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EMISSION CHARACTERISTICS OF CRUDE OIL PRODUCTION OPERATIONS IN CALIFORNIA

FINAL REPORT

PREPARED FOR:

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ABSTRACT

An inventory was conducted of the average annual emissions of air pollutants; NO_x, SO_x, CO, particulate matter and hydrocarbons; from oil production operations in the state of California. The emissions were generated on a lease-by-lease basis and aggregated and reported by (1) oil field (with associated geographical location), (2) County, and (3) Air Basin. Preparation of this emission inventory involved field surveys of representative production sites for equipment inventorying; field tests of oil field IC engines and heaters for emission factor development; and processing of extensive data from the California Division of Oil and Gas, the American Petroleum Institute, and other sources for emissions calculation.

On the basis of this program it was concluded that the emissions from oil production in California are a significant portion of the total emissions from stationary sources. In the South Coast Air Basin alone, oil production accounted for 18 percent of the CO, over 3 percent of the NO_x, 2 percent of the SO_x, over 3 percent of the hydrocarbons and less than 1 percent of the particulate stationary sources emissions during the 1979 study year.

CONTENTS

CONTENTS (continued)

FIGURES

TABLES

TABLES (continued)

TABLES (continued)

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SECTION 1.0

INTRODUCTION

1.1 BACKGROUND

The emission of air pollutants from crude oil production in California is significant. A 1976 inventory conducted by KVB showed 5 percent of the total hydrocarbon emissions in the South Coast Air Basin resulted from crude oil production. In addition to these fugitive hydrocarbons, the engines, heaters, steamers and fireflooding operations in the oil fields produce considerable quantities of nitrogen oxides, sulfur oxides and fine particulate matter.

There were approximately 230 active oil fields and over 43,000 oil wells in California when this program began in 1979, some located in very remote locations. While the California Division of Oil and Gas (DOG) regulates the various oil production operations and maintains location and production data for each well, there was very little information available concerning the type or quantity of equipment located at each site. There are many oil production companies ranging in size from the "major" oil companies to small independent producers who may own only one oil well. In addition, there are many small independent companies who specialize in well drilling, remedial work and welding services as subcontractors to these oil production companies.

The ARB in their continuing effort to upgrade the statewide emissions inventory and provide assistance to the local air pollution control agencies engaged KVB in 1979 to inventory the emissions from primary and secondary oil production. In 1981 the program was expanded to include tertiary or thermally enhanced production. There was a program hold of approximately one year while funding for the latter segment was obtained. This report represents the results of the entire program.

California is the fourth largest producer of crude oil in the United States. As such, the petroleum industry is an important contributor to the state's economy. The industry can be expected to grow in California as production of the vast heavy oil reserves is increased due to the development of improved recovery techniques and economic incentives.

1.2 OBJECTIVES

The primary objective of this program has been to quantify the average annual hydrocarbon, NO_x, SO_x, CO and particulate emissions associated with oil recovery and gas processing for the State of California on an oil field or gas plant, county, air basin and statewide basis. California's oil producing activities are concentrated in the counties of Orange, Los Angeles, Monterey, San Luis Obispo, Santa Barbara, Venture, Kern and Fresno as well as offshore production locations in state and federal waters.

Two secondary objectives were included in the program. The first was to derive valid emission factors for the many small heater treaters and IC engines which are found in many California oil fields. The second was to quantify the annual emissions associated with oil well drilling operations.

1.3 PROGRAM APPROACH

As in any inventory program the basic approach is to locate and identify emission sources and apply suitable emission factors to compute and then categorize the emissions. Because there are so many individual sources of oil production emissions (43,000 oil wells in approximately 230 fields), it was necessary to use sampling procedures in order to develop both the number of sources and emission factors. Realize that in California there are over 1.5 million oil field valves and three million oil field fittings. This report documents the methods used in compiling the emissions data. Various techniques were used to take advantage of existing information. Because so many different techniques were used, the reader may have a difficult time in interrelating the various program facets. This section presents a description of the general approach taken by KVB with the objective of providing the reader a mental framework on which to hang the detailed data which is presented in the following sections. The reader should be aware that this is a generalized description and details or exceptions are not covered. Discussion of those exceptions can be found in the body of the report.

As stated above, the primary objective of the inventory was to compile emissions of the five criteria pollutants, NO_x, SO_x, particulates, THC, and CO by oil field or gas plant, county air basin, and state. To ensure that a proper representation of oil field characteristics and operations were incorporated in the sampling process, oil fields were grouped according to specific parameters. Representative fields from each group were then selected for inventory. The inventory procedures were further refined by inventorying specific leases at each field. The lease was the lowest level on which data were compiled.

KVB crews visited over 30 selected oil production sites including offshore platforms, production islands and gas plants. Detailed counts were made of valves, fittings, and surface equipment associated with petroleum production or gas processing. The estimated 2,500 leases in the state were segregated into 10 categories. Fugitive hydrocarbon emissions models or algorithms were prepared for each of the 10 categories. Two other category models were developed which covered the special cases of (1) gas plants, and (2) onshore treatment facilities which receive crude and gas produced by the offshore platforms.

Fugitive hydrocarbon emissions from sources including valves, fittings, sumps, pits, mechanical oil/water separators, compressors, etc. were quantified on a lease-by-lease basis using the appropriate lease algorithm along with the number of wells on that lease. These fugitive-hydrocarbon sources were inventoried at each production survey site by type (i.e., globe valve, threaded fitting, rotary seal...etc.). Using the hydrocarbon leakage rate data published by the American Petroleum Institute (API) (Ref. 1) the total emissions per hardware item category (i.e. valve, fitting sumps, etc.) was obtained. Summing the emissions from all sources in a particular hardware item category for the production sites surveyed within a lease model group and dividing by the total number of wells surveyed in that group produced an emission algorithm for each hardware-item category in units of lb/day emissions per well. These hardware-item algorithms were then summed to obtain a unique model for that lease which included emissions from valves, fittings, pump, compressor, etc. Then, to estimate the fugitive hydrocarbon emissions from a given lease, the number of wells for that lease were multiplied by that unique lease model.

Tank breathing loss and working loss emissions were calculated as a function of production rate or annual throughput. Based on a model developed from a statistical sampling of lease tank capacities versus annual production rate, the tank capacity for each lease was determined. The lease tankage, in a given field was summed to find total tankage which was used to determine annual breathing loss emissions. The total field production rate was used to determine working loss emissions. These emissions were calculated from algorithms developed from the AP-42 fixed-roof tank emission equations and tankage characteristics specific to the oil fields. Separate algorithms were used for tankage with and without vapor control.

Steam generators, heater treaters, boilers, fire floods and IC engines were inventoried on a field rather than lease basis. The statistical basis for these were IC engine population, heater treater, steam generator and boiler capacity or rated heat input rate, plus incremental oil production rate resulting from fireflooding operations. Emission factors for the various emission sources were developed from KVB's field testing program (conducted under this contract) AP-42 and KVB's tertiary oil recovery report (Ref. 2), previously prepared for ARB.

A computer program, written for this project, aggregated the emissions from each of those sources by field, county...etc. Emissions calculated by the program were expressed as metric tons/year. Each field was located by up to six Universal Transverse Mercator (UTM) coordinates.

Emissions resulting from drilling activities were calculated on a regional basis and reported separately from the program. Additionally, survey and emissions data for steam flood and cyclic steam well vents have been included in the report, but were not incorporated into the computer program.

1.4 SUMMARY OF RESULTS

The primary results obtained in this program were a quantification of NO_x, SO_x, THC, particulates and CO emissions associated with oil production and gas processing on a field or gas plant, county, air basin and statewide basis. These results were limited to Fresno, Kern, Orange, Los Angeles, San Luis Obispo, Monterey, Santa Barbara, and Ventura Counties and the offshore producing locations in state and federal waters. These areas include nearly all the major oil fields in the state. The total annual emissions in metric tons for each facility by county are presented in Table 1.4-1.

Aggregated in this table are emissions associated with tanks, well cellars, sumps and pits, valves, fittings, well heads, pumps, compressors, I.C. engines, heater treaters, steamers and boilers, mechanical oil/water separators, fireflooding, and flares. Not included, as explained below, are emissions associated with oil well drilling and steam enhanced oil recovery well vent emissions.

On the basis of these results, it can be seen that emissions from oil production are a significant portion of the total emissions from stationary sources in California. Table 1.4-2 compares the South Coast Air Basin emissions for petroleum production as estimated by this program to the Draft 1979 Stationary Source Emissions Inventory prepared by the South Coast Air Quality Management District.

Drilling rig emissions were calculated on a regional basis rather than a field-by-field basis. This approach more accurately estimates the total annual emissions and eliminates wide fluctuations which might occur in a given field from year to year due to increases or decreases in drilling activity. Further, the regional approach also accounts for "wildcatting" and other drilling which occur outside specific oil field boundaries.

The results of the analysis for the year 1979 are presented in Table 1.4-3.

Drilling in California is done by electric, gas and diesel powered rigs. In the course of drilling an oil well, a rig's power plant will vary between idle and full load depending upon depth, hardness of formation and

