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EXHAUST EMISSIONS FROM UNCONTROLLED VEHICLES AND RELATED EQUIPMENT USING INTERNAL COMBUSTION ENGINES:

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Prepared by

Charles T Hare and Karl J. Springer

Southwest Research Institute
San Antonio, Texas

Contract No. EHS 70-108

EPA Project Officer:

William Roger Oliver

Prepared for

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Office of Mobile Source Air Pollution Control
Emission Control Technology Division
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ABSTRACT

This report is Part 6 of the Final Report on Exhaust Emissions From Uncontrolled Vehicles and Related Equipment Using Internal Combustion Engines, Contract EHS 70-108. In contrast to the other phases of the subject contract, no measurements of emissions from the source under consideration (Gas Turbine Electric Utility Powerplants) were taken as part of the research project. The reasons for this departure from normal practice were that information on gas turbine emissions available in the literature was deemed sufficient (at least on the major emissions) and that the small test effort possible within the scope of the contract would hardly add anything worthwhile to that body of knowledge.

Emission measurements which are used in this report were mostly taken on-site where the generating units were located, although a few tests have been conducted under laboratory conditions. Groups which performed the actual emissions test work are referenced later; and they include manufacturers, private research organizations, and government agencies. Data are presented on turbines manufactured by General Electric, Turbo Power & Marine, and Westinghouse. Emissions data include NO, NO_2, and NO_x measured by a variety of techniques; a less substantial amount of CO and hydrocarbon data; either CO_2 or O_2 (occasionally both) for a given test; and scattered information on SO_x, particulate, visible smoke, and less important pollutants.

These emissions data are utilized together with information on the location and population of turbine electric utility powerplants to estimate national emissions impact, based on usage as reported to the Federal Power Commission. Where possible, type of fuel used (gas or liquid) will be taken into account, since fuel type has a pronounced effect on emissions.

FOREWORD

The project for which this report constitutes part of the end product was initiated jointly on June 29, 1970 by the Division of Motor Vehicle Research and Development and the Division of Air Quality and Emission Data, both divisions of the agency known as NAPCA. Currently, these offices are the Emission Characterization and Control Development Branch of MSAPC and the National Air Data Branch of OAQPS, respectively, Office of Air and Water Programs, Environmental Protection Agency. The contract number is EHS 70-108, and the project is identified within Southwest Research Institute as 11-2869-001.

This report (Part 6) covers the gas turbine electric utility powerplant portion of the characterization work only, and the other items in the characterization work have been or will be covered by six other parts of the final report. In the order in which the final reports have been or will be submitted, the seven parts of the characterization work include: Locomotives and Marine Counterparts; Outboard Motors; Motorcycles; Small Utility Engines; Farm, Construction, and Industrial Engines; Gas Turbine Electric Utility Powerplants; and Snowmobiles. Other efforts which have been conducted as separate phases of Contract EHS 70-108 include: measurement of gaseous emissions from a number of aircraft turbine engines, measurement of crankcase drainage from a number of outboard motors, and investigation of emissions control technology for locomotive diesel engines; and those phases either have been or will be reported separately.

Cognizant technical personnel for the Environmental Protection Agency are currently Messrs. William Rogers Oliver and David S. Kircher; and past Project Officers include Messrs. J. L. Raney, A. J. Hoffman, B. D. McNutt, and G. J. Kennedy. Project Manager for Southwest Research Institute has been Mr. Karl J. Springer, and Mr. Charles T. Hare has carried the technical responsibility.

A great deal of the initial effort on gathering statistics for this report was expended by Mr. Charles M. Urban, senior research engineer at SwRI; and his contributions are sincerely appreciated.

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I. INTRODUCTION

The program of research on which this report is based was initiated by the Environmental Protection Agency to (1) characterize emissions from a broad range of internal combustion engines in order to accurately set priorities for future control, as required and (2) assist in developing more inclusive national and regional air pollution inventories. This document, which is Part 6 of what is planned to be a seven part final report, concerns emissions from gas turbine electric utility powerplants and the national impact of these emissions.

The emissions data presented in this report are from numerous sources, but no emissions tests as such were performed under the subject contract. This approach was taken to make the best possible use of both available funds and available data. The data-gathering operation was performed during the first several months of 1973, with the report activity scheduled subsequently as permitted by other work phases of the contract.

II. OBJECTIVES

The objectives of the gas turbine electric utility powerplant part of this project were to obtain emissions data and information on engine population and usage and to estimate emission factors and national impact on the basis of the data acquired. Insofar as available in the literature, it was intended to compile data on emissions of hydrocarbons, CO, NO_x (or NO or NO_2), SO_x, and CO_2 and/or O_2. Although it was recognized that only minimal amounts of data might be available, it was also intended to characterize aldehydes and particulate as well as possible.

Since the emissions measurements reported were not under the contractor's control, several types of measurement techniques were used. It was necessary in some cases to separate the measurements reported on the basis of technique and to eliminate those which did not appear credible.

III. PRESENTATION OF AVAILABLE DATA ON EMISSIONS

Data on emissions from gas turbines as used in electrical generation service comes from a number of sources[(1-13)*]; but unfortunately, there is little agreement among the sources on the terms in which the emissions are expressed. The efforts represented by this section of the report, then, include acquisition of the data and its conversion to uniform terms. This conversion often involved assumptions on engine air flow or fuel flow rates (based on manufacturers' data), since many sets of measurements were not complete. Another shortcoming of the available information was that relatively few data were obtained at loads below maximum rated (or base) load.

Calculation of mass emission rates was made on the basis of lb_m/hr, since this unit seemed to be most commonly used in the literature. The equations used to calculate mass rates from concentration data were quite standard for research work. In those cases in which exhaust rate data were available, the general equation used was:

$$lb_m X/hr = K_x \text{ (ppm X) (exhaust flow, } lb_m/hr)$$

When fuel rate data were available, the equation used was:

$$lb_m X/hr = C_x \text{ (ppm X) (fuel, } lb_m/hr)/TC$$

where TC = %CO + CO_2 + %HC as C, or TC $\cong$ %CO_2 for all conditions except idle. The last part of this statement means that very little HC and CO occur under load, and consequently that almost all the carbon in the exhaust appears as CO_2. Refer to Figures 3 and 4 for confirmation of these trends. The constants K_x and C_x are given in Table 1, noting that

TABLE 1. CONSTANTS USED FOR COMPUTATION OF MASS EMISSIONS

Constituent X	K_x	C_x Gas Fuel-$(CH_{3.8})_n$	C_x Oil Fuel-$(CH_2)_n$
NO_x	1.59×10^{-6}	2.90×10^{-4}	3.28×10^{-4}
HC-$(CH_{3.8})_n$	0.547×10^{-6}	1.00×10^{-4}	---------
HC-$(CH_3)_n$	0.519×10^{-6}	0.949×10^{-4}	---------
HC-$(CH_2)_n$	0.484×10^{-6}	----------	1.00×10^{-4}
CO	0.967×10^{-6}	1.77×10^{-4}	2.00×10^{-4}
SO_x	2.21×10^{-6}	4.04×10^{-4}	4.57×10^{-4}
Particulate, grains/SCF	1.87×10^{-3}	0.342	0.387

*Superscript numbers in parentheses refer to the List of References at the end of this report.

particulate concentrations are given in grains/standard cubic foot rather than ppm. The constants C_x are computed by the relationship:

$$C_x = \frac{100\ (\text{molecular wt. of X}) \times 10^{-6}}{\text{molecular wt. of fuel per carbon atom}}$$

and the constants K_x are computed by:

$$K_x = \frac{\text{molecular wt. of X}}{\text{molecular wt. of exhaust}} \times 10^{-6}$$

Since fuel/air ratios for turbines are quite low, the molecular weight of the exhaust was uniformly assumed to be that of air (28.97). The exhaust hydrocarbon compositions assumed for gas fuels were $(CH_{3.8})_n$ for "methane" or "unburned fuel" hydrocarbons and $(CH_3)_n$ if all the hydrocarbons were taken together in a single concentration value. Standard conditions were assumed to be 60° F (15.6° C) and 1 atmosphere.

Where emission rates were expressed on the basis of energy input, it was sometimes necessary to assume fuel heating values. The assumptions made were a gross heating value (HHV) of 19,700 BTU/lb_m and a net heating value (LHV) of 18,700 BTU/lb_m for liquid fuels and an HHV of about 22,000 BTU/lb_m for natural gas (a gas density of 0.047 lb_m/SCF was also assumed). In order to make an equitable evaluation of emissions from all the turbines on which data are available, it was decided to compute emissions in lb_m/megawatt hour as a function of percentage of rated load. Computing the specific emissions in this manner permits curves to be drawn which are as representative as possible of emissions from the most popular turbine models, and these curves are shown in Figures 1 through 5. The data used to generate Figures 1 through 5 are given in the Appendix. Table A-1 shows the data as obtained from the references, and Table A-2 lists the data after conversion to uniform units (lb_m/Mwh).

