can have a very significant effect on NO_x emissions. Those engines currently having air/fuel ratios which produce high NO_x emissions are potential candidates for control of NO_x emissions by increasing the air/fuel ratio. An increase in air/fuel ratio is obtainable by various means, including: increasing the boost pressure, cooling the intake air, derating (i. e., decreasing the fuel injected at constant speed) or increasing the engine speed at constant brake-horsepower output. Each of these methods is individually discussed in this report.

Conversely, those engines having low emissions due to a designed high air/fuel ratio may not be good candidates for further NO_x control through an increase in air/fuel ratio. (Note - it is postulated, but cannot be proven with the limited available data, that those natural gas engines which produce low levels of NO_x emissions operate at high trapped air/fuel ratio. Unfortunately, determination of the trapped air/fuel ratio is very difficult in two-cycle natural gas engines). Of all the engine parameters studied, air/fuel ratio appears to have the most significant effect on NO_x emissions and the greatest potential as a design criteria for emission control.

6. Turbocharging

No direct determinations of the effects of turbocharging on emissions were available. Based on the results plotted in previous Figure 10, it appears that turbocharging may not have a direct effect on NO_x emissions. In the data plotted in this figure, high BMEP is generally associated with high turbocharge boost pressures.

In engines having relatively low air/fuel ratios and consequently high NO_x emissions, it may be possible to effectively use turbocharging to reduce the emissions. If the boost pressure were increased while holding the amount of fuel injected constant or only slightly increased, the resultant increase in air/fuel ratio could effectively reduce NO_x emissions.

7. Scavenging Air

In the tests conducted, an increase in scavenging air flow was generally associated with an increase in scavenging air pressure. This increase in pressure increases the charge density of air within the cylinder and at constant fuel flow increases the air/fuel ratio. Therefore, it is not the change in scavenging air flow rate that affects the NO_x emissions, but rather it is generally the resulting change in air/fuel ratio that results from the higher scavenging air pressure.

8. Ignition Timing

The effects of ignition timing on NO_x emissions are illustrated in Figure 14. It should be noted that even variation in ignition timing effects other engine parameters. Depending on how these effects are compensated for has a significant effect on the resulting NO_x emission rate. Based on the data shown in Figure 14, average reduction in NO_x emissions up to 16 percent have been obtained by retarding the ignition timing. Unfortunately, the evaluations involving ignition timing do not provide data necessary to evaluate the associated effects on BSFC. With the Cooper-Bessemer GMVA-8 and the GMWA-6 engines shown, the BSFC increased approximately 1 percent for each degree of ignition retard.

In the PR-15-61 data, the percent change in NO_x emissions in ten different engine models ranged from a seven percent reduction to a two percent increase per degree of ignition retard. Due to the very limited data taken relative to the effects of ignition timing in the initial phase of PR-15-61, these values cannot be taken as absolutes. However, these PR-15-61 data, along with the other data shown in Figure , indicate that there is considerable variation of the effect of timing on NO_x emission rate among different engine models and that no generally drastic reduction in NO_x emissions can be realistically attained by retarding the ignition timing.

9. Exhaust Backpressure

Increasing exhaust backpressure is a way of increasing charge density while reducing exhaust scavenging efficiency. In a Cooper-Bessemer GMVA-8 engine, the NO_x emissions rate decreased approximately 37 percent at 6 inches of mercury backpressure increase from the base condition.[42] However, associated with this decrease in NO_x emission was an increase in BSFC of about 8 percent. This evaluation, although conducted in a laboratory, took into account the additional power requirement for the air blower to produce the higher outlet pressure required. From these limited data, it appears that increasing exhaust backpressure would be among the most inefficient methods for reducing NO_x emissions.

10. Exhaust Gas Recirculation (EGR)

With EGR, a portion of the exhaust gases are introduced into the intake manifold. These exhaust gases, that are recirculated, directly

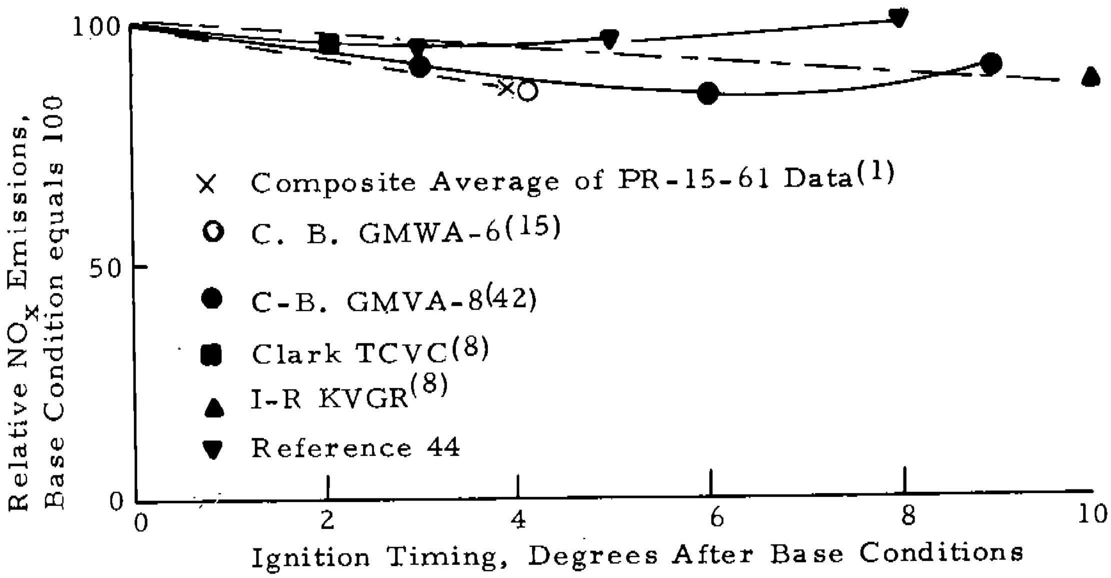


FIGURE 14. EFFECT OF IGNITION TIMING ON NO_x EMISSIONS

decrease the mass flow rate of the exhaust, decrease the concentration of oxygen in the charge, and increase the heat capacity of the charge. The last two factors effectively lower the combustion temperature and are primarily responsible for the resultant reduction in NO_x emissions. The use of EGR with gas turbines was discussed in Section III. A.3 . of this report. That discussion and the formulas developed also generally apply to the two-cycle natural gas engines.

In the two-cycle reciprocating engines evaluated in this study, air flow rates of about 200 percent or more of stoichiometric were quite common. With the assumption of a 50 percent reduction in brake specific NO_x for a 10 percent "Effective EGR Rate", a gross EGR rate of 18 percent would be required to obtain a 50 percent reduction in NO_x in an engine having an air rate of 200 percent of stoichiometric. This has been found to agree reasonably well with the results obtained in an actual evaluation of EGR in a two-cycle natural gas fueled engine as follows:(43)

EGR Rate, %		NO_x Reduction, %	
Gross	Effective*	ppm	g/bhp-hr**
0	0	0	0
5.1	3	6	6
8.8	5	21	23
11.5	7	18	20
17.2	10	28	34
Decreased Nozzle Area			
18.4	10	35	43

*Effective rate calculated using the formula derived in Appendix D .