TABLE 1.4-1. SUMMARY OF EMISSIONS FROM PETROLEUM PRODUCTION BY COUNTY AND FIELD IN CALIFORNIA, 1979

County	Field	Pollutant Emissions Metric Tons/Year				
		THC	NOx	CO	Part.	SOx
FRESNO	Burrel	12	--	--	--	--
	Burrel, Southeast	20	--	--	--	--
	Camden	3	--	--	--	--
	Cheney Ranch Gas	13	--	--	--	--
	Coalinga	3,343	1,043	3,266	426	2,887
	Coalinga, Extension	458	33	735	--	--
	Five Points	3	--	--	--	--
	Guijarral Hills	83	6	147	--	--
	Helm	238	34	765	--	--
	Jacalitos	180	33	735	--	--
	Kettleman, North Dome	239	--	--	--	--
	Kreyenhagen	20	--	--	--	--
	Pleasant Valley	10	--	--	--	--
	Raisin City	372	65	1,470	--	--
	Riverdale	218	26	588	--	--
	San Joaquin	17	--	--	--	--
	Turk Anticline	6	--	--	--	--
	Westhaven	8	--	--	--	--
	Subtotal	5,243	1,240	7,706	426	2,887
	(Gas Plant)					
	Coalinga Nose	2,464	2,646	829	2	832
	COUNTY TOTAL	7,707	3,886	8,535	428	3,719
KERN	Ant Hill	82	--	--	--	--
	Antelope Hills	173	--	--	--	--
	Antelope Hills, North	24	--	--	--	--
	Asphalto	353	26	588	--	--
	Beer Nose	13	--	--	--	--
	Belgian Anticline	485	13	2	6	41
	Bellevue	70	6	147	--	--
	Bellevue, West	14	--	--	--	--
	Belridge, North	689	125	16	57	385
	Belridge, South	5,252	1,896	4,319	932	5,642
	Blackwell Corner	40	--	--	--	--
	Buena Vista	2,665	138	2,211	18	124
	Cal Canal	35	--	--	--	--
	Calders Corner	3	--	--	--	--
	Canal	63	9	206	--	--
	Canfield Ranch	386	39	883	--	--
	Carneros Creek	12	--	--	--	--
	Chico-Martinez	26	--	--	--	--
	Cienaga Canyon	5	--	--	--	--
	Coles Levee, North	637	105	2,353	--	--
	Coles Levee, South	46	--	--	--	--
	Commanche Point	66	--	--	--	--
	Cymric	2,944	342	3,730	87	592
	Devils Den	225	--	--	--	--
	Edison	2,570	269	4,421	33	223
	Edison, Northeast	44	37	5	17	115
	Elk Hills	2,446	1,049	23,528	--	1
	English Colony	10	--	--	--	--
KERN (Cont)	Fruitvale	1,324	148	2,066	26	174
	Goosloo	30	--	--	--	--
	Greeley	179	13	295	--	--
	Jasmin	156	--	--	--	--
	Jasmin, West	9	--	--	--	--
	Jerry Slough	3	--	--	--	--
	Kern Bluff	303	97	13	44	298
	Kern Front	2,244	854	1,458	383	2,594
	Kern River	4,409	13,594	3,549	6,189	41,925
	Lakeside	3	--	--	--	--
	Los Lobos	5	--	--	--	--
	Lost Hills	3,667	469	178	225	1,435
	Lost Hills, Northwest	5	--	--	--	--
	McDonald Anticline	308	--	--	--	--
	McKittrick	1,670	733	95	334	2,265
	Midway-Sunset*	16,063	4,745	17,891	2,062	13,856
	Mount Poso	1,360	304	420	137	927
	Mountain View	1,013	131	2,941	--	--
	Paloma	179	--	--	--	--
	Pioneer	10	--	--	--	--
	Pleito	81	--	--	--	--
	Poso Creek	1,272	230	410	103	698
	Railway Gap	96	88	11	40	271
	Rio Bravo	145	1	58	--	--
	Rio Viejo	36	--	--	--	--
	Rosedale	47	--	--	--	--
	Rosedale Ranch	210	33	735	--	--
	Round Mountain	795	--	--	--	--
	San Emidio Nose	40	--	--	--	--
	Semitropic	114	--	--	--	--
	Seventh Standard	9	--	--	--	--
	Strand	199	41	911	--	--
	Tejon	454	79	1,472	6	41
	Tejon Hills	310	--	--	--	--
	Tejon North	355	33	735	--	--
	Temblor Hills	3	--	--	--	--
	Temblor Ranch	10	--	--	--	--
	Ten Section	620	11	1,027	--	--
	Tule Elk	8	--	--	--	--
	Union Avenue	16	3	59	--	--
	Valpredo	3	--	--	--	--
	Welcome Valley	6	--	--	--	--
	Wheeler Ridge	449	83	1,473	8	57
	White Wolf	43	1	58	--	--
	Yowlumne	297	12	265	--	--
	Subtotal	57,936	25,757	78,529	10,707	71,665
	(Gas Plants)					
	Belridge	1,889	2,028	635	1	638
	Buena Vista	369	397	124	--	125
	Cajon	205	221	69	--	69
	Cymric	205	221	69	--	69
	Lost Hills	205	221	69	--	69
	McKittrick	738	793	248	--	250
	Midway-Sunset	1,395	1,498	469	1	471

*Fields in more than one county.

NOTE: Dash represents no emissions or less than one metric ton/year.

TABLE 1.4-1. (CONTINUED)

County	Field	THC	NOx	CO	Part.	SOx
		Pollutant Emissions Metric Tons/Year				
KERN (Cont)	(Gas Plants, cont)	--	--	--	--	--
	North Coles Levee	1,190	1,277	400	1	402
	Rio Bravo	533	572	179	--	180
	South Coles Levee	3,203	3,439	1,077	2	1,082
	Subtotal	9,932	10,667	3,339	5	3,355
	COUNTY TOTAL	67,868	36,424	81,868	10,712	75,020
LOS ANGELES	Aliso Canyon	271	13	295	--	--
	Alondra	7	--	--	--	--
	Bandini	127	26	588	--	--
	Beverly Hills	497	2	234	--	--
	Brea-Olinda*	238	1	--	3	1
	Canton Creek	5	--	--	--	--
	Cascade	47	--	--	--	--
	Castaic Hills	129	26	588	--	--
	Castaic Junction	78	--	--	--	--
	Cheviot Hills	97	--	--	--	--
	Coyote, West*	24	--	--	--	--
	Del Valle	284	12	500	--	--
	Dominguez	514	144	3,236	--	--
	El Segundo	60	1	89	--	--
	Hasley Canyon	32	--	--	--	--
	Honor Rancho	69	5	117	--	--
	Howard Townsite	128	22	501	--	--
	Hyperion	4	--	--	--	--
	Inglewood	1,219	--	--	--	--
	Las Cienegas	51	--	--	--	--
	Las Llajas	13	3	59	--	--
	Lawndale	8	--	--	--	--
	Long Beach	1,511	130	2,941	--	--
	Long Beach Airport	76	4	89	--	--
	Los Angeles, Downtown	16	--	--	--	--
	Los Angeles, East	63	18	412	--	--
	Lyon Canyon	15	--	--	--	--
	Montebello	444	--	--	--	--
	Newgate	5	--	--	--	--
	Newhall	245	--	--	--	--
	Newhall-Potrero	393	33	735	--	--
	Oak Canyon	108	10	234	--	--
	Placerita	533	16	1	1	--
	Playa del Rey	39	--	--	--	--
	Potrero	84	--	--	--	--
	Ramona*	226	26	588	--	--
	Rosecrans	400	46	1,030	--	--
	Rosecrans, East	13	3	59	--	--
	Rosecrans, South	108	20	471	--	--
	Salt Lake	169	--	--	--	--
	Salt Lake, South	51	--	--	--	--
	San Vicente	17	--	--	--	--
	Sansinena	476	--	--	--	--
	Santa Fe Springs	695	92	2,058	--	--
	Saugus	8	--	--	--	--
	Sawtelle	74	1	115	--	--
	Seal Beach*	374	42	941	--	--

County	Field	THC	NOx	CO	Part.	SOx
		Pollutant Emissions Metric Tons/Year				
LOS ANGELES (Cont)	Tapia	63	--	--	--	--
	Torrance	1,285	30	940	--	--
	Union Station	36	--	--	--	--
	Venice Beach	16	--	--	--	--
	Wayside Canyon	14	--	--	--	--
	Whittier	616	--	--	--	--
	Wilmington	3,183	168	4,409	1	--
	Subtotal	15,258	894	21,230	5	1
	(Gas Plants)					
	Dominguez	163	176	55	--	55
	Inglewood	163	176	55	--	55
	Lomita	287	309	97	--	97
	Newhall	1,520	1,632	511	1	513
	Santa Fe Springs	82	88	27	--	28
	Torrance	42	45	14	--	14
	Subtotal	2,257	2,426	759	1	762
	COUNTY TOTAL	17,515	3,320	21,989	6	763
MONTEREY	King City	102	--	--	--	--
	Lynch Canyon	5	--	--	--	--
	McCool Ranch	5	--	--	--	--
	Monroe Swell	15	--	--	--	--
	Paris Valley	10	--	--	--	--
	Quinado Canyon	5	--	--	--	--
	San Ardo	1,534	1,835	239	874	5,632
	COUNTY TOTAL	1,676	1,835	239	874	5,632
ORANGE	Brea-Olinda*	1,786	55	65	27	166
	Coyote, East	496	4	352	--	--
	Coyote, West*	867	20	1,905	--	--
	Esperanza	56	--	--	--	--
	Huntington Beach	4,059	474	10,500	6	42
	Kraemer	19	--	--	--	--
	Newport, West	451	23	3	35	47
	Olive	32	--	--	--	--
	Richfield	677	--	--	--	--
	Seal Beach*	253	43	970	--	--
	Sunset Beach	20	--	--	--	--
	Yorba Linda	707	26	3	12	83
	Subtotal	9,423	645	13,798	80	338
	(Gas Plants)					
	Coyote, East	369	396	125	--	123
	Coyote, West	81	88	27	--	28
	Huntington Beach	411	442	140	--	139
	Subtotal	861	926	292	0	290
	(Offshore Facility)					
	Belmont	92	--	--	--	--
	COUNTY TOTAL	10,376	1,571	14,090	80	628

*Fields in more than one county.

NOTE: Dash represents no emissions or less than one metric ton/year.

TABLE 1.4-1. (CONTINUED)

County	Field	Pollutant Emissions Metric Tons/Year THC	NOx	CO	Part.	SOx
SAN LUIS OBISPO	Arroyo Grande	262	223	29	102	688
	Guadalupe*	651	537	3,755	169	1,148
	Midway-Sunset*	146	19	296	17	3
	Morales Canyon	5	--	--	--	--
	Russell Ranch*	176	35	793	--	--
	Taylor Canyon	8	--	--	--	--
	COUNTY TOTAL	1,248	814	4,873	288	1,839
SANTA BARBARA	Barham Ranch	36	7	147	--	--
	Capitan	59	--	--	--	--
	Careaga Canyon	5	--	--	--	--
	Casmalia	617	106	1,476	18	124
	Cat Canyon	3,132	272	4,538	34	230
	Cuyama, South	318	131	2,941	--	--
	Elwood	45	--	--	--	--
	Four Deer Field	39	--	--	--	--
	Guadalupe*	14	3	59	--	--
	Lompoc	396	--	--	--	--
	Orcutt	936	177	3,971	--	--
	Point Conception	25	--	--	--	--
	Russell Ranch*	103	44	1,000	--	--
	Santa Maria Valley	1,305	191	4,117	--	--
	Zaca	133	--	--	--	--
	Subtotal	7,163	931	18,249	52	354
	(Gas Plants)					
	Gaviota	245	263	82	--	83
	Santa Maria	575	617	193	--	194
	Subtotal	820	880	275		277
	(Offshore Facilities)					
	Alegria	10	--	--	--	--
	Carpenteria	176	--	--	--	--
	Dos Cuadras	50	--	--	--	--
	Elwood, South	12	--	--	--	--
	Summerland	28	--	--	--	--
	Subtotal	276				
	Carpenteria Onshore Facility	1,117	542	1,398		166
	COUNTY TOTAL	9,376	2,353	19,922	52	797
VENTURA	Bardsdale	469	--	--	--	--
	Big Mountain	23	6	117	--	--
	Canada Larga	16	--	--	--	--
	El Rio	5	--	--	--	--
	Eureka Canyon	76	--	--	--	--
	Holser	57	--	--	--	--
	Hopper Canyon	59	10	234	--	--
	Los Posas	5	--	--	--	--
	Montalvo, West	128	--	--	--	--
	Moorpark, West	11	--	--	--	--
	Oak Park	30	--	30	--	--
VENTURA (Cont)	Oakridge	16	--	--	--	--
	Ojai	638	67	1,617	--	--
	Oxnard	417	7	1	--	--
	Piru	43	--	--	--	--
	Ramona*	361	26	588	--	--
	Rincon	875	1	--	--	--
	San Miguelito	249	26	588	--	--
	Santa Clara Avenue	42	1	88	--	--
	Santa Paula	121	13	295	--	--
	Santa Susana	36	--	--	--	--
	Saticoy	139	--	--	--	--
	Sespe	1,098	98	2,206	--	--
	Shiells Canyon	190	--	--	--	--
	Simi	165	--	--	--	--
	South Mountain	1924	67	1,587	--	--
	Tapo Canyon, South	83	13	2	6	41
	Tapo Canyon, North	17	--	--	--	--
	Tapo Ridge	5	--	--	--	--
	Temescal	67	--	--	--	--
	Timber Canyon	97	--	--	--	--
	Torrey Canyon	219	3	294	--	--
	Ventura	1939	98	2,206	--	--
	West Mountain	106	--	30	--	--
	Subtotal	9,725	436	9,883	6	41
	(Gas Plants)					
	Montalvo, West	245	263	82	--	83
	Ojai	163	176	55	--	55
	Santa Clara	699	750	235	--	236
	Ventura	493	530	166	--	166
	Subtotal	1,600	1,719	538		540
	Rincon Onshore Facility	593	14	1,233		
	COUNTY TOTAL	11.918	2,169	11,654	6	581