Figures 1 and 2 show typical NO_x emissions for commonly-used turbines, and these two figures could have been combined but with some penalty in legibility. It appears obvious that design differences between turbines do have some effect on NO_x emissions, but these differences are not so apparent for other exhaust constituents. Figures 3, 4, and 5 are composites of data available on all types of turbines used in electric utility service; and the reasons for combining data from different units are that (1) only a very few data were available on which to base each curve, and (2) no substantial differences were observed from one engine type to another. In addition to the data depicted by Figures 1 through 5, some information was acquired on emissions under zero load conditions which cannot, of course, be plotted in terms of mass per unit work output. These figures for the TP&M GG4-FT4 unit are 71.5 lb_m CO/hr and 24.6 lb_m HC/hr at low idle, and 165 lb_m CO/hr and 61.6 lb_m HC/hr at synchronous idle. For the G.E. MS5001-N unit at high idle (breaker open), CO emissions are 205

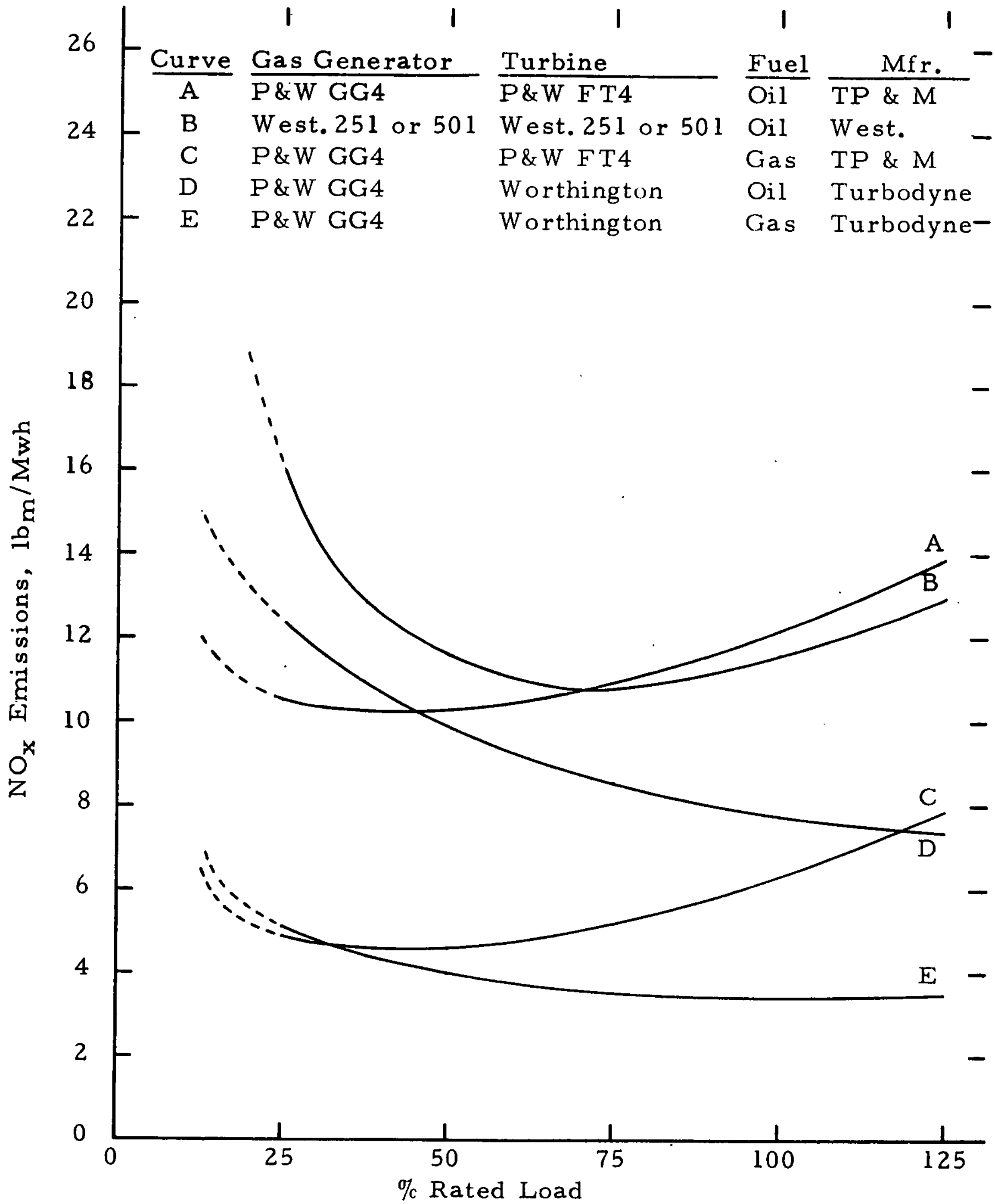

FIGURE 1. SPECIFIC EMISSIONS OF NO_x AS A FUNCTION OF LOAD FOR GAS TURBINE-POWERED GENERATORS MANUFACTURED BY WESTINGHOUSE, TURBODYNE, AND TURBO POWER & MARINE

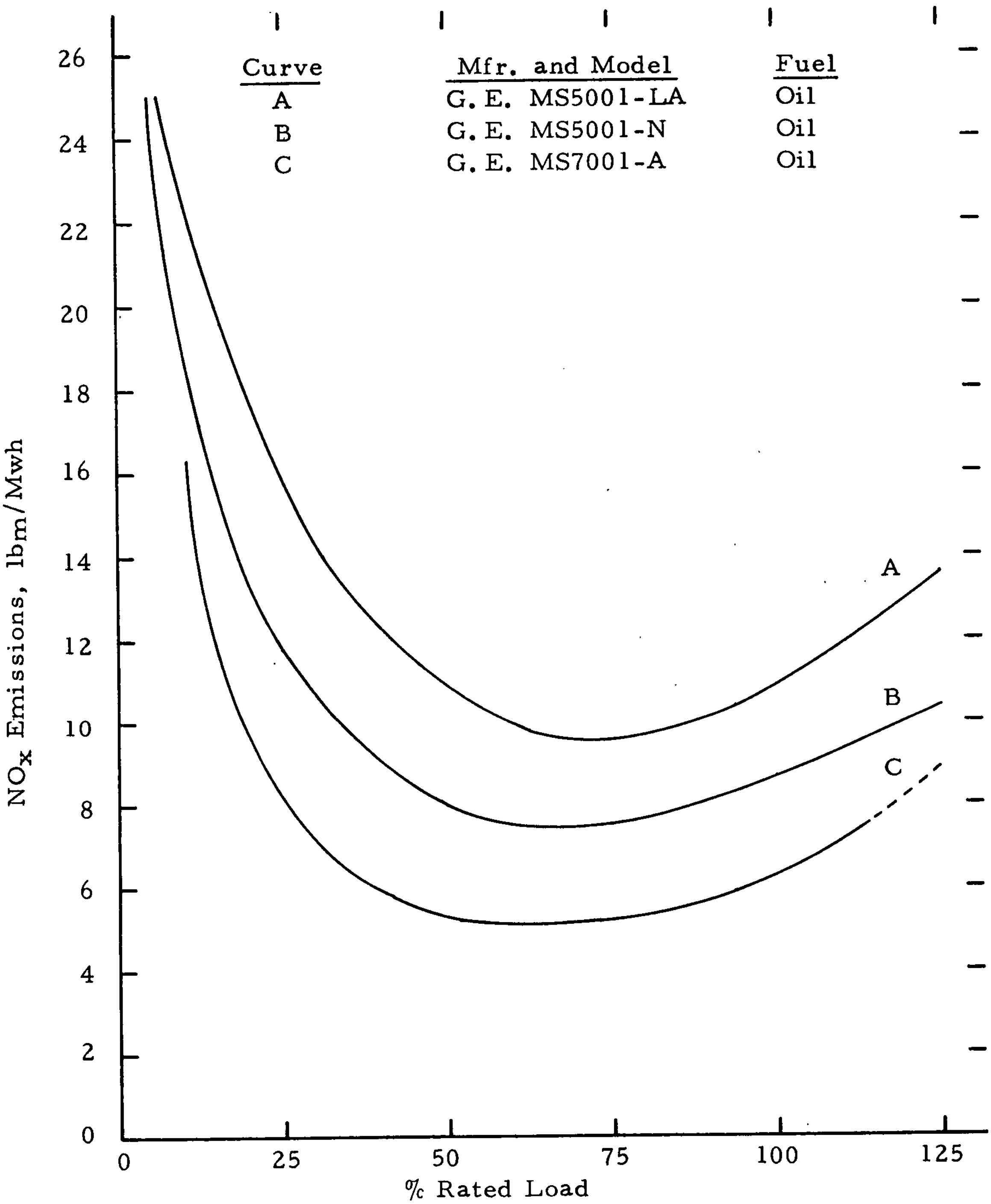

FIGURE 2. SPECIFIC EMISSIONS OF NO_x AS A FUNCTION OF LOAD FOR GAS TURBINE-POWERED GENERATORS MANUFACTURED BY GENERAL ELECTRIC