**Estimated using: ppm % Reduction x 100/100-Gross EGR %

It has been reported that for EGR to be effective in natural gas engines, it was necessary to cool the exhaust gases.(43, 44) Recycling without cooling the exhaust gas resulted in detonation and stalling of the engine. Based on these limited data, the maximum practical reduction in NO_x, using EGR, appears to be no greater than 50 percent. The effects of EGR on BSFC, performance and durability have not been adequately determined for natural gas engines.

11. Water Induction

Two evaluations termed water injection by their investigators have been reclassified as water induction for purposes of this report. (9, 44) In both of these evaluations, the water was introduced or inducted into either the scavenging air stream or intake manifold at a low flow rate relative to the fuel flow (i.e., approximately at rates of

14 and 20 percent, at most). As one would expect based on these relatively low flow rates of water, the reductions in NO_x emissions were not very significant. The amount of water that can be inducted is limited to the amount of water necessary to saturate the air. Therefore, water induction has limitations as a method for obtaining significant reduction in NO_x emissions.

12. Water Injection

Water injection, for purposes of this report, is defined as water that is injected into the combustion chamber. In one evaluation of water injection in a four-cycle natural gas engine, an approximate 60 percent reduction in NO_x emissions was obtained at a water to fuel ratio of 1 pound water per 1 pound of fuel.[42] No information was available on the effect of water injection on engine reliability and durability. Direct water injection has apparently never been evaluated in a two-cycle gas engine. Over 75 percent of the large (over 1000 hp) reciprocating gas engines currently used for natural gas transmission are two-cycle.

13. Steam Injection

No data was available on the effects of steam injection on emissions in reciprocating gas engines. Based on the reported need to cool the recirculated exhaust gases when EGR was used[43, 44], it appears doubtful that steam injection could be effectively used for NO_x emission control in reciprocating gas engines.

14. Oxidation Catalysts (CO and HC)

Oxidation catalysts have been found to be effective in automotive applications for reducing CO and unburned HC emissions. Since reciprocating gas engines normally operate air rich, oxidation catalysts could be used. As found in the Emissions Impact evaluation, however, the CO and non-methane HC emissions contribution from reciprocating gas engines used in natural gas compression are only a fraction of one percent of the national total. For this reason, the HC and CO emissions from reciprocating gas engines do not appear to be very significant; precluding the need for oxidation catalysts.

15. Reduction Catalysts

One evaluation was reported in the literature[44] in which a portion of the exhaust from a four-cycle natural gas engine was passed through a reduction catalyst. By running the engine fuel rich, reduction of over 95 percent in the NO_x was achieved in some cases. Two of the drawbacks of this approach were stated to be high initial costs and poor fuel economy. Although research has been reported with high oxygen exhaust gases, using ammonia as the reducing agent,[4] no reduction catalysts are currently available for NO_x control that are effective in the oxidizing atmospheres typical in the majority of the reciprocating gas engines either installed or in current production.

16. Stratified Charge

This study failed to uncover any data concerning the application of the stratified charge combustion process to natural gas engines. The primary purpose of stratified charge in gasoline engines is to enable operation at leaner mixtures than can normally be attained with a homogeneous fuel-air charge. This lean mixture results in lower CO and NO_x emissions. With natural gas, it is possible to operate an engine as lean as 130 percent of stoichiometric air without misfiring the engine. Therefore, it appears that stratified charge has limited application to natural gas engines.

17. Engine Design Modifications

This area was discussed with each of the four major domestic gas engine manufacturers. It was indicated that, although some thought has been given to design modifications for emission control, very little work has been done in this area. It was further indicated that at the present time, any data developed in this area was considered to be proprietary and therefore could not be released.

IV. INFORMATIONAL ACTIVITIES

Early in the current phase of this project, summary presentations of the final report of the baseline emissions survey(1) and of the plans for continuation of the project were separately made to: (1) the gas turbine manufacturers, (2) reciprocating engine manufacturers, and (3) the Environmental Protection Agency. During these presentations, the manufacturers and the EPA were asked for their assistance in obtaining information essential to the continuation of this project.

Each of the presentations consisted of:

(1) Welcoming remarks by the Chairman of the AGA Supervisory Committee.

(2) A briefing by a representative of Southwest Research Institute on the results of the baseline emission survey, followed by discussion.

(3) A briefing by SwRI personnel on the plans for the current phase of the project, followed by discussion.

(4) A request for assistance in obtaining the information essential to this current phase of the project.

(5) Distribution of the final report on the baseline emissions survey(1) by a representative of the American Gas Association.

In the March 20, 1974 session for the gas turbine manufacturers, the attendance included representatives from the General Electric Company, Turbo Power & Marine Systems, Inc., and the Solar Division of International Harvester Company.

In the March 21, 1974 session for reciprocating engine manufacturers, the attendance included representatives from Cooper-Bessemer Co., Dresser Clark Division of Dresser Industries, Inc., Ingersoll-Rand Co., Worthington-CEI, Inc., Fairbanks Morse Division of Colt Industries, DeLaval Turbine, Inc., White Motor Corporation, and the Diesel Engine Manufacturers Association.

The presentation made, on March 22, 1974, to the Environmental Protection Agency at Research Triangle Park in North Carolina, was attended by ten individuals representing five different branches or sections of EPA.

In addition to the preceding presentations, requests have been made that a representative of SwRI present the results of the baseline emissions survey at three different industrial and professional organization meetings and conferences. The meetings and conferences at which presentations are scheduled to be given include the following:

(1) Natural Gas Industry Regional Environmental Symposium in Pittsburgh on February 11-12, 1975

(2) ASME Diesel and Gas Power Meeting in New Orleans on April 6-10, 1975

(3) AGA Gas Transmission Conference in Bal Harbor, Florida on May 19-21, 1975

V. SUMMARY AND CONCLUSIONS

This phase of AGA project PR-15-61, as reported in this report, involved three primary areas: (1) estimation of national emissions impact, (2) control technology assessment, and (3) informational activities. Each of these areas is summarized as follows:

A. Estimation of Emissions Impact

State and national emissions impact of compressor engines over 1000 horsepower in AGA member companies were calculated using a special computer program prepared for this purpose. The methods developed are also suitable for determination of local emissions impact provided suitable input data are available. The operating data inputs required are: location, engine quantity by model at each location, engine rated horsepower, and engine annual hours of operation. The overall total gas industry national emissions impact was estimated using direct extrapolation of the values obtained for the AGA member companies to the total gas industry compressor horsepower.