*Fields in more than one county.

NOTE: Dash represents no emissions or less than one metric ton/year.

TABLE 1.4-2. COMPARISON OF SOUTH COAST AIR BASIN OIL PRODUCTION EMISSIONS TO THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT DRAFT 1979 EMISSION INVENTORY

	Emissions (thousand metric tons/yr)				
	THC	CO	NO_x	SO_x	Particulates
Total Stationary Sources[1]	783	198	146	70	175
Petroleum Production[2]	28	36	4.9	1.4	0.1
Petroleum Production Percentage	3.6	18.2	3.4	2.0	0.06

[1] Source: Annual Report For 1980 on The South Coast Air Quality Management Plan, South Coast Air Quality Management District, September, 1981.

[2] Source: South Coast Air Basin emissions estimated by this program.

TABLE 1.4-3. POLLUTANT EMISSIONS FROM DRILLING RIGS IN 1979

		(Metric Tons/Yr)				
		NO_x	SO_x	CO	THC	Particulates
San Joaquin Valley						
	Diesel	331	22	72	26	24
	Gas	59	(a)	7	24	NA(b)
Coastal Area						
	Diesel	111	7	24	9	8
	Gas	38	(a)	5	16	NA(b)
Los Angeles Basin						
	Diesel	53	4	12	4	4
	Gas	8	(a)	1	3	NA(b)
		600	33	121	82	36

Emission Factor Source: AP-42 Tables 3.3.2-1 and 3.3.3-1

(a) Less than one metric ton

(b) Emission factor not available in AP-42 whether the rig is "making hole" or performing some other operation. The approach used by KVB was to plot the fuel used per day and the days required to drill for various depth wells in the San Joaquin Valley, Coastal Area, and the Los Angeles Basin. This integrated the many cycle fluctuations involved in drilling a well.

To calculate emissions it was necessary to first determine the average depth well drilled in each region. From that the total amount of equivalent diesel fuel required could be found from the graphs of fuel per day and time required versus depth. This was apportioned into diesel fuel and natural gas using the horsepower ratios of the rigs located in each region. A correction was also made for electrically driven rigs. The emissions were then calculated using AP-42 emission factors.

Steam enhanced oil recovery well vents have been found to be significant sources of hydrocarbons. These emissions can be controlled through the use of centralized vapor recovery systems, however, in many locations there is no control system used. Using recently published data, prepared by Radian for EPA (Ref. 3), KVB has analyzed the VOC emissions resulting from these well vents on a field-by-field basis. These emissions are reported separately and were not included in the computer program as VOC's were not compatible with the computer program and the emissions data became available after the computer program had been written. The emissions are summarized in Table 1.4-4. They are presented in greater detail in Section 5.0.

During test phase of this program, KVB found wide variations in engine operating conditions and emission levels of CO, NO_x, and THC. The findings suggest that there is no single correlation between the emission levels and any specific operating parameter. However, using the results from testing 22 IC engines, a set of overall emission factors was developed. These are presented in Table 1.4-5.

Tests conducted on eight oil field heaters and heater treaters indicate that NO_x emission levels are low. The test results also showed that the levels of CO, THC and carbon (Bacharach Smoke Spot Number) could be quite high

TABLE 1.4-4. WELL VENT VOC EMISSIONS FROM STEAM ENHANCED CRUDE OIL PRODUCTION WELLS

County	Field	VOC Emissions Metric Tons/yr
Fresno	Coalinga	6,390
Monterey	San Ardo	36
Santa Barbara	Cat Canyon	0
	Santa Maria Valley	39
	Casmalia	0
San Luis Obispo	Guadalupe	0
	Arroyo Grande	0
Orange	Yorba Linda	9,110
	Huntington Beach	46
	Brea-Olinda	1
	Newport, West	2
Ventura	Shiells Canyon	69
	Oxnard	1
	Tapo Canyon, South	1
Kern	Belridge, South	56,500
	Cymric	317
	Edison	333
	Fruitvale	2
	Kern Bluff	18
	Kern Front	1,470
	Kern Front/Poso	15
	Kern River	24,700
	Lost Hills	285
	McKittrick	2,250
	Midway Sunset	23,300
	Mount Poso	9,380
	Poso Creek	54
	Temblor Valley	2
	Belgian Anticline	1
	Buena Vista	1
	Railroad Gap	1
	Tejon	1
	Wheeler Ridge	1
	Edison, Northeast	4
Los Angeles	Placerita	1
	Wilmington	1

TABLE 1.4-5. EMISSION FACTORS FOR GAS-FIRED INTERNAL COMBUSTION ENGINES FOUND IN CALIFORNIA OIL FIELDS*

	Nitrogen Oxides (as NO_2)		Carbon Monoxide		Hydrocarbons as CH_4		Hydrocarbons as TOC		Sulfur Dioxide†
	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	Estimated
Internal Combustion Engines									
$\leq$ 100 HP									
ppm, dry @ 15% O_2	180	36-389	3100	148-8800	450	3.0-1720	1400	218-2200	0.096
lb/hr§	0.35	0.051-0.81	3.3	0.19-9.3	0.32	0.0020-1.2	0.51	0.11-1.1	0.00024
grams/HP-hr	6.6	0.88-18	74	4.2-230	7.9	0.047-28	13	1.7-27	0.0051
lbs/MMBtu	0.71	0.20-1.6	9.2	0.41-27	0.70	0.0042-2.2	1.1	0.23-2.1	0.00053
lbs/M bbl. gross production	240	16-730	3100	180-17,000	39	1.9-110	260	110-520	0.18
ng/J	310	86-690	4000	180-11,600	300	1.8-930	470	100-1000	0.23
100-300 HP									
ppm, dry @ 15% O_2	140	12-628	8800	136-20,000	660	0.62-3300	1300	413-4500	0.11
lb/hr§	0.28	0.026-0.81	15	0.31-30	0.39	0.00052-1.9	0.67	0.37-1.9	0.00040
grams/HP-hr	4.0	0.28-19	150	14-270	6.1	0.0057-23	8.8	2.3-24	0.0040
lbs/MMBtu	0.51	0.042-2.2	18	0.32-40	0.79	0.00064-3.9	1.1	0.34-4.0	0.00054
lbs/M bbl. gross production	57	2.6-160	4000	79-17,000	29	0.43-66	130	20-370	0.088
ng/J	220	18-950	7700	140-17,200	340	0.28-1700	470	150-1700	0.23
Weighted Composite $\leq$100 HP 100-300 HP									
ppm, dry @ 15% O_2	170	12-628	5200	136-20,000	560	0.62-3300	1300	218-4500	0.10
lb/hr§	0.32	0.026-0.81	8.0	0.19-30	0.36	0.00052-1.9	0.60	0.11-1.9	0.00030
grams/HP-hr	5.6	0.28-19	102	4.2-270	6.9	0.0057-28	11	1.7-27	0.0047
lbs/MM Btu	0.64	0.042-2.2	13	0.32-40	0.75	0.00064-3.9	1.1	0.23-4.0	0.0053
lbs/M bbl. gross production	170	2.6-730	3400	79-17,000	33	0.43-110	190	20-520	0.14
ng/J	270	18-950	5500	140-17,200	320	0.28-1700	470	100-1700	0.23

*Results based on tests run on 22 gas-fired internal combustion engines; eight have HP ratings >100 HP, and 14 have HP ratings $\leq$100 HP. Average engine load measured was 37%, HP 88. Tests occurred at three different oil fields in the South Coast Air Basin. Fuel used was either natural gas or processed field gas.

†Based on a typical natural gas sulfur content of 2000 grains per 10^6 scf as reported in AP-42, Section 1.4.1.

§Even though lbs/hr is an emission rate and not an emission factor, it is provided here for convenience.

due to either a combustion air excess or deficiency resulting from poor tuning or partially plugged air inlets. Composite emission factors for the eight heaters are presented in Table 1.4-6.

1.5 CONCLUSIONS

This program has resulted in a comprehensive emission inventory for the oil production industry in California for the year 1979. In addition, a computerized emissions data base has been compiled which, with the developed methodology, can be updated annually.

1.6 RECOMMENDATIONS

For the most part, housekeeping at the sites which were visited was relatively good and at several sites it was impressive. There were some sites which were in need of cleanup and valve and fitting maintenance. Oil leaks and spills and poorly maintained piping and equipment contribute significantly to fugitive hydrocarbon emissions. Valve and fitting maintenance requirements developed jointly by the oil industry and the air regulatory agencies and the sump and pit reduction program conducted by the Division of Oil and Gas should significantly reduce fugitive emissions. Additionally, general housekeeping and maintenance of equipment such as tanks needs to be encouraged. Well vents currenty release large amounts of VOC emissions. These quantities will increase as the use of thermally enhanced production increases. These emissions should be controlled both from an air quality and a product loss standpoint.

There is a lack of comprehensive test derived emission factors for valves, fittings and other components associated with heavy oil production. Heavy oil production is growing in California due to improved recovery technology and a changing economic climate. Hence, an emissions testing program similar to that conducted by Rockwell for API should be performed to establish emissions data for equipment associated with heavy oil production.