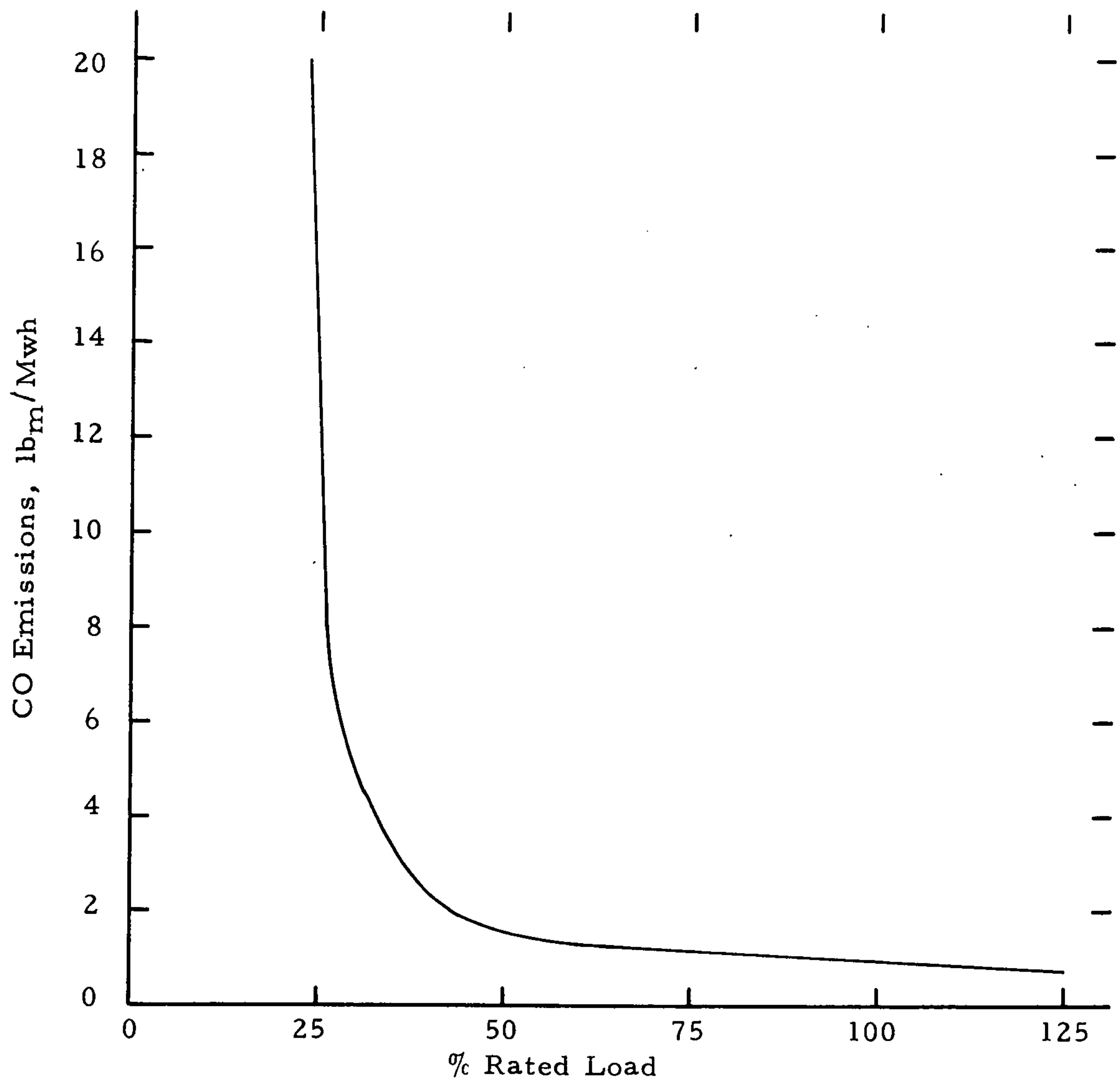

FIGURE 3. SPECIFIC EMISSIONS OF CO AS A FUNCTION OF LOAD FOR GAS TURBINE-POWERED GENERATORS, COMPOSITE OF SEVERAL MAKES AND MODELS

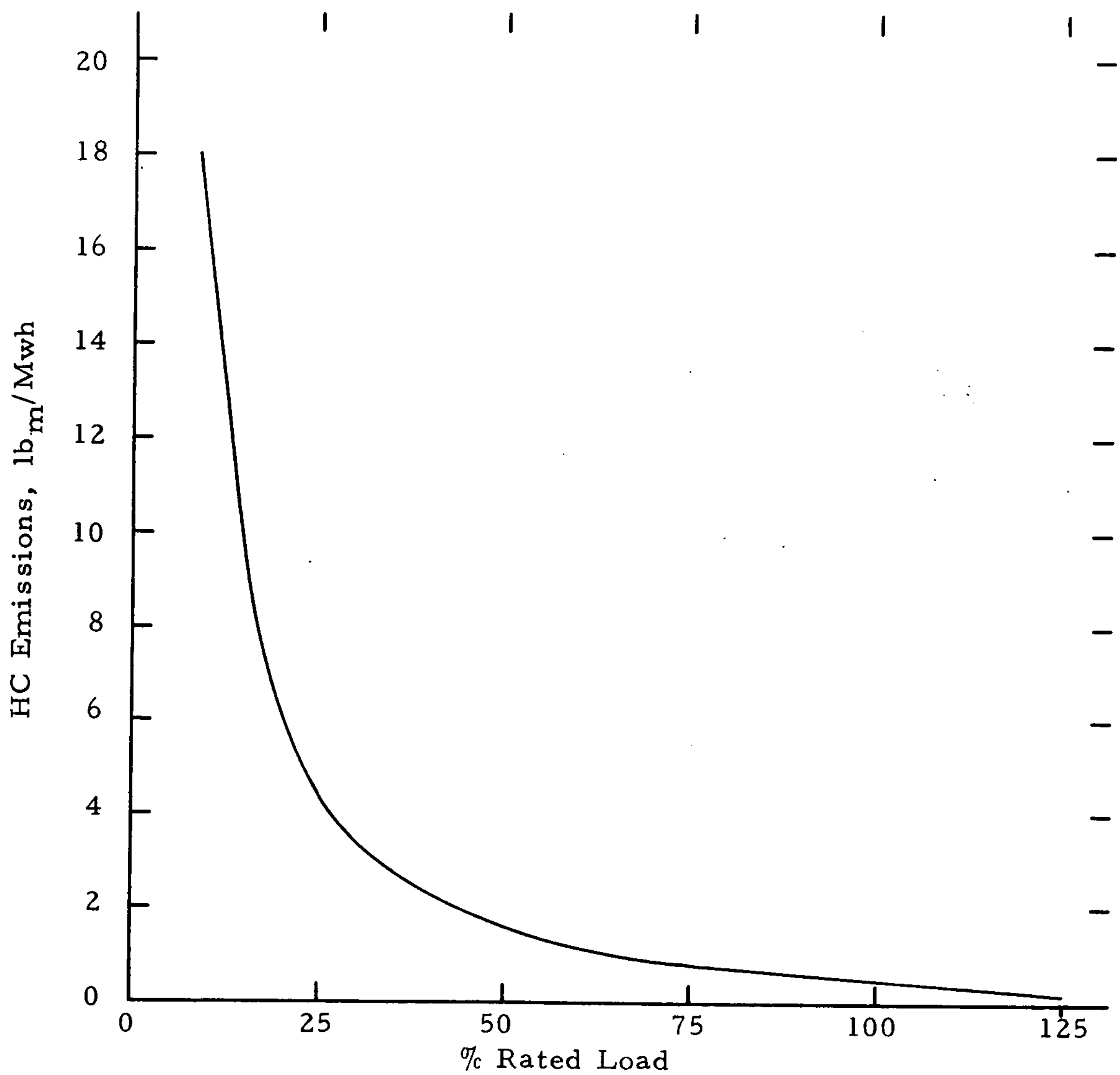

FIGURE 4. SPECIFIC EMISSIONS OF HYDROCARBONS AS A FUNCTION OF LOAD FOR GAS TURBINE-POWERED GENERATORS, COMPOSITE OF SEVERAL MAKES AND MODELS