It is estimated that in 1973 the total gas utility industry operated 85 billion brake horsepower-hours and produced approximately 784,000 tons of NO_x, 100,000 tons of CO, 293,000 tons of total HC and 15,000 tons of non-methane HC. These values represent 3.6 percent of the NO_x, 0.1 percent of the CO and 1.1 percent of the HC from all sources and 7.2 percent of the NO_x, 0.4 percent of the CO and 2.5 percent of the HC from stationary sources (all sources not classed as transportation). Percentages are based on national emissions estimates for 1971, the latest data available. About five percent of the HC from the gas industry is non-methane.

The 1973 compressor horsepower directly evaluated in this project was 3,331,908 for gas turbines and 7,662,963 for piston engines. This is approximately 74 percent of the 1973 total gas utility industry installed compressor horsepower of 14,850,000. No source of data could be found which gave a reliable breakdown of the approximate 4 million gas utility industry horsepower that was not directly evaluated in this study. The assumption was made, and discussed, that this 4 million horsepower produced emissions at the same overall average rate as the approximately 11 million horsepower for which suitable data was available.

For 1973, the AGA member companies reported 10,995,000 compressor horsepower for engines over 1000 horsepower. The resultant bhp-hrs operated and emissions produced were: 63 billion bhp-hrs operated; and 581,000 tons of NO_x, 74,000 tons of CO and 216,000 tons of total HC. Of the 216,000 tons of total HC, only about 5 percent, about 11,000 tons, was non-methane. The gas turbines, with about 30 percent of the installed horsepower and bhp-hr operated, produced about 5 percent of the NO_x emissions.

Emission factors were determined, estimated or assigned for each engine family, using available emissions data. The baseline emissions survey conducted in the initial phase, constituted the primary data source used to estimate engine emission levels in the evaluation of emissions impact. The majority of the emission factors selected were discussed with the respective manufacturers. The average operating load factor was found to be 96 percent of rated load from operating data supplied by the gas transmission companies.

A problem encountered with much of the data obtained from sources other than PR-15-61 was that only processed data was provided and no consistent criteria were used in the processing. In a few cases, considerable disagreement was encountered between engine emission values obtained from different sources. Insofar as possible, an attempt was made to resolve these differences. An area which could not be resolved was the gas turbine manufacturers' reported values for gas turbine NO_x emissions which were generally about 50 percent higher than values determined in PR-15-61. Since the gas turbines produce only about 5 percent of the total NO_x emissions emitted by engines used in natural gas transmission, this disagreement is essentially insignificant to the overall national gas transmission industry emission impact value.

It was determined that atmospheric and engine operating conditions can have a significant effect on the emission levels of piston engines and gas turbines. However, analytically acceptable correction factors were not available. For humidity and load, areas in which somewhat reasonable data were available, correction factors were assumed for use in the emissions impact evaluation. Although load and atmospheric factors can have a large effect on individual engine model emission factors, the effect of these factors on the overall nationwide emissions impact is expected to be small.

Several considerations should enter into any evaluation of the significance of the emissions impact and two of these will be mentioned. First, the map published by the FPC of major natural gas pipelines illustrates that generally pipelines are not located in densely populated sections of the country. Second, compressor stations are generally not located within urban areas. Depending on how NO_x is considered, the emissions from specific compressor stations may or may not be significant. One useful determination would be to evaluate the impact of concentrations of NO_x in the immediate vicinity of compressor stations. Another would be to evaluate the contribution of natural gas compression to the two air quality control regions, Chicago and Los Angeles, which are reported to exceed the national ambient air quality standard for NO_x.

B. Control Technology Assessment

In the evaluation of emissions impact, it was determined that NO_x was the only emission of significance from natural gas compressor engines. Therefore, this assessment of emission control technology concentrated on methods for reducing NO_x. The draft proposed standard for gas turbine NO_x emissions is 55 ppm, corrected to 15 percent oxygen and 11,000 BSFC, for new units of 50 million Btu per hour heat input and greater (i.e., about 5000 horsepower). Spark ignited reciprocating engines are subject to study for inclusion in future NO_x standards. A draft proposal is not expected before late 1975.

For gas turbines, both "wet" (i.e., using water) and "dry" (i.e., not using water) methods were found to be effective for reducing NO_x emissions. With the "wet" methods, NO_x emissions can be reduced by approximately 80 percent at a water flow rate equal to the fuel flow. Gas turbine combustion efficiency did not appear to be significantly affected by the wet methods of control. The only source reporting efficiency estimated a 1.5 percent decrease (i.e., fuel flow increased by 1.5 percent). The primary shortcoming with water injection appears to be related to economics, an area not covered in this evaluation.

The "dry" methods of emission control primarily consist of design modifications which tend to reduce the temperature and/or the residence time in the combustion area. Reduction of either the temperature or the residence time results in a reduction in NO_x emissions. These dry methods have been reported to achieve a maximum reduction in NO_x emissions of 42 percent. It is estimated that current technology "dry" methods of control cannot be relied on for more than possibly a 10 to 40 percent reduction of NO_x emissions from units in current production. Of the two methods, the "wet" method appears to be the only control approach currently able to meet the suggested 55 ppm NO_x level.

For reciprocating gas engines, most emission control evaluations that have been reported involve variations of engine operating parameters such as torque and speed. It was found, in most of these evaluations, that the change in the operating parameter resulted in a change in air/fuel ratio which was either partially or totally responsible for the NO_x reduction. Air/fuel ratio appears to be the single most important parameter affecting reciprocating engine NO_x emissions. Very limited data were available on methods such as: exhaust gas recirculation, water induction and injection, catalysts and stratified charge. It appears, however, that these methods of NO_x control have limited application to reciprocating gas engines.

C. Informational Activities

The results of the baseline emissions survey, conducted in the initial phase of this project, have been separately presented to the gas turbine manufacturers, the reciprocating engine manufacturers, and the Environmental Protection Agency. Other presentations of the baseline survey that either have or will be made, include three different industrial and professional organization meetings and conferences.