Shortcuts were used in this program to estimate emissions from tanks and sumps because data and methodologies required to perform more specific estimates of these emissions are not available at this time. While tanks are

TABLE 1.4-6. EMISSION FACTORS FOR GAS-FIRED OIL-FIELD-TYPE HEATERS AND HEATER-TREATERS FOUND IN CALIFORNIA OIL FIELDS

	Nitrogen Oxides (as NO_2)		Carbon Monoxide		Hydrocarbons as CH_4		Hydrocarbons as TOC		Sulfur Dioxide††
	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	Estimated
Heater-Treater* Direct Fired 3-5 MMBtu/hr burner size									
ppm, dry @ 3% O_2	43	21-77	2200	47-8700	864	neg.-3900	1070	1.70-6300	neg.
ng/J	24	11.6-45	760	17.2-23,000	125	neg.-700	150	0.25-900	0.26
lbs/MMBtu**	0.056	0.027-0.104	1.76	0.040-7.3	0.29	neg.-1.63	0.35	0.00057-2.1	0.0006
Heater-Treater† Pilot Light Only 3-5 MMBtu/hr burner size									
ppm, dry @ 3% O_2	88	75-107	37,000	120-80,000	18,600	1250-39,000	37,000	1230-76,000	neg.
ng/J	41	17.2-65	5600	45-11,200	1680	260-3100	2400	189-4600	0.26
lbs/MMBtu	0.096	0.04-0.152	13	0.104-26	3.9	0.60-7.2	5.5	0.44-10.6	0.0006
Small Heaters - Indirect Fired§ 500,000 Btu/hr size Stack Gas Composition @ ~80% F.R.									
ppm, dry @ 3% O_2	52	29-77	12,400	60,000-77	59	0.5-107	79	4.7-132	neg.
ng/J	26	8.6-41	2400	25-11,200	9.0	0.099-19.4	9.0	0.65-18.1	0.26
lbs/MMBtu	0.060	0.020-0.096	5.5	0.058-26	0.021	0.00023-0.045	0.021	0.00151-0.042	0.0006
Small Heaters - Direct Fired# 500,000 Btu/hr size "Propane Fuel" Stack Gas Composition @ ~60% F.R.									
ppm, dry @ 3% O_2	47		290		62		1130		neg.
ng/J	32		12.0		14.2		198		0.26
lbs/MMBtu	0.074		0.028		0.033		0.46		0.0006

*Results indicate average emission factors developed from the testing of two 6-MMBtu/hr total, one 10-MMBtu/hr total, and one 8-MMBtu/hr total dual burner/firetube horizontal crude oil (oil-water emulsion) heaters. Fourteen tests on 6 burners over a firing rate range of 20% to 80% of capacity were performed. Fuel was either processed field or natural gas.

†Pilot light tests were performed on each burner of a dual burner heater.

§Results indicate average emission factors developed from the testing of two 500,000-Btu/hr single burner/firetube horizontal crude oil heater-treater and one 348,000 Btu/hr single burner/firetube, glycol reboiler. Five tests at approximately 40 to 80% load were performed. Fuel was processed field gas.

#Results based on the data obtained from one test performed at approximately 50% load. Heater is rated at 500,000 Btu/hr, fired on LPG, and of a single burner.

**Based on a HHV of approximately 1,000 Btu/scf.

††Based on a typical natural gas sulfur content of 2,000 grains per 10^6 scf as reported in AP-42, Section 1.4.1.

a significant source of hydrocarbon emissions, adequate emissions estimating methods have not been developed so that emissions can be accurately assessed for even a single tank. This is considered a major research area which needs to be pursued by both regulatory agencies and industry.

It is recommended that the methodology and data base developed during this program be adopted as a foundation for future work.

SECTION 2.0

PLANNING AND INTERFACING

In conducting a program of this magnitude with a limited budget, planning, site selection, and coordination are extremely critical. First, the sites to be inventoried and tested had to be selected. They had to be sufficient in number and possess the desired process characteristics such that a complete picture of production operations could be created. Once the sites were selected it was necessary to obtain approval from owners or operators to survey and test their facilities.

2.1 OIL FIELD AND LEASE CATEGORIZATION

Since it was not possible to visit the over 200 oil fields in the state and perform detailed inventories of valves, fittings, pumps, tanks, etc. it was necessary to characterize the oil fields into appropriate groups or classifications. From each group a representative field was selected to be inventoried. This approach provided data on a broad spectrum of production methods and field characteristics. The actual field inventory and data analysis was conducted on a lease basis.

A lease base inventory approach was used. This was a procedural refinement that provided increased accuracy over a field base inventory since often there are greater differences between leases within the same field than between fields themselves. For example, in certain well-established fields, major oil companies have installed unitized production operations on one or more leases while in the same fields, many small (one to five wells) production operations exist which bear little resemblance to those larger operations in terms of numbers and types of valves and fittings, tankage, and other surface equipment. Tankage for processing and storage of crude oil is usually associated with leases rather than fields or even areas of fields and the large emissions associated with them.

Data used to select the parametric field groupings came from the 1977 Annual Report of the California Division of Oil and Gas, Volumes I and II of the California Division of Oil and Gas Report TR-12, Maps and Data Sheets, and the 1978 Annual Review of the Conservation Committee of California Oil Producers. In analyzing these data it was determined that the primary parameters having a bearing on the type and amount of surface equipment found in the field were as follows: (a) the number of wells, (b) depth of the producing zone, and (c) the production rate of oil, gas, and water. The gravity of the oil, originally considered in this list, was found to be too much of a variable to be used for grouping. Other parameters considered for categorization, but abandoned included zone age, type of production, terrain, operators, well spacing, and geographic location.

The number of wells in a field vary from a field with a single well to Midway Sunset which has on the order of 6900 wells. The fields were categorized into three general classes; those fields with less than 10 wells, 10 to 75 wells, and over 75 wells. It was felt that 10 wells and 75 wells would be logical thresholds for the appearance and variations in surface equipment such as tanks, shipping equipment, heater treaters, gas/oil separators, etc.

The depth of the producing zone was specified as shallow, medium and deep with shallow being less than 2500 feet, medium 2500 to 7500 feet, and deep greater than 7500 feet. Since production in a field can be from different pools, many fields produce from an extensive range of depths. Thus, a given field can be listed as shallow to medium or medium to deep. Most fields in California are in the shallow or medium range. The depth has more impact on the method of extraction or production and energy needed to raise the oil to the surface than it does on surface equipment.

Production rate is expressed as barrels of oil per day per well. This is generally a rather low figure for most California fields with most fields producing less than 20 barrels per day per well. Gas-oil-ratio (GOR) refers to the cubic feet of gas produced per barrel of oil. GOR was rated as low, medium, or high with 400 cf/bbl as the threshold from low to medium and

1000 cf/bbl taken to be the threshold from medium to high. "Cut" is the percentage of total fluid produced (oil and water) which is water. The cut in California fields is generally high. It is not uncommon to see cuts reported as over 90 percent.

Referring to Table 2.1-1 it can be seen that the final field grouping resulted in 12 onshore categories and three offshore categories.

Big Mountain was chosen as the representative Group A survey field. It is a four-well field in Ventura County with depth ranging from 3600 to 6200 feet and produces 35 b/d/w with a GOR of 1200 cf/bbl and a cut of 33 percent. This field, as are most in the group, is less than 20 years old.

The representative Group B survey field is Pyramid Hills which produces 3 b/d/w from 75 wells ranging in depth from 650 to 2800 feet. The GOR is 1800 cf/bbl and the cut is 79 percent. The field is located in Fresno and Kings Counties. There are 23 fields in Group B which were generally discovered in the 1940's and appear throughout most of California's producing regions.

Group C includes 18 large fields which are generally 25 to 40 years old. Many of the fields are undergoing water flood and it is common to have continual well remedial work. The Lompoc field in Santa Barbara County was chosen as the survey field for this group. It contains 111 wells, the depth is 2250 feet, production is 8 b/d/w, and GOR and cut are 2100 cf/bbl and 98 percent.

The Group D fields have been developed fairly recently. This probably accounts for the higher production rates. Several of these fields are in a belt extending from downtown Los Angeles to Westwood. One of the fields in the belt, San Vincente, was chosen as the survey field for the study. It has 33 wells at a depth of 2000 to 4200 feet and produces an average 63 b/d/w. The gas-oil ratio is 900 cf/bbl and the cut is 60 percent.

Groups E, F, and G share the common characteristics of shallow to medium depth range, less than 30 b/d/w production, a low GOR, and a high cut. The only differentiation is the number of wells per field. The fields in Group E which is the smallest of the three groups are generally from 20 to

TABLE 2.1-1. OIL FIELD CATEGORIES AND CHARACTERISTICS

Category	# Of Fields†	# Of Wells	Depth (Feet)	Rate (bbl/day)	GOR (ft^3/bbl)	Cut % Water
A	7	<10	S-M	20	High	High
B	23	10 - 75	S-M	20	High	High
C	18	>75	S-M	20	High	High
D	7	10 - 75	S-M	20-75	High	High
E	23	<10	S-M	30	Low	High
F	21	>75	S-M	30	Low	High
G	27	10 - 75	S-M	30	Low	High
H	20	>75	S-M+	35	Med	High
I	17	30	S	35	Low	Low
J	12	< 10	6500 +	Varies	Varies	Varies
K	25	10 - 100	6500 +	Varies	Varies	Varies
L*	20	Varies	M-D	30	High	High
Oil Is's	3 (7)§	Varies	Varies	Varies	Varies	Varies
1st Gen. Pltf's	4(11)	Varies	Varies	Varies	Varies	Varies
2nd Gen. Pltf's	2 (5)	Varies	Varies	Varies	Varies	Varies

* Stevens Zone
† Excludes Tertiary Recovery Field
§ Number of Islands or Platforms Indicated in Parenthesis

40 years old. The Union Avenue field in Bakersfield was chosen as the survey field for this category. It has two wells producing at depths of 4000 and 5000 feet, no gas and a cut of 95 percent. The production averages 27 b/d/w.

Group F is for large fields with over 75 wells. Many of the 21 fields in this category are being water flooded or have thermal operations underway. These fields are older as most were discovered in the 1920's. The Long Beach field is the selected representative for this group. It has 547 wells at depths of 4000 to 5200 feet, produces at 13 b/d/w, has a GOR of 440 cf/bbl and a cut of 95 percent. Three large water flood projects are underway in this field.

The Group G fields have 10 to 75 wells, shallow to medium depth and produce less than 30 b/d/w with low GOR and a high cut. These fields were developed from 1882 to 1963. The representative field for this group is the South Tapo Canyon field in Ventura County. The field characteristics are 14 wells, 1800 to 2200 feet depth, 9 b/d/w production rate, GOR of 110 cf/bbl and a cut of 84 percent.