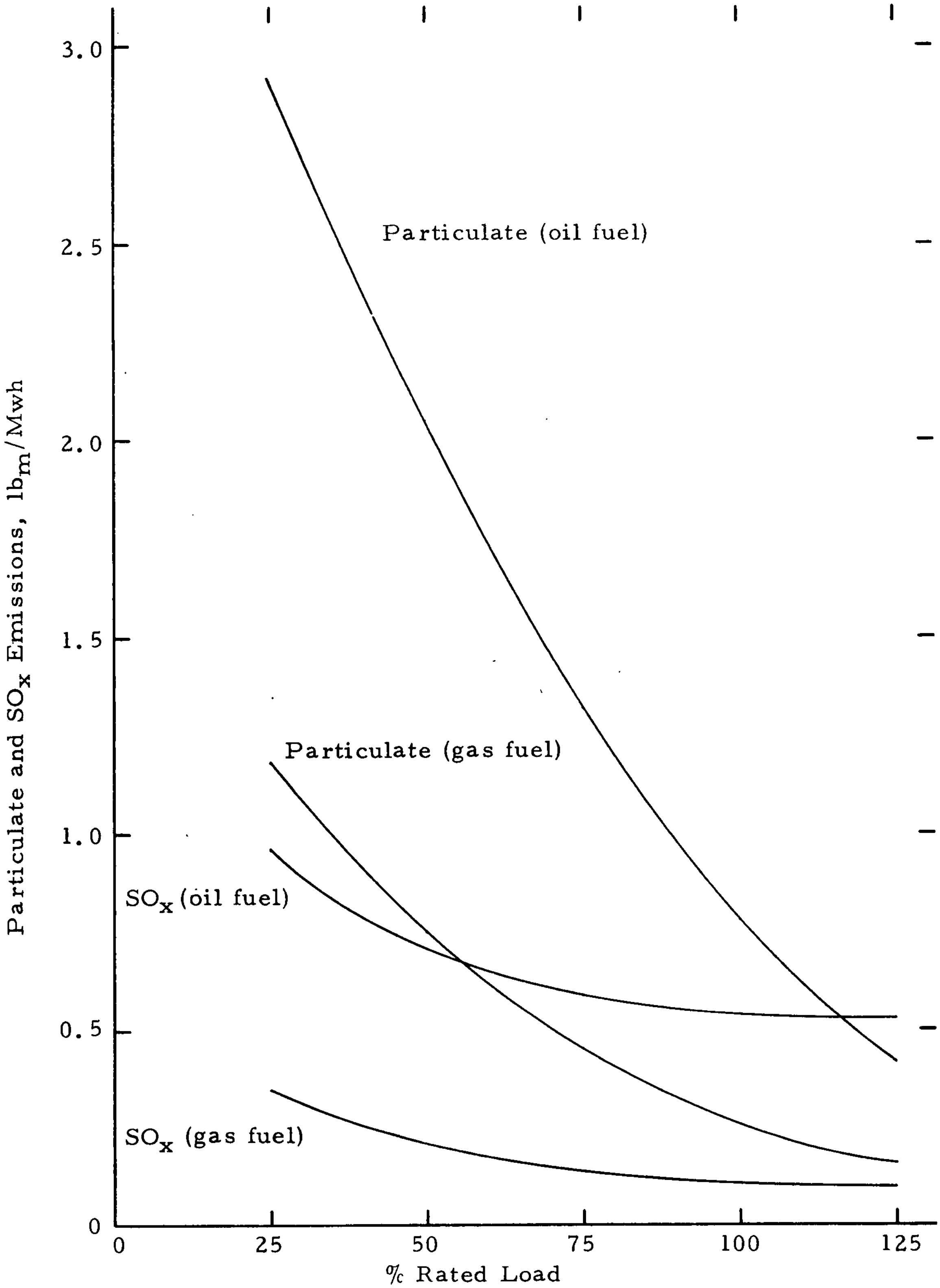

FIGURE 5. SPECIFIC EMISSIONS OF PARTICULATE AND SO_x AS A FUNCTION OF LOAD FOR GAS TURBINE-POWERED GENERATORS, COMPOSITE OF SEVERAL MAKES AND MODELS

lb_m/hr and HC emissions are 53 lb_m/hr. All these data were obtained from various outside sources(1-13), and none were confirmed by tests under the subject contract.

Based on information derived from other references, a cycle of operation will be postualted for electric utility turbines including various part- and full-load conditions. This cycle will be presented later in the report, and it will be used with emissions values and population/usage information to estimate national emission factors and impact.

IV. PRESENTATION OF POPULATION AND USAGE DATA

Data available on the population and usage of gas turbine electric utility powerplants are fairly extensive[14-20], and information from the various sources appears to be in substantial agreement. The best information source at this point is the Federal Power Commission, and data referenced by the Sawyer-Farmer article in Gas Turbine International[14] were obtained on F. P. C. Form No. 1 for 1971. This form must be filled out each year by major utilities and consists of operating and financial data. The statistics developed from the above-mentioned article are not quite all-inclusive, even for 1971, because utility companies having electric revenues of $1,000,000 or less are exempt from filling out the F. P. C. form. Moreover, the article[14] covers only publicly-owned utilities not privately- or investor-owned ones. Despite these small shortcomings, the available statistics appear to include about 87 percent of the gas turbine power used for electric generation in 1971, which is a very good representation.

Some of the data on total power output capability of turbines in electric generation service are summarized in Table 2, indicating generally good agreement. For the purposes of this report, the F. P. C. estimate for 1972 will be assumed as the correct total power capability; and the makeup of the national population on the basis of manufacturer and type will be assumed to be the same as given in the "industry estimate" column of Table 2.

TABLE 2. SUMMARY OF POWER OUTPUT CAPABILITY OF GAS TURBINE ELECTRIC UTILITY POWERPLANTS

Turbine Category	Total Power Output Capability in Megawatts				
	*GTI Article, 1971[14]	FPC Estimates, All Utilities[21]		Industry Est., 1972[14]	Units in Service Plus Orders as of 12/71[14]
		1971	1972		
All	18,977	21,774	27,918	28,326	26,446
G. E.	7,759	------	------	11,600	11,366
TP&M	4,423	------	------	11,523	6,060
Turbodyne	3,502	------	------		4,251
Westinghouse	2,980	------	------	4,846	4,456
Others	313	------	------	357	313

*Includes only those utilities submitting F. P. C. form No. 1 for 1971

Of the 253 generating stations listed in Reference 14, 137 have more than one turbine-generator unit. Consequently, it is not possible to know how many hours each turbine was operated during 1971 for these multiple-turbine plants. The remaining 116 (single-turbine) units, however, were operated an average of 1196 hours during 1971 (or 13.7 percent of the time); and their average load factor (percent of rated load) during operation was 86.8 percent. This information alone is not adequate for determining a representative operating pattern for electric utility turbines, but it should help prevent serious errors.

The desired end product of this report includes emission factors for commonly-used turbines as well as estimates of emissions from electric utility turbines on both a national and a regional basis. Up to this point sufficient information has been developed to achieve the end goals, with the exception of an operating cycle for the engines. The need for a cycle shows up in attempting to determine just where on the specific emission curves (given as Figures 1 through 5) one should choose operating points and how much importance should be given to each point. Assuming that the 86.8 percent load factor applies to all turbines being considered, this factor becomes the primary criterion in the cycle. Other helpful information is that turbines in peaking service normally undergo about 250 starts per year(19), and that each day of operation probably includes one hour or less under no-load conditions(9).

Using 1196 hours' operation per year and 250 starts per year as normal, the resulting average operating day is about 4.8 hours long. One hour no-load time per day would be about 21 percent of operating time, which is considered somewhat excessive. For economy considerations, turbines are not run at off-design conditions any more than necessary, so time spent at intermediate power points is probably minimal. The bulk of turbine operation must be at base or peak load to achieve the high load factor already mentioned.

If it is assumed that time spent at off-design conditions includes 15 percent at zero load and 2 percent each at 25 percent, 50 percent, and 75 percent load, then the percentages of operating time at rated load (100 percent) and peak load (assumed to be 125 percent of rated) can be calculated to produce an 86.8 percent load factor. These percentages turn out to be 19 percent at peak and 60 percent at rated load, and the postulated cycle based on this line of reasoning is summarized in Table 3.

It is obvious that different values for time at base and peak loads could be obtained by changing the total time at lower loads (0 through 75 percent) or by changing the distribution of time spent at lower loads. The cycle given in Table 3 seems reasonable, however, considering the fixed load factor and the economies of turbine operation. Note that the cycle determines only the importance of each load condition in computing composite emission factors for each type of turbine, not overall operating hours.

TABLE 3. POSTULATED OPERATING CYCLE FOR ELECTRIC UTILITY TURBINES

% of Rated Power	% Operating Time Spent at Condition	Time at Condition Based on 4.8 hr Day in Hours	Time at Condition Based on 4.8 hr Day in Minutes	Contribution to Load Factor at Condition
0	15	0.72	43	0.00 x 0.15 = 0.0
25	2	0.10	6	0.25 x 0.02 = 0.005
50	2	0.10	6	0.50 x 0.02 = 0.010
75	2	0.10	6	0.75 x 0.02 = 0.015
100 (base)	60	2.88	173	1.0 x 0.60 = 0.60
125 (peak)	19	0.91	55	1.25 x 0.19 = 0.238
		4.81	289	$\sum$ = Load Factor = 0.868

For the purposes of this report, the operating cycle in Table 3 will be used to compute emission factors, recognizing that it is only an estimate of actual operating patterns.

V. DEVELOPMENT OF EMISSION FACTORS

The factors which are the required end product of this report section should be in such a form as to yield mass emissions in lb_m/hr for specific turbine plants when multiplied by the ratings of those plants in megawatts. In other words, the factors should be composites and expressed in lb_m/megawatt hour. For the purposes of this report, NO_x emission factors will be determined for seven combinations of fuel type, gas generators, and turbines. These combinations follow those described in Figures 1 and 2 except that an average value will be chosen to represent the G.E. model 5000 units, since population statistics do not include the "-LA" and "-N" type designations. The turbine units which do not fall into one of the major classifications shown in Figures 1 and 2 will be grouped with the classifications to which they are most closely related. The emission factors for other pollutants (HC, CO, particulate, and SO_x) will be assumed to be uniform for all the types of turbines, since insufficient information is available on which to base any other conclusion.