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APPENDIXES

TABLE A-1. PISTON ENGINE BRAKE SPECIFIC EMISSION FACTORS USED IN THIS PROJECT

MFG.	MODEL NUMBER	MODEL CODE	ESTIMATED EMISSION FACTORS AT RATED HORSEPOWER, GRAMS/BHP-HR NOX	CO	HC
CB	GMV-ALL	101	17.60	.80	3.50
CB	GMVA	102	12.00	.70	4.50
CB	GMVA-TC	103	12.00	.86	4.80
CB	GMVC	103	12.00	.86	4.80
CB	GMVG	103	12.00	.86	4.80
CB	GMVH	103	12.00	.86	4.80
CB	GMW-ALL	104	14.00	.44	5.30
CB	GMWA	105	8.00	.51	5.00
CB	GMWC	106	17.00	.75	5.50
CB	GMWH	107	15.20	.97	4.20
CB	V-250	107	15.20	.97	4.20
CB	V-330	107	15.20	.97	4.20
CB	W-330	107	15.20	.97	4.20
CB	Z-330	107	15.20	.97	4.20
CB	LS	108	9.30	2.71	3.80
CB	LSV	108	9.30	2.71	3.80
CB	OTHER	109	12.00	1.00	3.50
CL	BA	201	9.90	1.94	5.90
CL	BA-HC	201	9.90	1.94	5.90
CL	HBA	201	9.90	1.94	5.90
CL	HLA	201	9.90	1.94	5.90
CL	BA-T	202	4.70	2.23	8.30
CL	HBA-T	202	4.70	2.23	8.30
CL	HLA-T	203	7.60	2.29	5.10
CL	HRA-T	203	7.60	2.29	5.10
CL	HRSA-T	203	7.60	2.29	5.10
CL	TCV	204	6.60	2.18	4.70
CL	TCVA	204	6.60	2.18	4.70
CL	TCVC	205	10.20	3.58	5.00
CL	TCVD	205	10.20	3.58	5.00
CL	TLA-ALL	206	8.50	2.40	5.40
CL	TRA	206	8.50	2.40	5.40
IR	KVG	301	13.30	.62	1.30
IR	KVGA	301	13.30	.62	1.30
IR	KVGB	301	13.30	.62	1.30
IR	KVR	302	10.80	.90	2.20
IR	KVS	303	14.80	.68	2.80
IR	KVSR	303	14.80	.68	2.80
IR	KVT	304	7.50	1.04	2.80
WO	ALL	400	12.00	1.00	3.50
WI	ALL	500	12.00	1.00	3.50
DL	ALL	600	12.00	1.00	3.50
WA	ALL	700	12.00	1.00	3.50
XX	OTHER	800	12.00	1.00	3.50

TABLE A-2. GAS TURBINE BRAKE SPECIFIC EMISSION FACTORS USED IN THIS PROJECT

MFG.	MODEL NUMBER	MODEL CODE	ESTIMATED EMISSION FACTORS AT RATED HORSEPOWER, GRAMS/BHP-HR NOX	CO	HC
GE	FRAME 3	1101	1.53	.10	.04
GE	3000-SC	1102	1.10	.20	.04
GE	3000-RC	1103	1.71	.06	.04
GE	5000-XX	1104	1.30	.10	.04
GE	LM 1500	1105	1.40	.48	.04
GE	LM 2500	1106	1.48	.29	.04
PW	GG12A	1201	1.20	1.00	.17
PW	GG3C-1	1202	1.30	.84	.19
PW	GG3C-4	1203	1.16	1.17	.15
PW	GG4A-2	1204	1.38	.80	.14
SO	SATURN	1301	.78	.68	.17
SO	CENTAUR	1302	1.19	.75	.17
XX	OTHER	1401	1.40	.40	.04

TABLE B-1. 1973 EMISSIONS FROM PISTON ENGINES OVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS BY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES

STATE	INSTALLED HORSEPOWER	BHP-HRS OPERATED	EMISSIONS, TONS/YEAR NOX	CO	HC
ALABAMA	190400	1221391018	16935	1403	5993
ARIZONA	153860	1037235898	12435	1594	5078
ARKANSAS	139600	785052288	11406	766	3368
CALIFORNIA	97680	542992723	5739	1054	2918
COLORADO	20760	90352426	1047	135	505
CONNECTICUT	12000	326400	3	0	2
DELAWARE	0	0	0	0	0
FLORIDA	69980	515000064	5917	978	2059
GEORGIA	116050	728815018	7941	1191	4499
IDAHO	0	0	0	0	0
ILLINOIS	291941	1578501216	18891	2523	7552
INDIANA	263183	1492888641	17855	2844	7137
IOWA	199210	1276614605	14335	1968	5694
KANSAS	796734	5310720077	67705	6360	22183
KENTUCKY	361023	2436485554	29083	3836	12535
LOUISIANA	683331	4204894338	47023	7359	20565
MAINE	0	0	0	0	0
MARYLAND	40250	241178400	1588	596	1660
MASSACHUSETTS	0	0	0	0	0
MICHIGAN	283920	1081448419	13326	1835	5309
MINNESOTA	57500	409200960	2871	980	2117
MISSISSIPPI	614181	3939350066	47953	6309	20043
MISSOURI	131060	861552029	11813	928	3965
MONTANA	0	0	0	0	0
NEBRASKA	123290	761865610	9297	850	2977
NEVADA	0	0	0	0	0
NEW HAMPSHIRE	0	0	0	0	0
NEW JERSEY	26550	52166592	822	39	162
NEW MEXICO	293677	1841947050	24355	2460	8441
NEW YORK	88900	296672064	3644	395	1201
NORTH CAROLINA	102460	717173549	5644	1666	4202
NORTH DAKOTA	0	0	0	0	0
OHIO	195753	1099811300	14683	1376	4713
OKLAHOMA	242188	1524257948	17936	2205	7360
OREGON	0	0	0	0	0
PENNSYLVANIA	363750	1474439242	19316	1936	6444
RHODE ISLAND	8100	18144	0	0	0
SOUTH CAROLINA	41000	290070720	4195	217	1571
SOUTH DAKOTA	0	0	0	0	0
TENNESSEE	316194	2135112156	26039	3506	11217
TEXAS	939648	5308530152	69485	5799	23670
UTAH	7400	60595392	545	160	361
VERMONT	0	0	0	0	0
VIRGINIA	126600	606688992	6594	1114	3375
WASHINGTON	0	0	0	0	0
WEST VIRGINIA	217490	1046957203	13316	1580	4653
WISCONSIN	15000	106577280	1300	80	448
WYOMING	32300	229210848	2314	652	1381
48 STATES	7662963	45306094379	553353	66700	215357

TABLE B-2. 1973 EMISSIONS FROM GAS TURBINES OVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS BY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES

STATE	INSTALLED HORSEPOWER	BHP-HRS OPERATED	EMISSIONS, TONS/YEAR NOX	CO	HC
ALABAMA	102080	484457702	766	70	23
ARIZONA	128846	840843759	1380	100	40
ARKANSAS	0	0	0	0	0
CALIFORNIA	19300	105045792	174	13	5
COLORADO	0	0	0	0	0
CONNECTICUT	0	0	0	0	0
DELAWARE	0	0	0	0	0
FLORIDA	3300	752928	1	1	0
GEORGIA	0	0	0	0	0
IDAHO	0	0	0	0	0
ILLINOIS	14200	30071040	45	14	1
INDIANA	12750	70275840	128	7	3
IOWA	82330	351063360	462	396	53
KANSAS	264345	1541876270	2352	828	130
KENTUCKY	222100	1409722080	2077	868	164
LOUISIANA	582065	3136239024	4987	1043	218
MAINE	0	0	0	0	0
MARYLAND	0	0	0	0	0
MASSACHUSETTS	9665	24368270	29	15	3
MICHIGAN	263310	1316668896	1964	627	76
MINNESOTA	135400	988296192	1522	429	47
MISSISSIPPI	349830	1797380333	2963	656	154
MISSOURI	0	0	0	0	0
MONTANA	0	0	0	0	0
NEBRASKA	54700	306136320	481	188	27
NEVADA	0	0	0	0	0
NEW HAMPSHIRE	0	0	0	0	0
NEW JERSEY	5000	715200	1	1	0
NEW MEXICO	194610	1444283002	2232	219	78
NEW YORK	4910	5439341	7	5	1
NORTH CAROLINA	0	0	0	0	0
NORTH DAKOTA	0	0	0	0	0
OHIO	32600	160471872	261	23	9
OKLAHOMA	45365	246126461	390	70	19
OREGON	0	0	0	0	0
PENNSYLVANIA	283670	602913274	861	278	44
RHODE ISLAND	0	0	0	0	0
SOUTH CAROLINA	0	0	0	0	0
SOUTH DAKOTA	0	0	0	0	0
TENNESSEE	136200	933495360	1497	457	92
TEXAS	235367	1370734980	2146	304	92
UTAH	0	0	0	0	0
VERMONT	0	0	0	0	0
VIRGINIA	8800	7428960	6	6	2
WASHINGTON	0	0	0	0	0
WEST VIRGINIA	86015	382981027	617	129	26
WISCONSIN	45600	293409360	414	154	21
WYOMING	9550	47755872	61	43	10
48 STATES	3331908	17898952516	27823	6944	1339

TABLE B-3. 1973 EMISSIONS FROM PISTON & GAS TURBINE ENGINES OVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS BY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES

STATE	INSTALLED HORSEPOWER	BHP-HRS OPERATED	EMISSIONS, TONS/YEAR NOX	CO	HC
ALABAMA	292480	1705848720	17700	1473	6016
ARIZONA	282706	1878079657	13815	1694	5118
ARKANSAS	139600	785052288	11406	766	3368
CALIFORNIA	116980	648038515	5912	1067	2923
COLORADO	20760	90352426	1047	135	505
CONNECTICUT	12000	326400	3	0	2
DELAWARE	0	0	0	0	0
FLORIDA	73280	515752992	5918	979	2059
GEORGIA	116050	728815018	7941	1191	4499
IDAHO	0	0	0	0	0
ILLINOIS	306141	1608572256	18937	2538	7553
INDIANA	275933	1563164481	17983	2851	7140
IOWA	281540	1627677965	14797	2364	5747
KANSAS	1061079	6852596347	70057	7188	22313
KENTUCKY	583123	3846207634	31160	4704	12699
LOUISIANA	1265396	7341133362	52010	8402	20783
MAINE	0	0	0	0	0
MARYLAND	40250	241178400	1588	596	1660
MASSACHUSETTS	9665	24368270	29	15	3
MICHIGAN	547230	2398117315	15290	2461	5385
MINNESOTA	192900	1397497152	4393	1409	2164
MISSISSIPPI	964011	5736730399	50915	6966	20196
MISSOURI	131060	861552029	11813	928	3965
MONTANA	0	0	0	0	0
NEBRASKA	177990	1068001930	9778	1037	3004
NEVADA	0	0	0	0	0
NEW HAMPSHIRE	0	0	0	0	0
NEW JERSEY	31550	52881792	823	40	162
NEW MEXICO	488287	3286230052	26587	2680	8519
NEW YORK	93810	302111405	3651	400	1202
NORTH CAROLINA	102460	717173549	5644	1666	4202
NORTH DAKOTA	0	0	0	0	0
OHIO	228353	1260283172	14944	1399	4722
OKLAHOMA	287553	1770384409	18326	2276	7379
OREGON	0	0	0	0	0
PENNSYLVANIA	647420	2077352515	20177	2215	6488
RHODE ISLAND	8100	18144	0	0	0
SOUTH CAROLINA	41000	290070720	4195	217	1571
SOUTH DAKOTA	0	0	0	0	0
TENNESSEE	452394	3068607516	27537	3963	11310
TEXAS	1175015	6679265132	71631	6103	23762
UTAH	7400	60595392	545	160	361
VERMONT	0	0	0	0	0
VIRGINIA	135400	614117952	6601	1120	3376
WASHINGTON	0	0	0	0	0
WEST VIRGINIA	303505	1429938230	13934	1710	4679
WISCONSIN	60600	399986640	1715	234	469
WYOMING	41850	276966720	2375	695	1391
48 STATES	10994871	63205046894	581175	73644	216696

TABLE B-4. 1972 EMISSIONS FROM PISTON ENGINES OVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS BY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES

STATE	INSTALLED HORSEPOWER	BHP-HRS OPERATED	EMISSIONS, TONS/YEAR NOX	CO	HC
ALABAMA	190400	1276601222	17455	1493	6294
ARIZONA	153860	1125873466	13452	1765	5544
ARKANSAS	139600	814139760	11784	804	3466
CALIFORNIA	97680	560648909	5858	1114	3067
COLORADO	20760	106799194	1224	166	613
CONNECTICUT	12000	1920000	16	1	11
DELAWARE	0	0	0	0	0
FLORIDA	69980	536990957	6179	1014	2146
GEORGIA	116050	776900045	8483	1262	4815
IDAHO	0	0	0	0	0
ILLINOIS	279941	1809382912	21588	3031	8744
INDIANA	249683	1569529073	18621	2953	7516
IOWA	199210	1370934691	15591	2065	6028
KANSAS	789030	5311004321	67604	6373	22136
KENTUCKY	361023	2472433996	29484	3930	12701
LOUISIANA	683331	4336573905	48763	7550	21228
MAINE	0	0	0	0	0
MARYLAND	40250	235369296	1551	582	1627
MASSACHUSETTS	0	0	0	0	0
MICHIGAN	268920	1162196390	14392	1856	5619
MINNESOTA	57500	401415360	2933	935	2050
MISSISSIPPI	624581	4310064420	51940	7149	22044
MISSOURI	131060	862403952	11831	928	3963
MONTANA	0	0	0	0	0
NEBRASKA	123290	811345306	9894	911	3176
NEVADA	0	0	0	0	0
NEW HAMPSHIRE	0	0	0	0	0
NEW JERSEY	26550	50413680	785	39	159
NEW MEXICO	253677	1808208004	23847	2427	8318
NEW YORK	88900	319352256	3986	424	1303
NORTH CAROLINA	102460	734036803	5792	1700	4304
NORTH DAKOTA	0	0	0	0	0
OHIO	195753	1122209620	14934	1401	4806
OKLAHOMA	242188	1572042626	18481	2180	7545
OREGON	0	0	0	0	0
PENNSYLVANIA	351050	1526033702	20160	1960	6681
RHODE ISLAND	8100	482112	4	1	3
SOUTH CAROLINA	41000	309842880	4506	230	1683
SOUTH DAKOTA	0	0	0	0	0
TENNESSEE	316194	2298345886	28041	3766	12068
TEXAS	927548	5583577874	73709	6040	24871
UTAH	7400	60595392	545	160	361
VERMONT	0	0	0	0	0
VIRGINIA	126600	657991776	7377	1154	3541
WASHINGTON	0	0	0	0	0
WEST VIRGINIA	217490	1096581677	13970	1659	4905
WISCONSIN	15000	101977440	1255	76	426
WYOMING	16700	89996064	915	314	510
48 STATES	7544759	47184214966	576951	69416	224271