The H group has 20 large fields with shallow to medium depth range, less than 35 b/d/w production, a medium GOR and a high cut. These fields are also old. Most were discovered in the 1920's. Almost all of these fields have water flood or steam flooding to enhance production. The field chosen as representative for this group is Cymric in Kern County. It has 778 wells producing 12 b/d/w from depths of 1200 to 8750 feet. The GOR is 730 cf/bbl and the cut is 85 percent.

Group I is limited to shallow wells with under 30 wells per field, low GOR and low cut. The production is less than 20 b/d/w. Most of these fields are 25 to 30 years old. The representative field chosen was Whitewolf, which is in Kern County. It contains eight wells producing 9 b/d/w from depths of 800 to 2800 feet. There is no gas and the cut is 25 percent.

Group J covers fields which produce from greater than 6500 feet. Most of the other characteristics vary widely. This is a large group which contains 37 fields. These fields are generally the newer fields in the state. The group was subdivided so that fields with more than 10 wells and less than

10 wells could be assessed. East Rosecrans was used as the representative under 10 well field. It has two wells producing 8 b/d/w at depths of 5800 to 7500 feet. The GOR is 1200 cf/bbl and the cut is 33 percent. The other subgroup is represented by two fields. The Yolumne field in Kern County has 40+ wells at a depth of 11,000 feet, a GOR of 1200 cf/bbl and a cut of 4 percent. It produces an average 410 b/d/w. The other field is Santa Clara in Ventura County. It has 11 wells producing 99 b/d/w from depths of 7400 to 8600 feet. The GOR is 520 cf/bbl and the cut is 27 percent.

There is a group for Stevens Zone production containing 20 fields. These fields are all in Kern County and produce from intervals within a thick section of the Stevens Zone. The ages of these fields vary from 5 to 40 years. Canfield Ranch, the selected representative, has 83 wells producing 18 b/d/w at depths of 7900 to 8900 feet. The GOR is 1200 cf/bbl and the cut is 80 percent.

Offshore operations are divided into oil islands, first generation platforms and second generation platforms. Those fields with locations onshore for drilling and producing from the tidelands are considered onshore fields. The representative first generation platform is Hilda. It is considered typical of most of the early platforms found in state waters. Union's Platform C represents the second generation group being installed in federal waters and planned for state waters. Rincon island, which is considered a typical offshore island, represents that group.

A mid-course program modification was to expand the scope of the study to include tertiary recovery fields and operations in addition to primary and secondary fields. This change allowed the study to provide a more complete picture of California oil production operations.

The computer program developed for this project was written for 12 lease models. The distribution of these models is shown in Table 2.1-2. Ten of the models were used for actual leases while two of the available models

TABLE 2.1-2. LEASE MODELS

1.	One and two well leases
2.	3 - 10 well leases with gas
3.	3 - 10 well leases without significant gas
4.	Leases with over 10 wells without significant gas.
5.	Unitized operations
6.	Leases with over 10 wells and gas
7.	Oil islands
8.	First-generation platforms
9.	Second-generation platforms
10.	Kern River - Getty
11.	Onshore receiving facilities
12.	Gas plants

were assigned to special production categories which were found to have significant emissions.

The first of these special categories was assigned to gas plants. These are large gas treatment facilities which may be associated with a single field or may receive gas from several oil fields and even some dry gas wells or fields. There are 26 major gas plants in the eight counties studied. These gas plants were not in the original scope of work. However, at the request of the Air Resources Board four facilities were surveyed and a model was developed.

The second of the special categories was "onshore facilities." These are the oil and gas treatment facilities which receive crude oil and gas produced by the offshore platforms. There are only two such facilities: Mobil's Rincon and Chevron USA's Carpinteria. However, the emissions potential from each facility was considered to be significant so a separate source category was established. The Mobil facility was inventoried to establish the model for this category.

One of the lease models was assigned to a specialized field operation that could not be matched or extrapolated to any other in the state. That was Getty's Kern River Field facilities outside Bakersfield. Getty has some 3,500 steam flood and cyclic steam wells in the Kern River Field, each pumping to uniform Automatic Well Test (AWT) manifolds and then to a huge centralized treatment, storage and Lease Automatic Custody Transfer (LACT) facility. In addition, Getty's production from the surrounding fields such as Kern Front is pumped to this centralized facility for treatment, storage and transfer via the LACT unit. This is an operation which is unique in both size and complexity and required that it be modeled separately.

The remaining nine model assignments were more conventional and reflected the major trends (GOR and number of wells) which were observed during the oil field survey and inventory portion of the program. The oil islands, first generation platforms and second generation platforms were retained from the original field grouping. These were actually lease models from the start as oil islands such as Arco's Rincon Offshore Facility or the

THUMS Islands off Long Beach are components of larger fields as are the production platforms off the coast.

Generally, a gas/oil ratio (GOR) of 500 was used as the determination of whether significant gas was produced. This appeared to be the most appropriate demarcation level as indicated by data contained in the annual DOG report (Ref. 6). There were some exceptions as a few older fields with relatively low GOR still maintain operating gas plants.

2.2 DRILLING, WORKOVER, AND WELDING EQUIPMENT

This task was to generate the emissions associated with drilling, workover, and welding operations.

The methodology used was to determine the number and characteristics of the rigs, the extent and character of use and their spatial location. Once the rigs had been inventoried and categorized, emission factors could be applied to obtain a spatial distribution of emissions for each source type.

2.2.1 Data Acquisition

Sources of emission data searched included computerized literature files, published reports, periodicals, and AP-42.

The drilling rigs are identified and located using Munger's Friday Reports and the Rig Locators published by Petroleum Engineer Magazine. The rig power plants and fuel type are identified in the Rig Locator. Trade publications such as the Munger Reports and the Faust Directory identify the companies, company contacts and trade associations.

The Daily Munger Reports, Annual Munger Report and the Annual Report of the State Oil and Gas Supervisor give the spatial distribution of drilling activities.

It was difficult to assess drilling activity on a strictly field-by-field basis since much of the drilling activity occurs outside defined fields or even away from known oil producing areas. Thus, it was more meaningful to define drilling activities on a broader geographical base which included the San Joaquin Valley, Coastal Area, and the Los Angeles Basin. Further, the area basis for drilling activity analysis dampens out variances in year-to-year drilling activities which might occur in any given oil field. Variances in drilling activity do occur even on an area-wide basis, but emissions calculated on that basis will more correctly define the significance of overall drilling activity. During the course of drilling a well, the drilling rig, and hence the rig's power plant, operates in many modes from shutdown, to idle, to full power. Further, the power required to make hole, pump mud and remove cuttings varies with the formation and generally increases with depth. These parameters were averaged since annual, and not instantaneous, emissions were being assessed. Hence, it was decided that a survey would be performed to determine the fuel consumption and days on stream required for various depths in each of the three drilling regions.

Questionnaires were sent to over 30 drilling contractors in the state to obtain the information. Each contractor was contacted by phone to discuss the questionnaire. The response was less than that necessary to complete the analysis. In July, 1980 the Western Oil and Gas Association requested that KVB attend a meeting in Bakersfield to determine what information was necessary for the survey and how they could assist in obtaining the information. As a result of the information supplied by WOGA and Chevron, USA, KVB was able to complete the drilling emissions survey.

The spatial distribution and activities of workover rigs and welding units are not published in a journal or trade publication that could be identified. Workover and welding contractors were identified and located using the Faust Directory. Trade associations and manufacturers of welding equipment were also identified and located.

Originally, the same procedure as used for drilling rigs was used to determine the emissions for workover and welding rigs. This proved unsatisfactory. The initial task was to determine the number of rigs, their location, the percentage of time spent in the oil fields, the typical modes of operation and their rate of fuel consumption.

Unsuccessful contacts were made with welding associations such as American Welding Society and the National Electric Manufacturer Association to determine the number of welding rigs operating in oil fields. It was reported that this information is not available on an industry basis and that most of the welding rigs were operated by independent contractors who worked in other industries and worked in the fields as "moonlighters" going from field to field as needed.

The problem was the same for workover rigs. Their function is to clean out or work on a well to increase or restore production. This again is on a field to field basis and as with the welding rigs, an inordinate amount of time and effort was being expended in locating workover rigs and assessing their emissions. As part of a scope redefinition in which gas plants were added to the program, the emissions from workover and welding rigs were deleted from the program because of a lack of information on which to base an assessment.

2.3 FIELD TEST PLANNING

It was found that available emission factors for combustion-generated emissions from oil field-service IC engines and process heaters were marginal at best. When KVB performed a NO_x study for the American Petroleum Institute, we found a lack of any emission factor data in the engine and heater size range used for oil production. Most of the data were for much larger equipment such as found in refineries. Therefore, factors from typical oil-field IC engines and heater treaters had to be generated so that the emission contribution of these devices could be determined on a field, county, air basin and statewide basis.

The emission factors were obtained from a formal test program. KVB used one of its mobile combustion test laboratories and auxiliary equipment to test representative equipment in the Los Angeles and Orange County areas. The details of these tests are described in Section 3.0.

The informal test program centered around the use of gas detector tubes. These are small tubes of reagent which stain at different lengths when exposed to varying concentrations of specific gases. These tests were conducted during the early field surveys and also as an adjunct to the formal test program. Because the detector tubes provided inconsistent data, in this application the informal program results have not been reported.

2.3.1 Site Survey and Selection

Since the budget for testing was limited, the object of the program was to minimize time spent between test sites and maximize time spent in sampling and analysis. KVB performed a quick overview of IC engines and heater treaters and found that the belt of Southern California fields extending from the Huntington Beach field through the Wilmington Field would provide opportunities to test various size heaters, heater treaters, glycol reboilers, and IC engines used to power sucker rod pumps and hydraulic lift system pumps. The IC engines on the hydraulic lift systems were of interest since they operate at constant load. Thus, they do not undergo the power surges experienced by IC engines on sucker rod units as they cycle between a loaded condition and idle which occurs about 10 times per minute.

The specific units selected for testing were: (a) two small heaters, one large heater treater, a glycol reboiler, and a vertical propane field heater treater at Chevron's Huntington Beach facilities; (b) two heater treaters at Long Beach Oil Development Company's (LBOD) Wilmington facilities; (c) IC engines on sucker rod pumping units at Hellman Estate's Seal Beach facilities; (d) IC engines on Powerine Oil Company's hydraulic lift systems in the Wilmington field; and (e) one large line heater or heater treater and several IC engines on sucker rod pumping units at Aminoil's Huntington Beach facilities. The Powerine IC engines were of interest since several of them were identical models, had been purchased at the same time, and were in the same service on the same system under the same load. Since the engines had the same history, the testing program would provide information on the variation of emissions among similar engines.

2.3.2 Test Plan

During the formal test program, a slightly different approach was taken than originally proposed. The new approach involved testing a large number of devices without making any operational changes which required the continuous help of an oil company employee. The advantage of this approach is that by testing a large number of devices, a wide range of operating and emission characteristics could be documented in a minimum amount of time.