Factors for NO_x emissions by operating condition can be found in Table 4, in terms of (lb_m/hr)/rated load for the upper part of the table, and in terms of time-weighted (lb_m/hr)/rated load for the lower part of the table. The summations of weighted mass rates at the bottom of the table are actually composite emission factors, and it should be noted that they bear a strong resemblance to the unweighted factors for 100 percent of rated power in the upper portion of the table, although the composites are all slightly lower.

Factors for emissions of HC, CO, particulate, and SO_x are found in Table 5, and are quite low compared with NO_x factors (Table 4), with the exception of CO. Since the factors in Table 5 are based on relatively few data points, they should be considered somewhat less accurate than the NO_x factors. The SO_x emission factor for oil fuel is based on a fuel sulfur content of approximately 0.05 percent by weight, while that for gas fuel is based on experimental data rather than an assumed sulfur content. The data noted as estimates (with asterisks) were based on extrapolation of concentration data to zero load, not on actual data taken at that condition. Subject to the qualifications and assumptions already expressed, then, the composite emission factors from Table 4 and 5 will be used with population and usage data already discussed to compute national impact estimates. The final reports on other categories of engines have included data on aldehyde and light hydrocarbon concentrations (and mass emissions of aldehydes, in some cases), but no such data could be located for electric utility turbines.

If it is desired to make impact calculations on some basis other than that described above, data presented in Table 6 will be helpful. The top half

TABLE 4. NO_x EMISSION FACTORS FOR ELECTRIC UTILITY TURBINES

% Rated Power	NO_x Emissions in (lb_m/hr)/Rated Load for TP&M GG4-FT4, Gas Fuel	TP&M GG4-FT4, Oil Fuel	Turbodyne GG4-Worth., Gas Fuel	Turbodyne GG4-Worth., Oil Fuel	GE 5000	GE 7000	Westinghouse
0	*1.0	*1.0	*1.0	*1.0	0.69	0.49	2.30
25	1.22	2.62	1.28	3.10	3.45	2.05	4.00
50	2.30	5.15	2.00	4.95	4.70	2.65	5.80
75	3.90	8.25	2.70	6.45	6.45	3.90	8.10
100	6.40	12.2	3.40	7.80	9.80	6.30	11.6
125	9.88	17.4	4.38	9.25	15.0	11.1	16.2

% Rated Power	Time-Based Mode Weight	Weighted NO_x Emissions in (lb_m/hr)/Rated Load for TP&M GG4-FT4, Gas Fuel	TP&M GG4-FT4, Oil Fuel	Turbodyne GG4-Worth., Gas Fuel	Turbodyne GG4-Worth., Oil Fuel	GE 5000	GE 7000	Westinghouse
0	0.15	*0.15	*0.15	*0.15	*0.15	0.10	0.07	0.34
25	0.02	0.02	0.05	0.03	0.06	0.07	0.04	0.08
50	0.02	0.05	0.10	0.04	0.10	0.09	0.05	0.12
75	0.02	0.08	0.16	0.05	0.13	0.13	0.08	0.16
100	0.60	3.84	7.32	2.04	4.68	5.88	3.78	6.96
125	0.19	1.88	3.31	0.83	1.76	2.85	2.11	3.08
$\sum$ =	Composite Emission Factor	= 6.02	11.1	3.14	6.88	9.12	6.13	10.7

* Estimated

TABLE 5. FACTORS FOR EMISSIONS OF HC, CO, PARTICULATE, AND SO_x FROM ELECTRIC UTILITY TURBINES

% Rated Power	Emissions in (lb_m/hr)/Rated Load for					
	HC	CO	*Particulate Gas Fuel	*Particulate Oil Fuel	SO_x Gas Fuel	SO_x Oil Fuel
0	2.7	8.6	**0.2	**0.5	**0.05	0.17
25	1.1	3.2	0.3	0.7	0.088	0.24
50	0.8	0.8	0.4	1.0	0.10	0.34
75	0.6	0.9	0.3	1.0	0.10	0.44
100	0.5	1.0	0.3	0.8	0.10	0.54
125	0.2	1.0	0.2	0.5	0.12	0.66

% Rated Power	Time-Based Mode Weight	Weighted Emissions in (lb_m/hr)/Rated Load for					
		HC	CO	*Particulate Gas Fuel	*Particulate Oil Fuel	SO_x Gas Fuel	SO_x Oil Fuel
0	0.15	0.40	1.29	**0.03	**0.08	**0.008	0.026
25	0.02	0.02	0.06	0.006	0.01	0.002	0.005
50	0.02	0.02	0.02	0.008	0.02	0.002	0.007
75	0.02	0.01	0.02	0.006	0.02	0.002	0.009
100	0.60	0.30	0.60	0.18	0.48	0.060	0.324
125	0.19	0.04	0.19	0.04	0.10	0.024	0.125
$\sum$ = Composite Emission Factor =		0.79	2.18	0.27	0.71	0.098	0.50

* Based on wet collection method such as Los Angeles Air Pollution Control District technique

** Estimated

TABLE 6. COMPOSITE EMISSION FACTORS FOR THE 1971 POPULATION OF ELECTRIC UTILITY TURBINES

Pollutant	Emission Factors, (lb_m/hr) / Rated Load: Entire Population	Gas-Fired Only	Oil-Fired Only
NO_x	8.84	7.81	9.60
HC	0.79	0.79	0.79
CO	2.18	2.18	2.18
Particulate	0.52	0.27	0.71
SO_x	0.33	0.098	0.50

Pollutant	Composite Factors, Fuel Basis: ($lb_m/10^6\ ft^3$ gas) *	($lb_m/10^3$ gal oil) **
NO_x	413.	67.8
HC	42.	5.57
CO	115.	15.4
Particulate	14.	5.0
SO_x	5.2	3.5

* Computed for emissions during gas firing only
**Computed for emissions during oil firing only

of Table 6 gives separate factors for units gas-fired and oil-fired, and the bottom half gives fuel-based factors which could be used to estimate emission rates when overall fuel comsumption data are available. It would also be desirable to have fuel-based emission factors on a mode basis, but fuel consumption data available are not adequate for this purpose.

VI. ESTIMATION OF NATIONAL EMISSIONS IMPACT

Use of the emission factors developed in Section V for the estimation of national impact requires the rated power output of the stations (in megawatts) and the number of hours each turbo-generator unit was used. While the usage figures for single-turbine units in the statistics(14) are explicit, those for multiple-turbine units are not. It appears that the usage figures for multiple-turbine units include all hours during which any of a station's turbines were operating, not just the hours when they were all operating or an average number of hours for each turbine. As mentioned previously, the load factor during operation of single-turbine units averaged 86.8 percent; so it will be assumed that this factor applies to multiple-turbine units also. This assumption indicates that a correction can be made to the usage (in hours) of multiple-turbine units in the form:

$$\text{hours usage at } 86.8\% \text{ load factor} = \frac{\text{calculated load factor}}{86.8\%} \times \text{hours usage given}$$

while still retaining the overall net generation value intact. This correction prevents overstating emissions from stations which ran at least part of the time with one or more turbo-generator units inoperative.

Computation of emissions impact on a national basis is quite straightforward for the available 1971 data, as shown in Table 7. Units listed in the statistics(14) with gas as the primary fuel were assumed to operate on gas 75 percent of the time, and those listed with oil as primary were assumed to operate on oil 75 percent of the time. Updating the results to reflect the assumed 1972 population will be done by simply increasing the contribution of electric utility turbines in proportion to their assumed increase in available power output. The result of this step is shown in Table 8, noting that the brand name and model composition of the 1972 population is very similar to that of the 1971 population. These estimates assume uncontrolled engines even in areas where controls are now in force, but this factor should cause only very small errors. To place these impact estimates in perspective, they are compared with revised 1970 EPA Inventory Data(22) in Table 9. It appears that NO_x and particulate emissions from electric utility turbines are considerably more significant than the other contaminants but are still only around 1 percent of national totals.