TABLE B-5. 1972 EMISSIONS FROM GAS TURBINES
OVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS
BY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES

STATE	INSTALLED HORSEPOWER	BHP-HRS OPERATED	EMISSIONS, TONS/YEAR NOX	CO	HC
ALABAMA	102080	505193760	802	72	24
ARIZONA	128846	930501901	1522	111	44
ARKANSAS	0	0	0	0	0
CALIFORNIA	19300	124236480	205	15	6
COLORADO	0	0	0	0	0
CONNECTICUT	0	0	0	0	0
DELAWARE	0	0	0	0	0
FLORIDA	3300	966240	1	1	0
GEORGIA	0	0	0	0	0
IDAHO	0	0	0	0	0
ILLINOIS	14200	55300080	84	26	3
INDIANA	12750	77846160	140	11	4
IOWA	82330	407001120	525	495	66
KANSAS	260845	1788829517	2672	1151	170
KENTUCKY	222100	1620268320	2403	932	179
LOUISIANA	562065	3311429232	5236	1140	236
MAINE	0	0	0	0	0
MARYLAND	0	0	0	0	0
MASSACHUSETTS	9665	27604930	31	18	4
MICHIGAN	263310	1237608619	1840	572	71
MINNESOTA	135400	998347488	1536	436	48
MISSISSIPPI	349830	2148915312	3500	787	178
MISSOURI	0	0	0	0	0
MONTANA	0	0	0	0	0
NEBRASKA	54700	368378880	559	274	38
NEVADA	0	0	0	0	0
NEW HAMPSHIRE	0	0	0	0	0
NEW JERSEY	5000	1665600	2	2	0
NEW MEXICO	194610	1412460163	2189	196	73
NEW YORK	4910	4126310	5	4	1
NORTH CAROLINA	0	0	0	0	0
NORTH DAKOTA	0	0	0	0	0
OHIO	32600	241850400	396	32	12
OKLAHOMA	38765	231364934	369	58	16
OREGON	0	0	0	0	0
PENNSYLVANIA	283670	893717952	1272	334	61
RHODE ISLAND	0	0	0	0	0
SOUTH CAROLINA	0	0	0	0	0
SOUTH DAKOTA	0	0	0	0	0
TENNESSEE	136200	991243968	1587	463	96
TEXAS	235367	1327164200	2127	278	86
UTAH	0	0	0	0	0
VERMONT	0	0	0	0	0
VIRGINIA	8800	7864032	7	6	2
WASHINGTON	0	0	0	0	0
WEST VIRGINIA	86015	359999549	573	129	24
WISCONSIN	44500	320457168	452	169	23
WYOMING	6000	40006080	51	36	8
48 STATES	3297158	19434348396	30087	7748	1473

TABLE B-6. 1972 EMISSIONS FROM PISTON & GAS TURBINE ENGINES OVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS BY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES

STATE	INSTALLED HORSEPOWER	BHP-HRS OPERATED	EMISSIONS, TONS/YEAR NOX	CO	HC
ALABAMA	292480	1781794982	18258	1566	6319
ARIZONA	282706	2056375367	14974	1875	5588
ARKANSAS	139600	814139760	11784	804	3466
CALIFORNIA	116980	684885389	6063	1129	3073
COLORADO	20760	106799194	1224	166	613
CONNECTICUT	12000	1920000	16	1	11
DELAWARE	0	0	0	0	0
FLORIDA	73280	537957197	6180	1015	2146
GEORGIA	116050	776900045	8483	1262	4815
IDAHO	0	0	0	0	0
ILLINOIS	294141	1864682992	21672	3057	8746
INDIANA	262433	1647375233	18760	2963	7520
IOWA	281540	1777935811	16116	2559	6094
KANSAS	1049875	7099833838	70276	7524	22306
KENTUCKY	583123	4092702316	31887	4862	12880
LOUISIANA	1245396	7648003137	54000	8690	21464
MAINE	0	0	0	0	0
MARYLAND	40250	235369296	1551	582	1627
MASSACHUSETTS	9665	27604930	31	18	4
MICHIGAN	532230	2399805010	16233	2428	5690
MINNESOTA	192900	1399762848	4469	1371	2097
MISSISSIPPI	974411	6458979732	55440	7936	22222
MISSOURI	131060	862403952	11831	928	3963
MONTANA	0	0	0	0	0
NEBRASKA	177990	1179724186	10453	1186	3213
NEVADA	0	0	0	0	0
NEW HAMPSHIRE	0	0	0	0	0
NEW JERSEY	31550	52079280	788	41	159
NEW MEXICO	448287	3220668167	26036	2623	8390
NEW YORK	93810	323478566	3991	428	1304
NORTH CAROLINA	102460	734036803	5792	1700	4304
NORTH DAKOTA	0	0	0	0	0
OHIO	228353	1364060020	15329	1434	4818
OKLAHOMA	280953	1803407560	18850	2238	7561
OREGON	0	0	0	0	0
PENNSYLVANIA	634720	2419751654	21432	2294	6743
RHODE ISLAND	8100	482112	4	1	3
SOUTH CAROLINA	41000	309842880	4506	230	1683
SOUTH DAKOTA	0	0	0	0	0
TENNESSEE	452394	3289589854	29628	4229	12165
TEXAS	1162915	6910742074	75836	6318	24957
UTAH	7400	60595392	545	160	361
VERMONT	0	0	0	0	0
VIRGINIA	135400	665855808	7384	1161	3543
WASHINGTON	0	0	0	0	0
WEST VIRGINIA	303505	1456581226	14543	1788	4929
WISCONSIN	59500	422434608	1707	245	448
WYOMING	22700	130002144	967	350	518
48 STATES	10841917	66618563362	607038	77164	225744