Actual test time would be minimized with the advantage of maximizing the results obtained. This was designed to meet the primary objective of the program and still allow the program to be conducted in a manner suitable to KVB and the companies involved.

Method 5 particulate tests were dropped from the program due to the inherent sampling problems associated with such equipment and because all of the devices tested burned either natural gas or processed field gas. Gas-fired devices are generally very low particulate emitters requiring long sampling times to assure adequate sample collection. The small diameter stacks (<6") and pulsating flue gas associated with each IC engine tested would have made testing very difficult and yielded questionable results. The absence of elevated test platforms and sample ports, extremely low flue gas velocities (<10 ft/sec), and continuous on-off operation would have made the testing of heaters and heater-treaters nearly impossible. The results obtained from such tests would have been questionable, at best. Bacharach smoke spot tests were substituted for the planned Method 5 tests.

2.4 API AND WOGA COORDINATION

A primary source of emission factor data for this study was the American Petroleum Institute (API) Fugitive Hydrocarbon Emissions From Petroleum Production Operations study conducted by Rockwell International (Ref. 1). In their study, Rockwell measured fugitive hydrocarbon emissions from 21 production facilities located in four geographic regions of the United States. Offshore as well as onshore facilities were included. A total of 174,000 components were screened and inventoried and 8,500 individual field measurements were made.

The study performed by Rockwell is one of the most comprehensive fugitive hydrocarbon emission factor generating programs. While some of the data presented for individual components have been challenged as being statistically weak, there are few piping or equipment fugitive hydrocarbon emission sources for which an emission factor cannot be obtained from their results.

One of KVB's goals in surveying California production sites was to expand the data base for oil fields, platforms and gas plants which have been surveyed and counted. Thus, KVB coordinated with Rockwell's project manager to ensure that there would be no duplication. While Rockwell personnel were not at liberty to provide any information before the release of their report by API, they were willing to discuss the mutual projects and provide guidance within the constraints placed on them.

Rockwell International was retained by the Western Oil & Gas Association to serve as the program monitor for KVB's activities. Their presence was most visible during the November 1979 field test program when Dr. Fred Lippman was assigned to observe and assess the quality of KVB's field test procedures.

SECTION 3.0

PROCEDURES

3.1 FIELD SURVEYS

3.1.1 Planning

Most of the fields which were surveyed were selected from the original oil field grouping prepared by a former director of the State Division of Oil and Gas (DOG), Mr. John Matthews, who served as a consultant to the KVB project staff. The surveyed fields are shown in Table 3.1-1. Several parameters were used to select the specific survey fields. The field most representative of the particular field category was selected. Where possible, this selection included at least one field in each of the eight study Counties (Monterey, San Luis Obispo, Santa Barbara, Ventura, Los Angeles, Orange, Kern, and Fresno).

Once the field selection was complete, a schedule for implementation of the survey program was prepared. First, two of the selected fields closest in proximity to KVB's offices (East Rosecrans and Big Mountain) were selected to start the survey program. These were two of the smaller fields inventoried which was fortuitous for the initial survey work. A day was allowed for each field so that the KVB field crew could train without being under the time pressure that would be encountered in a large field. The remainder of the survey schedule was established so that all fields in a given area could be completed in a single trip.

The remaining fields, gas plants and oil production sites from the primary production phase of the program were surveyed in the spring of 1980. Authorization to expand the program scope to include tertiary production sites was received and lease and production facilities in Kern County's Kern River, Kern Front and Cymric fields were surveyed in June 1981 to complete the field portion of the program.

TABLE 3.1-1. SURVEYED FIELDS[1]

Class	Field	County
A	Big Mountain	Ventura
B	Pyramid Hills	Fresno/Kings
C	Lompoc	Santa Barbara
D	San Vincente	Los Angeles
E	Union Avenue	Kern
F	Long Beach	Los Angeles
	Kern River	Kern
	Kern Front	Kern
G	South Tapo Canyon	Ventura
H	Cymric	Kern
I	Whitewolf	Kern
J-1	East Rosecrans	Los Angeles
J-2	Yowlumne	Kern
	Santa Clara	Ventura
Stevens	Canfield Ranch	Kern
	Rio Viejo	Kern
Oil Island	Rincon	Ventura
1st Generation	Hilda	Offshore
2nd Generation	Platform "C"	Offshore

[1] Lease assignments for surveyed leases in these fields are presented in Table 7.1-2.

3.1.2 Field Survey Preparation

Once a field was selected and scheduled for survey, KVB's principal investigator and John Matthews, project consultant, would decide how many and which leases would be surveyed. Parameters discussed included the mix of operators, lease sizes, gas production, terrain, field access, expected equipment, condition, method of extraction (sucker rod, down hole hydraulic pump, gas lift, etc.) and others. Leases were selected to provide an overall picture of production operations in each field.

The final preparation required for a site survey was to brief the KVB field crew about each site to be surveyed. The crew would study field maps, Division of Oil and Gas data and and any other information which might be pertinent. Matthews would brief the crew about the operators and their leases, types of production equipment, type of operation, terrain, spread of equipment, tank farms, and method of extraction. Following the briefing, a survey plan was prepared.

3.1.3 Conducting the Survey

Once the crew arrived at a lease, they would make an initial familiarization tour and revise the survey plan, if necessary. The inventory of a site is a detailed count of all valves and fittings by type and all ancillary surface production equipment such as pumps, compressors, boilers, heater treaters, tanks, pumps, well cellars, I.C. engines and flow meters. Condition of the equipment, nameplate data and any available operating characteristics were recorded. Inventory data from each site were recorded on one or more inventory record sheets shown in Figure 3.1-1 and 3.1-2. Tank data was recorded on a separate sheet shown in Figure 3.1-3. Another task was to sketch typical well heads and to draw a flow schematic for each site.

Generally, small leases such as those with one, two or three wells were inventoried in their entirety. Individual wells in larger leases and especially unitized operations, the oil islands and oil platform were inventoried until a definite trend or repetition could be established. Some sites such as Getty's Kern River facilities had a mix of well types. Steam flood and cyclic steam production wells were interspersed on the surface. Thus, it

KVB
A Research-Cottrell Company

Engineer ______________
Date ______________

VALVE AND FITTING INVENTORY SHEET

OPERATOR ______________
FIELD ______________
SYSTEM ______________
FLUID ______________

VALVES

Legend: / - Flanged Connections
† - Threaded Connections
‡ - Buried Connections

	Totals: Components, Flanged	Threaded		Connections
. Gate			X 3 =	
			X 3 =	
. Plug			X 3 =	
. Ball			X 3 =	
. Check			X 3 =	
. Flow Control			X =	
. Pressure Regulator			X =	
. Pressure Relief			X =	
. Butterfly			X =	
.			X =	
.			X =	
SUB-TOTAL				

FITTINGS

Legend: / Welded Connections
† Threaded Connections

	Welded	Threaded		
. Unions			X 3 =	
. Flanges			X =	
. Swagelok†			X =	
. Elbows†			X 2 =	
. Tees†			X 3 =	
. Coupling†			X 2 =	
.			X =	
.			X 1 =	
.Misc.#			X 1 =	
SUB-TOTAL				
TOTAL				

Single Threaded Random Fitting

COMMENTS:

Figure 3.1-1

Location: ____________________

____

Well I.D. ____________________

1 WELL INFO: Production Rate: Gross ______ bbl/day
: Net ______ bbl/day

Pumper Size ______ Rod Dia. ______

Stroke/Min ______ Tubing Pres. ______ psig

Stroke/Length ______ Casing Pres. ______ psig

Air Balance Cyl. ______

2 SUMP: Area ______ X ______ ft^2

Comment: ____________________

3 IC: (Gas/Oil Fired) Engine? Electric (Circle One)

___/___/___/___/___/___/___

Make Model Cycle Cyl S/N User # Age

Design HP ______, Actual HP ______, RPM ______

Fuel Consumption: ______ MCF/Day, or ______ Gal/Day

______ MCF/Day, or ______ Gal/Yr

Date of Last Tuneup ______

Stack, Temp. ______ °F, Dia. ______ In.

Intake Manifold Vacuum ______ In. Hg

4 VALVE & FITTING INVENTORY:

		Count		Fittings
Valves:	•Gate ______	______	X 3 =	______
	•Plug ______	______	X 3 =	______
	• ______	______	X 3 =	______
	• ______	______	X 3 =	______
	Sub-Total	______		______
Fittings -	Elbow ______	______	X 2	______
	Tee ______	______	X 3	______
	Union ______	______	X 3	______
	______	______	X 1	______
	Sub-Total	______		______
	TOTAL	______		______

AREA LAYOUT

1 • Well
2 • Sump
3 •Tank Farm
4 •Separator

WELL HEAD SKETCH

COMMENTS: ____________________

KVB 5810-12

Figure 3.1-2. Well Inventory Record Sheet

PETROLEUM STORAGE TANK and PRODUCT DATA

COMPANY: **LOCATION OF TANKS:** **DATE:**

TANK NUMBER OR DESIGNATION	TANK TYPE	TANK SHAPE	TANK CAPACITY (BBLS.)	DIMENSIONS		TYPE SHELL CONST.	COLOR PAINT OR INSULA. ON SHELL	TANK MECH. CONDIT.	TYPE OF ROOF	TYPE OF F.R. SEAL	PRESS. VENT SETTINGS	WHERE VENTED	REMARKS.	PRODUCT	VAPOR PRESSURE			FILL IN ONLY IF VAPOR PRESSURE DATA NOT AVAILABLE FOR PRODUCT			API GRAVITY	AVG. LIQUID BODY STORAGE TEMP ($^\circ F$)	MAX. LIQUID BODY STORAGE TEMP ($^\circ F$)	MAX. FILLING RATE (BBL/HR)	AVG THROUGHPUT (BBL/DAY)	TURN-OVER PER YEAR	AVG OUTAGE	
				DIAM. OR LENGTH (FT.)	HT. OR WIDTH (FT.)										EITHER RVP (LBS)	OR ABS. (PSIA)	AT TEMP ($^\circ F$)	FLASH PT ($^\circ F$)	IBP ($^\circ F$)	FBP ($^\circ F$)								

TANK TYPE

C = Fixed or Conerool
F = Floating Roof
P = Pressure

TANK SHAPE

VC = Vertical Cylind.
HC = Horiz. Cylind.
S = Spherical or Spheroidal
R = Rectangular

TYPE SHELL CONSTR.

W = Welded
R = Riveted
RG = Riveted and Gunited
B = Bolted

TYPE OF ROOF

C = Fixed or Cone
W = Water Seal
O = No Roof, Open Top
D = Doubledeck F.R.
P = Pontoon F.R.
PM. = Pan F.R. Modified
Pan = Pan F.R.