No data are presently available on the seasonal aspects of emissions from electric utility turbines, but it would be expected that their usage (and consequently their emissions) would occur primarily in the summer months when overall electric power demand is at its peak. This expectation is based on the idea that gas turbines will be operated only when absolutely necessary, since their specific operating costs are higher than the larger steam plants. Emissions can be broken down

TABLE 7. COMPUTATIONS LEADING TO 1971 NATIONAL IMPACT ESTIMATES FOR ELECTRIC UTILITY GAS TURBINES

Turbine Category	Fuel	Rated Load x Hours, Mwh x 10^{-6}	Tons Emitted During 1971				
			NO_x	HC	CO	*Part.	SO_x
TP&M	gas	1.462	4,400	-----	------	195	70
	oil	4.348	24,200	-----	------	1550	1100
	all	5.810	28,600	2,300	6,350	1740	1170
Turbodyne	gas	1.910	3,000	-----	------	260	95
	oil	1.652	5,700	-----	------	600	415
	all	3.562	8,700	1,400	3,880	860	510
GE 5000	gas	4.162	------	-----	------	550	205
	oil	5.195	------	-----	------	1850	1300
	all	9.357	42,600	3,700	10,200	2400	1500
GE 7000	oil	0.227	695	90	248	80	55
Westing-house	gas	2.095	------	-----	------	285	105
	oil	1.290	------	-----	------	460	325
	all	3.385	18,100	1,350	3,690	745	430
Others	gas	0.022	------	-----	------	3	1
	oil	0.168	------	-----	------	60	42
	all	0.190	845	75	208	63	43

* Wet collection method such as LA APCD technique

TABLE 8. ANNUAL EMISSION RATES FROM ELECTRIC UTILITY TURBINES BASED ON NATIONAL POPULATION AS OF 12/31/72

Emission Rates in tons/year Based on 1972 Population				
NO_x	HC	CO	Particulate	SO_x
146,000	13,100	36,100	8640	5400

TABLE 9. COMPARISON OF ELECTRIC UTILITY TURBINE NATIONAL IMPACT ESTIMATES WITH EPA NATIONWIDE AIR POLLUTANT INVENTORY DATA

Contaminant	1970 EPA Inventory Data, 10^6 tons/year[22] (Revised)		Electric Utility Turbine Estimates as Percent of	
	All Sources	Mobile Sources	All Sources	Mobile Sources
NO_x	22.1	11.0	0.661	1.33
HC	27.3	15.2	0.0480	0.0862
CO	100.7	78.1	0.0358	0.0462
Particulate	25.5	0.9	*0.0339	*0.960
SO_x	33.4	1.0	0.0162	0.545

* Data based on wet collection methods

regionally in almost any way desired, since records are kept on individual units. For the purposes of this report, seven geographic areas will be used to outline the national distribution of emissions from electric utility turbines, as described by Table 10. The emissions released into each of these areas are listed in Table 11, and it can be noted that these emissions tend to occur in areas where urban and suburban populations are substantial rather than in more rural areas.

TABLE 10. DEFINITION OF AREAS USED TO OUTLINE DISTRIBUTION OF EMISSIONS FROM GAS TURBINE ELECTRIC UTILITY POWERPLANTS

States in Area						
1	2	3	4	5	6	7
Maine	Penn.	Ohio	Tenn.	Texas	Calif.	Other States
Vermont	New Jersey	Indiana	North Car.	Louis.		
New Hamp.	Delaware	Illinois	South Car.	Ark.		
Conn.	Dist. of Col.	Ken.	Georgia	Ok.		
Rhode Is.	Maryland	Mich.	Alabama			
Mass.	West Va.	Wis.	Miss.			
New York	Virginia		Fla.			

TABLE 11. BREAKDOWN OF EMISSIONS FROM ELECTRIC UTILITY TURBINES BY GEOGRAPHIC AREA

Contaminant	Emissions by Area in tons/year Based on 1972 Population						
	1	2	3	4	5	6	7
NO_x	39,500	39,000	34,400	18,600	6,610	*3,020	5,170
HC	3,410	3,430	3,140	1,880	518	260	449
CO	9,410	9,470	8,660	5,190	1,430	719	1,240
** Particulate	2,790	2,410	1,890	986	188	140	231
SO_x	1,910	1,560	1,100	547	75	78	127

* Based on uncontrolled engines - value for controlled engines would be somewhat lower(23, 24)

** Wet collection method

VII. SUMMARY

This report is the end product of a study on emissions from gas turbine electric utility engines, and it is Part 6 of a planned seven-part final report on "Exhaust Emissions From Uncontrolled Vehicles and Related Equipment Using Internal Combustion Engines," Contract EHS 70-108. It includes summaries of test data and discussion on emissions from a number of engine types, as well as estimated emission factors and national emissions impact. Unlike the other six reports in the characterization series, this report does not contain any data developed under the subject contract but is rather based on work performed by other agencies and groups. As a part of the final report on the characterization phase of EHS 70-108, this report does not include information on aircraft turbine emissions, outboard motor crankcase drainage, or locomotive emissions control technology. These three latter areas have been or will be reported on separately.

Measurements used in compiling this report were acquired by a variety of techniques and included hydrocarbons, CO, NO_x, and sometimes particulate and/or SO_x. The NO_x data are considered most reliable, and both HC and particulate data are considered least reliable with CO and SO_x reliability somewhere in between.

Expressing emissions from electric utility turbines as percentages of 1970 national totals from all sources, they appear to account for approximately 0.6 percent of NO_x, 0.05 percent of hydrocarbons, 0.04 percent of CO, 0.03 percent of particulate, and 0.02 percent of SO_x. As percentages of 1970 mobile source totals, these turbines are estimated to account for about 1.3 percent of NO_x, 0.09 percent of HC, 0.05 percent of CO, 1.0 percent of particulate, and 0.5 percent of SO_x. This latter comparison has little logical basis, since the engines in question are essentially stationary; but it is drawn to keep continuity in form with the other engine classes investigated under the subject contract.

Although overall emissions from electric utility turbines are not a large percentage of total emissions, it should be noted that they do occur in urban/suburban areas where they have a good potential to affect people. It should also be noted that these emissions probably occur during afternoon pollution peak hours and during summer when other air pollution problems may be severe. The potential growth of turbine usage for power generation is quite substantial, although the Federal Power Commission has estimated that the fraction of total electric power generated by turbines will probably not increase substantially in the near term.

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APPENDIX

EMISSION CONCENTRATION AND RATE DATA

TABLE A-1. CONCENTRATION AND RATE DATA AS OBTAINED FROM REFERENCES

Engine Model	Location	Fuel	% Peak Load	NO_x	HC	CO	Part.	SO_x	Others
GG4A-8	So. Cal. Ed., Huntington Beach	Gas	72	65 ppm	----------	----------	--------	----------	CO_2-1.8, O_2-17.6
		Oil	72	93 ppm	----------	----------	$\frac{0.0071\ gr}{SCF}$	----------	CO_2-2.5, O_2-17.5
GG4A-8	So. Cal. Ed., Etiwanda	Oil(1)	84	73 ppm	0 ppm C_6	0	$\frac{0.015\ gr}{SCF^{(5)}}$	----------	CO_2-1.8, O_2-18.4
		Oil(2)	100	92 ppm	0 ppm C_6	0	$\frac{0.020\ gr}{SCF^{(5)}}$	----------	CO_2-2.0, O_2-18.2
		Oil(2)	100	99 ppm	----------	----------	$\frac{0.016\ gr}{SCF^{(5)}}$	----------	O_2-18.2
		Gas	84	52 ppm	0 ppm C_6	10 $\left(\frac{7.5\ lb_m}{hr}\right)$	$\frac{0.009\ gr}{SCF^{(5)}}$	----------	CO_2-1.2, O_2-18.0
		Oil(3)	100	100 ppm	0 ppm C_6	0	$\frac{0.016\ gr}{SCF^{(5)}}$	----------	CO_2-2.7, O_2-16.8
		Oil	84	73 ppm	7 ppm C_6 (16 lb_m/hr)	0	$\frac{0.022\ gr}{SCF^{(5)}}$	----------	CO_2-2.5, O_2-17.4
TP4-2	Not Given	Oil	100	165 ppm $\left(\frac{0.89\ lb_m}{10^6\ BTU}\right)$	----------	----------	--------	----------	--------------
		Gas	100	115 ppm $\left(\frac{0.62\ lb_m}{10^6\ BTU}\right)$	----------	----------	--------	----------	--------------
		Oil(4)	91	20.8 ppm $\left(\frac{0.112\ lb_m}{10^6\ BTU}\right)$ (53 lb_m/hr)	----------	----------	--------	----------	--------------
P & W, Type N.A.	Not Given	Oil	100	189 ppm $\left(\frac{0.9\ lb_m}{10^6\ BTU}\right)$	----------	----------	--------	----------	--------------
		Gas	100	138 ppm $\left(\frac{0.66\ lb_m}{10^6\ BTU}\right)$	----------	----------	--------	----------	--------------
FT4SC	Not Given	Oil	Low Idle	----------------	$\frac{18.6\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{54.2\ lb_m}{10^3\ lb_m\ fuel}$	--------	----------	--------------
		Oil	Synch. Idle	----------------	$\frac{15.4\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{41.3\ lb_m}{10^3\ lb_m\ fuel}$	--------	----------	--------------
		Oil	80.5	----------------	$\frac{0.8\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{1.1\ lb_m}{10^3\ lb_m\ fuel}$	--------	----------	--------------
		Oil	100	----------------	$\frac{0.05\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{0.75\ lb_m}{10^3\ lb_m\ fuel}$	--------	----------	--------------
TP4-2	Not Given	Oil	80	$\frac{0.84\ lb_m\ NO_x}{10^6\ BTU}$	----------	----------	--------	----------	--------------
		Oil	100	$\frac{0.96\ lb_m\ NO_x}{10^6\ BTU}$	----------	----------	--------	----------	--------------
		Gas	100	$\frac{0.70\ lb_m\ NO_x}{10^6\ BTU}$	----------	----------	--------	----------	--------------
		Gas	36	65 ppm	----------	----------	--------	----------	--------------
FT4A-9DF	Burbank Public Service Co.	Gas	23	21 lb_m NO_2/hr	under 10 ppm C	25 ppm	$\frac{0.0026\ gr}{SCF}$	1.0 ppm SO_2	CO_2-0.6, O_2-20.0
		Gas	55	79 lb_m NO_2/hr	----------	----------	--------	----------	--------------
		Gas	64	84 lb_m NO_2/hr	under 10 ppm C	17 ppm	$\frac{0.0018\ gr}{SCF}$	2.6 ppm SO_2	CO_2-1.9, O_2-17.6
		Gas	73	85 lb_m NO_2/hr	----------	----------	--------	----------	--------------
		Gas	81	89 lb_m NO_2/hr	10 ppm C	25 ppm	$\frac{0.0019\ gr}{SCF}$	3.0 ppm SO_2	CO_2-3.2, O_2-15.4