APPENDIX C

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              PROGRAM EMITAG(INPUT,OUTPUT,TAPE5=INPUT)
        C
        C     PROGRAM FORMS EMISSION TABLES FOR ENGINES
        C      USED IN NATURAL GAS TRANSMISSION
        C
        C     PROJECT 11-3438-002   CHARLES URBAN  X-2644
        C
000003        DIMENSION TBL(48,5,5),ISTAB(2,48),IST(48),ICARD(8),IHG(3,3)
000003        DIMENSION MOD(100),ANOX(100),ACO(100),AHC(100),ISTA(48),ISTB(48)
000003        DIMENSION TOTAL(5)
000003        EQUIVALENCE (ISTAB(1),ISTA(1)),(ISTAB(49),ISTB(1))
000003        DATA IST  /10HAL          ,10HAZ          ,10HAR          ,10HCA
             1          ,10HCO          ,10HCT          ,10HDE          ,10HFL
             2          ,10HGA          ,10HID          ,10HIL          ,10HIN
             3          ,10HIA          ,10HKS          ,10HKY          ,10HLA
             4          ,10HME          ,10HMD          ,10HMA          ,10HMI
             5          ,10HMN          ,10HMS          ,10HMO          ,10HMT
             6          ,10HNE          ,10HNV          ,10HNH          ,10HNJ
             7          ,10HNM          ,10HNY          ,10HNC          ,10HND
             8          ,10HOH          ,10HOK          ,10HOR          ,10HPA
             9          ,10HRI          ,10HSC          ,10HSD          ,10HTN
             *          ,10HTX          ,10HUT          ,10HVT          ,10HVA
             1          ,10HWA          ,10HWV          ,10HWI          ,10HWY
             2          /
000003        DATA ISTA /10HALABAMA   ,10H          ,10HARIZONA   ,10H
             1          ,10HARKANSAS  ,10H          ,10HCALIFORNIA,10H
             2          ,10HCOLORADO  ,10H          ,10HCONNECTICU,10HT
             3          ,10HDELAWARE  ,10H          ,10HFLORIDA   ,10H
             4          ,10HGEORGIA   ,10H          ,10HIDAHO     ,10H
             5          ,10HILLINOIS  ,10H          ,10HINDIANA   ,10H
             6          ,10HIOWA      ,10H          ,10HKANSAS    ,10H
             7          ,10HKENTUCKY  ,10H          ,10HLOUISIANA ,10H
             8          ,10HMAINE     ,10H          ,10HMARYLAND  ,10H
             9          ,10HMASSACHUSE,10HTTS       ,10HMICHIGAN  ,10H
             *          ,10HMINNESOTA ,10H          ,10HMISSISSIPP,10HI
             1          ,10HMISSOURI  ,10H          ,10HMONTANA   ,10H
             2          /
000003        DATA ISTB /10HNEBRASKA  ,10H          ,10HNEVADA    ,10H
             1          ,10HNEW HAMPSH,10HIRE       ,10HNEW JERSEY,10H
             2          ,10HNEW MEXICO,10H          ,10HNEW YORK  ,10H
             3          ,10HNORTH CARO,10HLINA      ,10HNORTH DAKO,10HTA
             4          ,10HOHIO      ,10H          ,10HOKLAHOMA  ,10H
             5          ,10HOREGON    ,10H          ,10HPENNSYLVAN,10HIA
             6          ,10HRHODE ISLA,10HND        ,10HSOUTH CARO,10HLINA
             7          ,10HSOUTH DAKO,10HTA        ,10HTENNESSEE ,10H
             8          ,10HTEXAS     ,10H          ,10HUTAH      ,10H
             9          ,10HVERMONT   ,10H          ,10HVIRGINIA  ,10H
             *          ,10HWASHINGTON,10H          ,10HWEST VIRGI,10HNIA
             1          ,10HWISCONSIN ,10H          ,10HWYOMING   ,10H
             2          /
000003        DATA ICARD/10H.  PISTON ,10HENGINE BRA,10HKE SPECIFI,10HC EMISSION
             1          ,10H.  GAS TUR,10HBINE BRAKE,10H SPECIFIC ,10HEMISSION
             2          /
000003        DATA IHG  /10H PISTON EN,10HGINES     ,10H          ,10H GAS TURBI
             1          ,10HNES       ,10H          ,10H PISTON & ,10HGAS TURBIN
             2          ,10HE ENGINES /
000003        DATA IBLK /10H          /
```