TYPE F.R. SEAL

O = No Seal
S = Single Seal
D = Double Seal
T = Tube Seal

COLOR PAINT OR INSULATION

CW = Chalking White
AL = Aluminum
LG = Light Gray
D = Dark Color, No Paint or Needs Repainting
IN = Insulated

TANK MECH. CONDITION

G = Good (vapor tight)
F = Fair (minor leakage)
P = Poor (needs repair)

WHERE VENTED

A = Atm.
V.R. = Vapor Recovery
V.D. = Vapor Disposal
V.B. = Vapor Balancing

REMARKS (EXAMPLES)

Micro Balloon
Equipped for Air Moving
Equipped with Heating Coils
Open Vents
Etc.

XXXIV

Figure 3.1-3

was necessary to establish a composite inventory for each type and find the ratio of each to the total number of wells.

It should be noted that KVB's inventory procedure differed from the way that the Rockwell conducted their inventory for the API (Ref. 1). KVB's approach was to inventory a gate valve as a gate valve with flanged or threaded connections. Rockwell's approach was to inventory the valve as three separate leak points which were the bonnet and the two flanges or threaded connections. Likewise, KVB recorded centrifugal pumps, compressors, etc. While Rockwell disassembled those devices into their individual components such as the shaft seal, head flanges and pipe connections.

The listing of connections on Figures 3.1-1 and 3.1-2 was included on the inventory sheets before any knowledge of Rockwell's data recording technique was available. KVB's intent was to inventory with as much flexibility as possible to facilitate adaptation to Rockwell's API report when it was issued. As it turned out, the KVB approach was consistent with Rockwell's approach for fittings, but not valves or other components. Therefore it was necessary to work out an accounting scheme to accommodate both the KVB and the Rockwell inventory procedures.

3.2 TYPES OF MEASUREMENTS MADE, EQUIPMENT USED, AND CALCULATIONS INVOLVED

A number of observations, measurements, and calculations were made to characterize the emissions from gas-fired I.C. engines, heaters, and heater-treaters in addition to conducting the general equipment inventory. A summary of the various types of information is presented below in Table 3.2-1. The gaseous species measured were O_2, CO, CO_2, NO, NO_x, SO_2, and THC as CH_4 and TOC. Carbon emissions were qualitively assessed in terms of smoke spot numbers. Fuel flow, air flow, and pollutant emission rates were determined by means of combustion calculations using the measured data. Presented below is a brief discussion of the different types of measurements made, the equipment used and, an example of the calculations involved in arriving at the final results, emission factors.

TABLE 3.2-1. TYPES OF MEASUREMENTS MADE AND EQUIPMENT USED

Type of Measurement	Equipment
O_2, CO, CO_2, NO-NO_x, and SO_2	KVB Mobile Test Van
Hydrocarbons (CH_4 and TOC)	Grab Samples
Particulate Emissions	Bacharach Smoke Spot Pump
Stack Gas Velocity	Standard Pitot Tube plus Thermocouple
Engine Load, % of rated Horsepower	Vacuum Guage

Parameters Calculated
Stack Gas Volumetric Flow Rate
Fuel Flow and Air Flow
Emission Factors and Rates

3.2.1 O_2, CO, CO_2, NO, NO_x and SO_2

A KVB mobile test van equipped with a portable electrical generator and continuous analyzers was used to accurately measure the concentrations of O_2, CO, CO_2, NO, NO_x and SO_2 in the flue gas. Flue gas samples were extracted from a single point in each stack and passed to the mobile van through a 50-ft-long heated Teflon sampling line. Total sample flow was approximately 1 scfm. The sample gas drawn off for the SO_2 and NO_x instruments was maintained at approximately 300°F prior to entering the instruments. The sample gas drawn off for the O_2, CO, CO_2 and NO instruments was passed through a refrigerated condenser to remove the water prior to entering the instruments.

The instruments used for the gas analysis are as follows:

O_2	Teledyne, Model 326A electrochemical
CO (2000 ppm)	Horiba, Model PIR 2000
CO_2	Horiba, Model PIR 2000
NO, NO_x	Thermo Electron, Model 10A Chemiluminescent
SO_2	Dupont Model 400
CO (2000 ppm)	Hayes-Republic Orsat Analyser

Each instrument was zeroed and span-checked prior to each test to assure its accuracy. The span gas used for each instrument contained a gas concentration of the measured species within or very near the range being measured. All span gases were certified by their supplier to be accurate within ±2 percent of the value written on the bottle. The ORSAT analyzer was used to measure CO concentrations above 2000 ppm since the upper limit of the Horiba CO analyzer was 2000 ppm.

3.2.2 Total Hydrocarbons

Hydrocarbon emissions were determined by taking grab samples of the flue gases and analyzing for methane (CH_4), CO, and total organic carbon (TOC). The grab samples were taken by pulling a volume of flue gas through double ended glass gas collecting bottles. Sample analysis was performed by Analytical Research Labs (ARLI) located in Monrovia, California.

The Total Hydrocarbon Analyzer used by ARLI was also designed and fabricated by ARLI. The design of this instrument is in full conformance with the reference method promulgated by the EPA (Federal Register, 36, 22394-22396 (Nov. 25, 1971)). The analyzer provides fixed volume inlet system, a vacuum system for inter-connecting line purging, a pressure gauge to measure the actual pressure of the sample injected and a low volume stainless line connected to an FID. The signal from the FID is recorded on a 10-inch Honeywell Brown Electronik strip chart recorder. The Total Hydrocarbon Analyzer (TOC Analyzer) is also capable of determining carbon monoxide and methane content in gases. By proper valving, the sample is directed through a GC column and into a Sabatier methanator with a stream of hydrogen. Methane, if present, elutes from the column, proceeds through the methanator unchanged and then to the FID and is recorded. Shortly afterward the CO elutes from the column to the methanator where it is converted to methane and recorded. This second methane peak is calculated as carbon monoxide in the original sample. The first methane peak is used for actual methane measurements. The methane value thus obtained is subtracted from the total hydrocarbon value to give nonmethane hydrocarbons (nmhc). The Total Hydrocarbon Analyzer was calibrated before each series of analyses using a 45 ppm hexane gas standard.

3.2.3 Carbon Emissions

The emission of carbon particles from combustion devices was semi-qualitatively assessed using a instrument known as a Bacharach smoke spot pump (see Figure 3.2-1). Using this instrument, a test smoke spot is obtained by pulling a fixed volume of flue gas through a fixed area of standard filter paper. The color (or shade) of the spot produced is then visually compared with a standard scale of varying smoke densities. The test result is reported as the "Smoke Spot Number" which is the number of the spot on the standard scale most closely matching the color (or shade) of the test spot.

The standard smoke scale consists of ten spots numbered consecutively from 0 to 9, an example of which is reproduced in Figure 3.2-2. These ten spots range in equal photometric steps from white through neutral gray to black and are normally imprinted or processed on white paper or plastic stock having an absolute surface reflectance of betweeen 82.5 and 87.5 percent

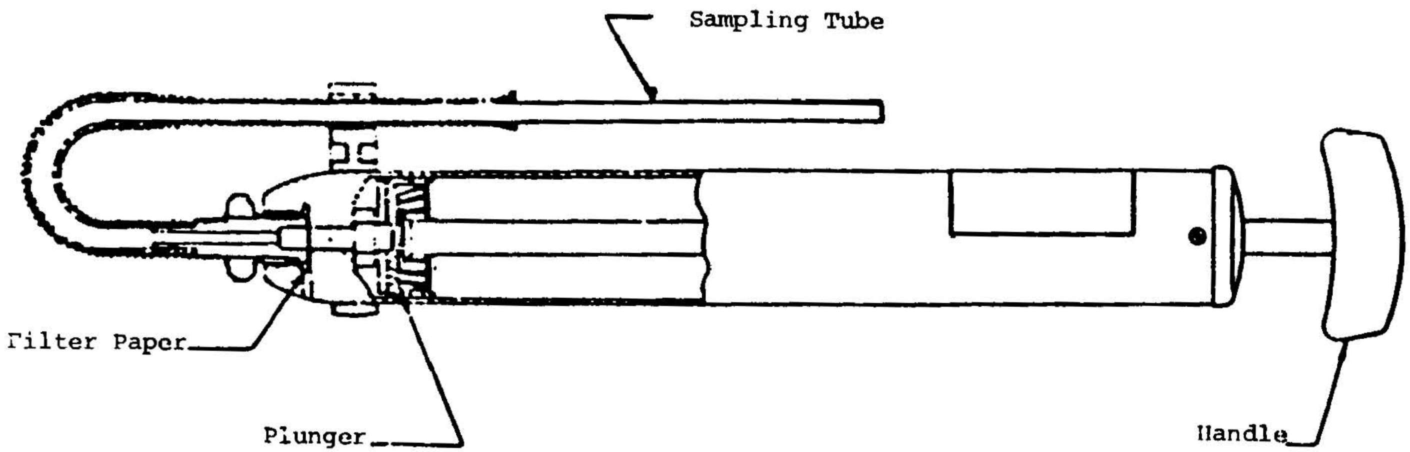

Figure 3.2.1. Typical Bacharach field type of smoke spot pump.

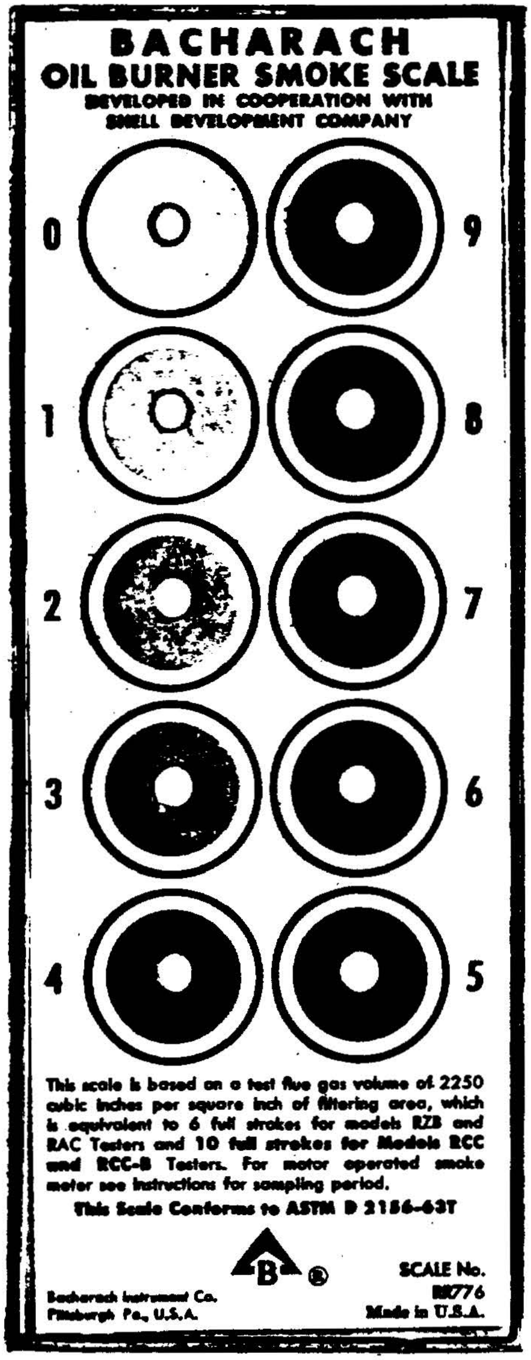

Figure 3.2-2. Reproduction of a Bacharach smoke spot scale.

determined photometrically. The smoke scale spot number is defined as the reduction (due to smoke) in reflected incident light directed thereon.