(1) plus 50 ppm "catalyst"
(2) plus 100 ppm "catalyst"
(3) plus 150 ppm "catalyst"
(4) plus steam
(5) at 12% CO_2

TABLE A-1 (Cont'd). CONCENTRATION AND RATE DATA AS OBTAINED FROM REFERENCES

Engine Model	Location	Fuel	% Peak Load	NO_x	HC	CO	Part.	SO_x	Others
FT4A-9DF	Burbank Public Service Co.	Oil	23	52 lb_m NO_2/hr	under 10 ppm C	23 ppm	$\frac{0.0058\ gr}{SCF}$	1.2 ppm SO_2	CO_2-0.9, O_2-20.0
		Oil	55	152 lb_m NO_2/hr	-----------	-----------	--------	-----------	---------------
		Oil	64	164 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.0043\ gr}{SCF}$	2.0 ppm SO_2	CO_2-2.1, O_2-17.7
		Oil	73	211 lb_m NO_2/hr	-----------	-----------	--------	-----------	---------------
		Oil	81	245 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.0057\ gr}{SCF}$	1.8 ppm SO_2	CO_2-2.5, O_2-17.4
FT4A	Dow Plant, Pittsburg, Cal.	Gas	28	29 lb_m NO_2/hr	none detected	17 ppm	$\frac{0.036\ gr}{SCF^{(5)}}$	0.33 ppm SO_2	CO_2-1.5, O_2-18.0
		Gas	54	60 lb_m NO_2/hr	under 10 ppm C	17 ppm	$\frac{0.029\ gr}{SCF^{(5)}}$	0.62 ppm SO_2	CO_2-2.0, O_2-17.6
		Gas	70	102 lb_m NO_2/hr	under 10 ppm C	25 ppm	$\frac{0.026\ gr}{SCF^{(5)}}$	0.29 ppm SO_2	CO_2-2.2, O_2-17.3
		Gas	88	163 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.015\ gr}{SCF^{(5)}}$	0.72 ppm SO_2	CO_2-2.3, O_2-17.0
		Gas	98	207 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.022\ gr}{SCF^{(5)}}$	1.47 ppm SO_2	CO_2-2.5, O_2-16.5
GG4Ax8	So. Cal. Edison	Oil	100	70 ppm	-----------	under 10 ppm	$\frac{0.007\ gr}{SCF}$	-----------	CO_2-2.6, O_2-17.4
		Gas	100	35 ppm	-----------	-----------	--------	-----------	CO_2-1.9, O_2-17.6
GG4Ax8	So. Cal. Edison	Oil	25	52 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.061\ gr}{SCF^{(5)}}$	3.5 ppm SO_2	CO_2-1.8, O_2-18.1
		Oil	60	93 lb_m NO_2/hr	-----------	-----------	--------	-----------	CO_2-2.5, O_2-17.6
		Oil	74	120 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.075\ gr}{SCF^{(5)}}$	4.2 ppm SO_2	CO_2-2.3, O_2-17.8
		Oil	81	135 lb_m NO_2/hr	-----------	-----------	--------	-----------	CO_2-2.8, O_2-17.2
		Oil	92	154 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.041\ gr}{SCF^{(5)}}$	3.8 ppm SO_2	CO_2-2.7, O_2-17.2
		Gas	28	20 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.02\ gr}{SCF^{(5)}}$	1.5 ppm SO_2	CO_2-1.4, O_2-18.4
		Gas	66	37 lb_m NO_2/hr	-----------	-----------	--------	-----------	CO_2-2.0, O_2-17.7
		Gas	77	44 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.019\ gr}{SCF^{(5)}}$	5.0 ppm SO_2	CO_2-1.9, O_2-17.8
		Gas	88	62 lb_m NO_2/hr	-----------	-----------	--------	-----------	CO_2-2.1, O_2-17.3
		Gas	99	66 lb_m NO_2/hr	under 10 ppm C	under 10 ppm	$\frac{0.011\ gr}{SCF^{(5)}}$	2.2 ppm SO_2	CO_2-2.2, O_2-17.2
MS5001-LA	Not Given	Oil	92	150 ppm (dry)	-----------	0	--------	-----------	O_2-15.5
		Gas	92	85 ppm (dry)	-----------	500 ppm (dry)	--------	-----------	O_2-15.5
		Oil	95	110 ppm (dry)	-----------	under 10 ppm (dry)	--------	-----------	CO_2-3.5, O_2-15.1
		Gas	100	88 ppm (dry)	-----------	under 10 ppm (dry)	--------	-----------	CO_2-2.8, O_2-15.3
MS5001-N	Not Given	N.A.	0	-----------------	$\frac{13\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{50\ lb_m}{10^3\ lb_m\ fuel}$	--------	-----------	---------------
		N.A.	7(Synch. Idle)	-----------------	$\frac{7.0\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{34\ lb_m}{10^3\ lb_m\ fuel}$	--------	-----------	---------------
		N.A.	90	-----------------	$\frac{\angle 0.06\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{1.0\ lb_m}{10^3\ lb_m\ fuel}$	--------	-----------	---------------
		N.A.	100	-----------------	$\frac{\angle 0.06\ lb_m}{10^3\ lb_m\ fuel}$	$\frac{0.7\ lb_m}{10^3\ lb_m\ fuel}$	--------	-----------	---------------

TABLE A-1 (Cont'd). CONCENTRATION AND RATE DATA AS OBTAINED FROM REFERENCES

Engine Model	Location	Fuel	% Peak Load	NO_x	HC	CO	Part.	SO_x	Others
MS5001-SC	Not Given	Oil	86	0.70 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Oil	100	0.78 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Oil(6)	86	0.50 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Oil(6)	100	0.55 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Oil(7)	86	0.30 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Oil(7)	100	0.28 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Gas	86	0.55 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Gas(6)	86	0.35 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
MS7001-SC	Not Given	Oil	91	0.92 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
		Oil	100	1.1 $lb_m/10^6$ BTU	----------	----------	-------	----------	----------
MS5001-LA	Mfr. Data	Oil	5	17 ppm	----------	----------	-------	----------	----------
		Oil	12	34 ppm	----------	----------	-------	----------	----------
		Oil	25	48 ppm	----------	----------	-------	----------	----------
		Oil	50	68 ppm	----------	----------	-------	----------	----------
		Oil	75	108 ppm	----------	----------	-------	----------	----------
		Oil	100	188 ppm	----------	----------	-------	----------	----------
MS5001-N	Mfr. Data	Oil	4	17 ppm	----------	----------	-------	----------	----------
		Oil	10	30 ppm	----------	----------	-------	----------	----------
		Oil	20	40 ppm	----------	----------	-------	----------	----------
		Oil	40	55 ppm	----------	----------	-------	----------	----------
		Oil	60	78 ppm	----------	----------	-------	----------	----------
		Oil	80	120 ppm	----------	----------	-------	----------	----------
		Oil	100	180 ppm	----------	----------	-------	----------	----------
MS7001-A	Mfr. Data	Oil	8	28 ppm	----------	----------	-------	----------	----------
		Oil	17	32 ppm	----------	----------	-------	----------	----------
		Oil	25	38 ppm	----------	----------	-------	----------	----------
		Oil	33	40 ppm	----------	----------	-------	----------	----------
		Oil	42	45 ppm	----------	----------	-------	----------	----------
		Oil	58	63 ppm	----------	----------	-------	----------	----------
		Oil	75	90 ppm	----------	----------	-------	----------	----------
		Oil	92	143 ppm	----------	----------	-------	----------	----------
W251-SC	Not Given	Oil	100	220 ppm	----------	----------	-------	----------	----------
		Oil(8)	100	57 ppm	----------	----------	-------	----------	----------
W501-SC	Not Given	Oil	100	220 ppm	----------	----------	-------	----------	----------
W251-AA	Not Given	Oil	99	202 ppm (dry)	----------	40 ppm (dry)	-------	----------	O_2-14.0 (dry)
		Oil(9)	100	60 ppm (dry)	----------	10 ppm (dry)	-------	----------	CO_2-3.0 (dry) O_2-13.8 (dry)
W251	Mfr. Data	Oil	0	40 ppm	----------	----------	-------	----------	----------
		Oil	20	52 ppm	----------	----------	-------	----------	----------
		Oil	23	----------	----------	30 ppm	-------	----------	----------
		Oil	28	60 ppm	----------	----------	-------	----------	----------
		Oil	32	----------	----------	23 ppm	-------	----------	----------
		Oil	44	80 ppm	----------	----------	-------	----------	----------
		Oil	48	----------	----------	16 ppm	-------	----------	----------
		Oil	57	100 ppm	----------	----------	-------	----------	----------
		Oil	65	----------	----------	15 ppm	-------	----------	----------
		Oil	68	120 ppm	----------	----------	-------	----------	----------
		Oil	75	140 ppm	----------	----------	-------	----------	----------
		Oil	81	----------	----------	18 ppm	-------	----------	----------
		Oil	84	160 ppm	----------	----------	-------	----------	----------
		Oil	90	180 ppm	----------	----------	-------	----------	----------
		Oil	97	----------	----------	29 ppm	-------	----------	----------
		Oil	100	212 ppm	----------	----------	-------	----------	----------