```
000003          DATA I48US/10H48 STATES /
000003          DO 100 K=1,5
000005          DO 100 J=1,5
000006          DO 100 I=1,48
000007          TBL(I,J,K)=0.0
000015      100 CONTINUE
000023          CONV=1.0/(453.6*2000.)
000025          PRINT 1100,(ICARD(I),I=1,4)
000036     1100 FORMAT(1H1,15X,6HTABLE ,2X,4A10 /
             1          27X,28HFACTORS USED IN THIS PROJECT ///
             2          37X,29HESTIMATED EMISSION FACTORS AT /
             3          17X,2(5HMODEL,5X),30HRATED HORSEPOWER, GRAMS/BHP-HR /
             4          10X,4HMFG.,3X,6HNUMBER,4X,4HCODE,10X,3HNOX,7X,2HCO,7X,2HHC
             5          / )
000036          CNOX=0.96
000040          CCO=1.00
000041          CHC=1.00
000042          I000=1000
000043          MODS=57
000044          DO 150 MO=1,MODS
000045          READ 1000,MFG,MODNO,MOD(MO),ANOX(MO),ACO(MO),AHC(MO)
000064     1000 FORMAT(1X,A2,4X,A7,4X,I4,4X,3(4X,F5.2))
000064          IF(MOD(MO) .LT. I000) GO TO 120
000067          NOR=MO-1
000071          I000=2000
000072          PRINT 1100,(ICARD(I),I=5,8)
000103          CNOX=0.98
000105          CCO=1.08
000106          CHC=1.08
000110      120 CONTINUE
000110          PRINT 1110,MFG,MODNO,MOD(MO),ANOX(MO),ACO(MO),AHC(MO)
000130     1110 FORMAT(11X,A2,4X,A7,4X,I4,4X,3(4X,F5.2))
000130          ANOX(MO)=CNOX*ANOX(MO)
000133          ACO(MO)=CCO*ACO(MO)
000135          AHC(MO)=CHC*AHC(MO)
000137      150 CONTINUE
000141          PRINT 1120
000144     1120 FORMAT(1H1,12H E R R A T A / )
000144          IS=1
000145          GO TO 200
000146      190 PRINT 1130,(ICARD(I),I=1,8)
000160     1130 FORMAT(1X,8A10)
000160      200 CONTINUE
000160          READ 1010,(ICARD(I),I=1,8)
000172     1010 FORMAT(8A10)
000172          IF(EOF,5) 300,210
000175      210 CONTINUE
000175          DECODE(78,1020,ICARD) ICO,ISTAT,IDI
000211     1020 FORMAT(A4,26X,A2,42X,I4)
000211          IF(ICO .EQ. IBLK) GO TO 250
000213          ISTATE=ISTAT
000215          IDD=IDI
000216          IF(IST(IS) .EQ. ISTATE) GO TO 200
000221          DO 220 I=1,48
000222          IS=I
000223          IF(IST(IS) .EQ. ISTATE) GO TO 200
000226      220 CONTINUE
000227          GO TO 190
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000230      250 CONTINUE
000230          DECODE(69,1030,ICARD) IRT,HP,MODEL,ENGS2,HRS2,ENGS3,HRS3
000254     1030 FORMAT(4X,A1,15X,F5.0,8X,I4,12X,2(1X,F2.0,1X,F6.0))
000254          IF(IDI .NE. IDD) GO TO 190
000256          IF(HP .LE. 0.0 .OR. HP .GT. 30000.) GO TO 190
000267          IF(HRS2 .GT. 8784.*ENGS2) GO TO 190
000273          IF(HRS3 .GT. 8784.*ENGS3) GO TO 190
000277          ITYP=3
000300          IF(IRT .EQ. 1HR) ITYP=0
000303          IF(IRT .EQ. 1HT) ITYP=1
000306          IF(ITYP .EQ. 3) GO TO 190
000310          IM1=1+ITYP*NOR
000314          IM2=NOR+ITYP*(MODS-NOR)
000317          DO 260 I=IM1,IM2
000321          IM=I
000322          IF(MOD(I) .EQ. MODEL) GO TO 270
000324      260 CONTINUE
000326          GO TO 190
000327      270 CONTINUE
000327          IT=ITYP+1
000331          TBL(IS,IT,1)=TBL(IS,IT,1)+ENGS3*HP
000337          HPHR3=0.96*HP*HRS3
000341          TBL(IS,IT,2)=TBL(IS,IT,2)+HPHR3
000345          TBL(IS,IT,3)=TBL(IS,IT,3)+CONV*ANOX(IM)*HPHR3
000353          TBL(IS,IT,4)=TBL(IS,IT,4)+CONV*ACO(IM)*HPHR3
000362          TBL(IS,IT,5)=TBL(IS,IT,5)+CONV*AHC(IM)*HPHR3
000371          IT=ITYP+4
000373          TBL(IS,IT,1)=TBL(IS,IT,1)+ENGS2*HP
000401          HPHR2=0.96*HP*HRS2
000403          TBL(IS,IT,2)=TBL(IS,IT,2)+HPHR2
000407          TBL(IS,IT,3)=TBL(IS,IT,3)+CONV*ANOX(IM)*HPHR2
000415          TBL(IS,IT,4)=TBL(IS,IT,4)+CONV*ACO(IM)*HPHR2
000424          TBL(IS,IT,5)=TBL(IS,IT,5)+CONV*AHC(IM)*HPHR2
000433          GO TO 200
000434      300 CONTINUE
000434          ITAB=0
000435          IYR=1973
000436          DO 390 IY=1,2
000440          DO 310 J=1,5
000441          DO 310 I=1,48
000442          TBL(I,3,J)=0.0
000446      310 CONTINUE
000452          DO 360 IT=1,3
000453          ITAB=ITAB+1
000455          DO 320 I=1,5
000456          TOTAL(I)=0.0
000457      320 CONTINUE
000461          PRINT 1140,ITAB,IYR,(IHG(I,IT),I=1,3)
000477     1140 FORMAT(1H1,13X,5HTABLE,I3,1H.,I6,15H EMISSIONS FROM,3A10 /
               1        25X,48HOVER 1000 HP USED FOR COMPRESSION OF NATURAL GAS /
               2        25X,44HBY AGA-PRC MEMBER COMPANIES AND SUBSIDIARIES //
               3        25X,9HINSTALLED,5X,7HBHP-HRS,7X,20HEMISSIONS, TONS/YEAR /
               4        10X,5HSTATE,10X,22HHORSEPOWER    OPERATED,7X,3HNOX,6X,2HCO,
               5        6X,2HHC  /  10X,65(1H-) )
000477          DO 340 IS=1,48
000501          PRINT 1150,(ISTAB(I,IS),I=1,2),(TBL(IS,IT,J),J=1,5)
000525     1150 FORMAT(10X,A10,A4,F10.0,F15.0,F10.0,2F8.0)
000525          DO 330 I=1,5
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000527           TOTAL(I)=TOTAL(I)+TBL(IS,IT,I)
000535           TBL(IS,3,I)=TBL(IS,3,I)+TBL(IS,IT,I)
000545       330 CONTINUE
000547       340 CONTINUE
000551           PRINT 1160
000554      1160 FORMAT(26X,8(1H-),3X,12(1H-),3X,7(1H-),2(2X,6H------) )
000554           PRINT 1150,I48US,IBLK,(TOTAL(I),I=1,5)
000572       360 CONTINUE
000574           DO 380 J=1,5
000576           DO 380 I=1,48
000577           TBL(I,1,J)=TBL(I,4,J)
000604           TBL(I,2,J)=TBL(I,5,J)
000607       380 CONTINUE
000612           IYR=1972
000613       390 CONTINUE
000615           END
```

APPENDIX D - EGR EQUATION DERIVATION

In a gas turbine the majority of the air is introduced subsequent to the combustion area and therefore this secondary air has a minimal effect on the production of NO_x emissions. When using EGR with gas turbines, the portion of the EGR in the secondary air does not effectively reduce the production of NO_x emissions.

Therefore, an equation which can be used to estimate the effective EGR rate from the gross EGR rate has been approximated as follows:

(1) $$\%\ EGR_{(Effective)} = \%\ EGR_{(Gross)} \frac{(Air/Fuel)\ Stoichiometric}{(Air/Fuel)_{Gross}\ \left(1 - \frac{\%\ EGR_E}{100}\right)}$$

for $\%\ EGR_G \quad 100\ (1-(A/F)_S)$ and $A/F_G \quad A/F_S\ \left(1 + \frac{\%\ EGR_E}{100}\right)$

$\%\ EGR_E$ - portion of EGR as percent of intake air that is assumed to affect production of NO_x

$\%\ EGR_G$ - portion of total exhaust recirculated

A/F_S - Stoichiometer ratio for fuel used

A/F_G - Actual overall ratio for the gas turbine

by rearranging equation (1) and solving for $\%EGR_E$ using the quadratic equation one obtains:

(2) $$\%\ EGR_E = 50 - \sqrt{2500 - 100\ \frac{A/F_S}{A/F_G}\ (\%EGR_G)}$$

and by rearranging:

(3) $$\%\ EGR_G = \frac{100\ (\%EGR_E) - (\%EGR_E)^2}{100} \cdot \frac{A/F_G}{A/F_S}$$

This equation should only be used as a good approximation for estimating purposes since it is a general theoretical equation which assumes the effective air/fuel ratio within the combustion area is stoichiometric. There are many additional factors affecting the absolute relationship between the gross and effective EGR rates.

Note: Although these equations were developed for gas turbines, they are also reasonably applicable to two-cycle natural gas reciprocating engines.