(6) modified combustor
(7) plus water injection at 1.3% of air rate
(8) plus water injection
(9) plus water injection at 65% of [illegible] rate

TABLE A-1 (Cont'd). CONCENTRATION AND RATE DATA AS OBTAINED FROM REFERENCES

Engine Model	Location	Fuel	% Peak Load	NO_x	HC	CO	Part.	SO_x	Others
W501	Mfr. Data	Oil	0	40 ppm	-----------	-----------	--------	------------	----------------
		Oil	20	52 ppm	-----------	-----------	--------	------------	----------------
		Oil	28	60 ppm	-----------	-----------	--------	------------	----------------
		Oil	44	80 ppm	-----------	-----------	--------	------------	----------------
		Oil	57	100 ppm	-----------	-----------	--------	------------	----------------
		Oil	68	120 ppm	-----------	-----------	--------	------------	----------------
		Oil	75	140 ppm	-----------	-----------	--------	------------	----------------
		Oil	84	160 ppm	-----------	-----------	--------	------------	----------------
		Oil	90	180 ppm	-----------	-----------	--------	------------	----------------
		Oil	100	212 ppm	-----------	-----------	--------	------------	----------------

TABLE A-2. RATE DATA USED TO PLOT FIGURES 1-5
(RESTATEMENT OF TABLE A-1 DATA AFTER PROCESSING)

Engine Model	Fuel	% Peak Load	Emission Rate in lbm/Megawatt hour NOx	HC	CO	Particulate	SOx
GG4A	Gas	72	6.16	----	----	----	----
	Oil(1)	72	8.80	----	----	0.85	----
	Oil(2)	84	5.94	----	----	0.22	----
	Oil(3)	100	6.28	----	----	0.28	----
	Gas	100	6.72	----	----	0.22	----
	Oil(3)	84	4.21	----	0.50	0.089	----
	Oil	100	6.83	----	----	0.30	----
	Oil	84	5.94	1.1	----	0.45	----
FT4	Oil	100	8.4	----	----	----	----
	Gas	100	5.8	----	----	----	----
	Oil(4)	91	1.1	----	----	----	----
FT4-SC	Oil	80	----	0.52	0.73	----	----
	Oil	100	----	0.029	0.45	----	----
FT4-SC	Oil	80	10.8	----	----	----	----
	Oil	100	11.4	----	----	----	----
	Gas	100	6.64	----	----	----	----
	Gas	36	9.1	----	----	----	----
FT4A-9DF	Gas	23	4.2	3.8	6.6	1.3	0.60
	Gas	55	5.7	----	----	----	----
	Gas	64	6.0	0.49	0.81	0.17	0.29
	Gas	73	5.3	----	----	----	----
	Gas	81	5.0	0.62	0.79	0.11	0.21
	Oil	23	10.4	----	8.0	2.8	0.66
	Oil	55	12.7	----	----	----	----
	Oil	64	11.7	----	----	0.57	0.31
	Oil	73	13.2	----	----	----	----
	Oil	81	13.8	----	----	0.62	0.23
FT4A	Gas	28	4.5	----	1.9	0.98	0.085
	Gas	54	4.9	----	1.1	0.59	0.090
	Gas	70	6.3	----	1.4	0.50	0.048
	Gas	88	8.1	----	----	0.28	0.080
	Gas	98	9.2	----	----	0.40	0.15
GG4A	Oil	100	4.9	----	----	0.56	----
	Gas	100	2.4	----	----	----	----

(1) plus 50 ppm catalyst
(2) plus 100 ppm catalyst
(3) plus 150 ppm catalyst
(4) plus steam

TABLE A-2. (Cont'd.) RATE DATA USED TO PLOT FIGURES 1-5 (RESTATEMENT OF TABLE A-1 DATA AFTER PROCESSING)

Engine Model	Fuel	% Peak Load	Emission Rate in lbm/Megawatt hour				
			NO_x	HC	CO	Particulate	SO_x
GG4A	Oil	25	11.6	----	----	2.7	1.2
	Oil	60	8.6	----	----	----	----
	Oil	74	9.1	----	----	1.8	0.63
	Oil	81	9.2	----	----	----	----
	Oil	92	9.3	----	----	0.96	0.46
	Gas	28	4.0	----	----	0.46	0.36
	Gas	66	3.1	----	----	----	----
	Gas	77	3.2	----	----	0.27	0.52
	Gas	88	3.9	----	----	----	----
	Gas	99	3.7	----	----	0.15	0.18
MS5001-LA	Oil	92	7.9	----	----	----	----
	Gas	92	4.5	----	16.	----	----
	Oil	95	6.3	----	----	----	----
	Gas	100	3.8	----	----	----	----
MS5001-N	Oil	7	----	18.	86.	----	----
	Oil	90	----	----	0.67	----	----
	Oil	100	----	----	0.46	----	----
MS5001-SC	Oil	86	13.3	----	----	----	----
	Oil	100	14.0	----	----	----	----
	Oil[5]	86	9.50	----	----	----	----
	Oil[5]	100	9.86	----	----	----	----
	Oil[6]	86	5.71	----	----	----	----
	Oil[6]	100	5.04	----	----	----	----
	Gas	75	7.76	----	----	----	----
	Gas[5]	75	4.95	----	----	----	----
MS7001-SC	Oil	91	15.3	----	----	----	----
	Oil	100	17.4	----	----	----	----
MS5001-LA	Oil	5	25.0	----	----	----	----
	Oil	12	19.6	----	----	----	----
	Oil	25	14.0	----	----	----	----
	Oil	50	9.80	----	----	----	----
	Oil	75	10.4	----	----	----	----
	Oil	100	13.6	----	----	----	----
MS5001-N	Oil	4	25.0	----	----	----	----
	Oil	10	17.2	-----	----	----	----
	Oil	20	11.8	----	----	----	----

[5] modified combustor
[6] plus water injection at 1.3% of air rate

TABLE A-2. (Cont'd.) RATE DATA USED TO PLOT FIGURES 1-5
(RESTATEMENT OF TABLE A-1 DATA AFTER PROCESSING)

Engine Model	Fuel	% Peak Load	Emission Rate in lbm/Megawatt hour				
			NOx	HC	CO	Particulate	SOx
	Oil	40	8.00	----	----	----	----
	Oil	60	7.53	----	----	----	----
	Oil	80	8.70	----	----	----	----
	Oil	100	10.4	----	----	----	----
MS7001-A	Oil	8	16.3	----	----	----	----
	Oil	17	9.34	----	----	----	----
	Oil	25	7.40	----	----	----	----
	Oil	33	5.84	----	----	----	----
	Oil	42	5.25	----	----	----	----
	Oil	58	5.25	----	----	----	----
	Oil	75	5.84	----	----	----	----
	Oil	92	7.59	----	----	----	----
W251-SC	Oil	100	13.8	----	----	----	----
	Oil(7)	100	3.61	----	----	----	----
W501-SC	Oil	100	12.3	----	----	----	----
W251-AA	Oil	99	9.47	----	----	----	----
	Oil(8)	100	2.77	----	----	----	----
W251	Oil	20	16.0	----	----	----	----
	Oil	23	----	----	4.91	----	----
	Oil	28	13.1	----	----	----	----
	Oil	32	----	----	2.72	----	----
	Oil	44	11.2	----	----	----	----
	Oil	48	----	----	1.28	----	----
	Oil	57	10.8	----	----	----	----
	Oil	65	----	----	0.84	----	----
	Oil	68	10.9	----	----	----	----
	Oil	75	11.5	----	----	----	----
	Oil	81	----	----	0.84	----	----
	Oil	84	11.7	----	----	----	----
	Oil	90	12.3	----	----	----	----
	Oil	97	----	----	1.13	----	----
	Oil	100	13.0	----	----	----	----
W501	Oil	20	15.8	----	----	----	----
	Oil	28	13.0	----	----	----	----
	Oil	44	11.1	----	----	----	----
	Oil	57	10.7	----	----	----	----
	Oil	68	10.8	----	----	----	----
	Oil	75	11.4	----	----	----	----
	Oil	84	11.6	----	----	----	----
	Oil	90	12.2	----	----	----	----
	Oil	100	12.9	----	----	----	----

(7) plus water injection
(8) plus water injection at 65% of fuel rate

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

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16. ABSTRACT

This report includes summaries of test data and discussion on emissions from a number of gas turbine electric utility engines. It also covers the estimation of emission factors and national air quality impact of these engines. A regional estimate of the distribution of these emissions is also made.

The data are based on work performed by other agencies and groups. The measurements were made by a variety of techniques and included HC, CO, NO_x, and sometimes particulate and SO_x.

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