The Bacharach smoke spot pump offers an expeditious field method for evaluating the qualitative emission of carbon particles from gas- and light oil-fired combustion equipment. To date, there has been no widely accepted correlation between smoke spot numbers and mass emission rates, and consequently, the instrument can not be used for obtaining quantitative values. The Bacharach smoke spot pump is a ASTM approved method (Ref. 7) for evaluating the smoke densities in flue gases of distillate oil-fired burners. The instrument is also used in the same capacity by many combustion engineers in analyzing the performance of gas-fired equipment.

3.2.4 Stack Gas Velocity

Flue gas velocities were determined by means of a standard type pitot, differential pressure inclined manometer, and type "K" thermocouple plus digital readout. A minimum of three sample points located at 16.7, 50.0, and 83.3 percent of the stack diameter were taken in accordance with the requirements of EPA's proposed Method 20 for I.C. engines. The diameter of the temporary stacks used on the I.C. engines tested measured from 3 to 4-1/2 inches (internal diameter). The stacks permanently installed on the heaters and heater-treaters tested measured from 7 to 30 inches (internal diameter).

3.2.5 Engine Load, Percent of Rated Horsepower

An approved American Petroleum Institute (API) standard* for IC reciprocating engines for oil field service was followed to compute the load or horsepower of each engine tested. The procedure specified involves the measurement of an engine's intake manifold vacuum at two different operating conditions and then relating these data to a set of API-developed vacuum-vs.-load curves. The two operating conditions at which the intake manifold vacuum are measured are (1) no load - normal speed, and (2) normal loading - normal speed. A copy of the API standard, Appendix B, for oil field service I.C. engines is reproduced below in Figure 3.2-3.

---

*API specification for internal combustion reciprocating engines for oil field service, API Std. 7B - 11C.

B1. The recommendations given herein are for use on four cycle engines of two or more cylinders equipped with carburetors for liquid or gaseous fuels.

B2. The vacuum-load curves shown in Fig. B.1 are an index of the approximate percentage of power (within 3 per cent on new engines), that an average engine in proper adjustment will develop at a given location. These curves cannot be used on supercharged engines.

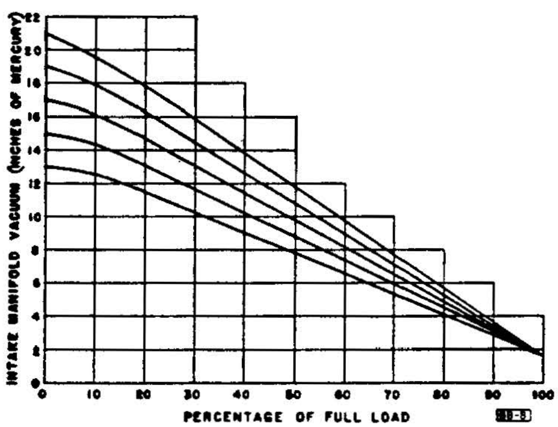

FIG. B.1
INTAKE VACUUM VS. LOAD CURVES

NOTE: *The curves shown in Fig. B.1 are the average of curves obtained from six representative engine manufacturers covering many models having cylinder bores varying from 2½ to 8 in.*

Instructions for Use

B3. The engine to be tested should be checked to make certain that it is properly adjusted before any vacuum readings are taken. The spark, gas supply, gas pressure, and carburetor should particularly be checked and any necessary adjustments made.

B4. A conventional vacuum gage with a dial graduated in inches of mercury should be used.

B5. The engine should be run at its normal operating speed with no load and a reading taken of the intake manifold vacuum.

½M—6-76
1M—9-77

B6. The engine should then be run at normal operating speed with its normal loading and a reading taken of the intake manifold vacuum.

B7. The curve should then be selected (see Fig. B.1) whose ordinate at no load most nearly corresponds to the intake manifold vacuum reading taken at no load for the engine being tested. From the intake manifold vacuum reading taken at normal loading, a point on this curve is located whose abscissa indicates the percentage of full load at which the engine is operating.

NOTE: *The manifold vacuum and horsepower that an engine will develop decrease with an increase in altitude. Engine manufacturers consider sea level barometric pressure (29.92 inches of mercury) as standard. The power developed by an engine decreases about 3 per cent with each 1000-ft. increase in altitude. Likewise the no load intake manifold vacuum decreases about 5 per cent for each 1000-ft. increase in altitude. For example, an engine that develops 20-in. vacuum at no load at sea level, will develop about 14-in. vacuum at 6000-ft. altitude.*

Example:

Test conditions:

a. Intake manifold vacuum at no load: 17 in. of mercury.
b. Intake manifold vacuum at normal loading: 10 in. of mercury.

Solution:

a. From Fig. B.1 select the curve which shows 17-in. vacuum at no load.
b. Follow down this curve to a point whose ordinate is 10-in. vacuum. Determine that the engine is developing 48 per cent of full power.

B8. Failure to duplicate former readings at no load and normal speed indicates poor engine condition due to poor gas supply, loss of compression, ignition timing, etc.

B9. Failure to duplicate former readings at normal load and speed indicates either a change in engine efficiency or a change in load.

B10. Field men should become familiar with the vacuum-curve readings taken when their engines are properly adjusted and in good operating condition in order to enable them to detect variations in either load or engine condition.

Figure 3.2-3. Recommended API practice for use of intake vacuum versus load curves for internal-combustion engines.

3.2.6 Calculations Used in Determining Air Flow, Fuel Flow and Emission Factors

The numerous combustion devices tested by KVB generally lacked any type of instrumentation commonly used by industry to monitor combustion air flow and fuel flow rates. The temporary installation of instrumentation to measure these fluid flow rates was considered impractical. Since these data were required to develop emission factors for each device tested, each fluid flow rate was calculated by indirect means based on available data.

Presented in Table 3.2-2 is a summary of the data which was measured, made available, or calculated. The measured data consisted of the items normally measured in any combustion field test; namely, flue gas composition, temperature, flow rate, and static pressure. With I.C. engines, the unit's intake manifold vacuum was also measured.

The data made available consisted of such items as a typical fuel analysis of the fuel being burned at the test site and a unit's design horsepower rating, if it was an I.C. engine, or design heat output (i.e., 10^6 Btu/hr output) if it was a heater or heater-treater.

The data calculated also consisted of items normally determined during any combustion field test, namely, flue gas volumetric flow rates, fuel flow rates, and emission factors for the pollutants studied.

From these data, numerous other parameters were calculated leading to the development of a unit's emission factor. Presented below is an example to illustrate this procedure for I.C. engines. The same basic procedure was also used for heaters and heater-treaters. Standard conditions used are 70°F and 1 atmosphere.

Combustion Device Tested

Waukesha Model 1817, 105 hp, gas-fired, four-stroke I.C. engine

Step 1. Data Measured

a. Flue gas composition:

10.1% CO_2, dry	200 ppm NO_x, dry
2.0% CO, dry	1930 ppm CH_4, dry
1.1% O_2, dry	3900 ppm TOC, dry

TABLE 3.2-2. SUMMARY OF THE DATA MEASURED, DATA MADE AVAILABLE, AND DATA CALCULATED

Data Measured	Data Made Available	Data Calculated
• Flue gas composition:	• Fuel gas analysis	• Flue Gas:
- CO_2, CO, O_2, NO_x, HC's @ CH_4 and TOC	• Engine design hp rating	- H_2O content - Molecular wt., wet & dry - Density
• Stack internal diameter	• Heater or heater-treater heat input rating	- % excess air - Velocity
• Stack gas velocity head, temperature and static pressure	• Barometric pressure	- Volumetric flow rate - Pounds dry flue gas per lb fuel
• Intake manifold vacuum		• Fuel gas flow rate
@ idle @ normal loading		• Combustion air flow rate
		• Engine load
		• Emission factors

b. Stack internal diameter - 4-1/4 in.

c. Stack gas velocity head, temperature, and static pressure:

0.12 in. ΔP average

629°F stack temperature (T_s)

+0.2 inches static pressure (P_s)

d. Intake manifold vacuum:

@ idle 20 in. Hg

@ normal load 15 - 15-1/2 in. Hg

Step 2. Data Made Available

a. Fuel gas analysis:

Mole %	Component
83.778	CH_4
4.245	C_2H_6
2.790	C_3H_8
1.154	$C_4H_{10}+$
0.085	O_2
0.670	N_2
7.278	CO_2
100	

Average M.W., 20.07 lb/lb mole

LHV, 914 Btu/scf

HHV, 1002 Btu/scf

Density, 0.0519 lb/scf

19.27 scf/lb

Stoichiometric A/F ratio, 14.09 lb air/lb fuel

Sulfur content, 2000 grains/10^6 scf

Moles of C/100 moles of fuel, 112.8

b. Engine design horsepower rating, 105

c. Barometric pressure (P_{bar}), 30.08 inch Hg

Step 3. Calculated Quantities

a. Flue gas composition:

	Dry
CO_2, %	10.1
CO, %	2.0
O_2, %	1.1
N_2, %	86.4
Trace Species	<0.4
	100%

H_2O content, 17.3%

Molecular wt. dry, 29.8 lb/lb-mole

wet, 27.8 lb/lb-mole

Density of flue gas referred to air wet, $\frac{27.79}{28.95} = 0.96\ (G_d)$

$$\%\ \text{Excess air} = 100 \times \frac{O_2 - CO/_2}{0.264\ N_2 - (O_2 - CO/_2)} = \approx 0.4\%$$

b. Stack gas velocity:

$$V_s = 2.9\sqrt{(\Delta P) \times \left(T_{s_{abs}}\right) \times \left(\frac{407}{P_s}\right) \times \left(\frac{1.00}{G_d}\right)}$$

$$= 2.9\sqrt{(0.12) \times (629 + 460) \times \left(\frac{407}{409 + 2}\right) \times \left(\frac{1.00}{0.96}\right)}$$

$$= 33.7 \approx 34\ \text{(ft/sec)}$$

where

$T_{s_{abs}} = T_s + 460$ $P_{s_{abs}} = (P_{bar} \times 13.6) + P_s$

$= 629 + 460$ $= 409 + 2$

$= 1089°R$ $= 411$ in.

c. Stack gas volumetric flow rate:

$$\text{wscf/hr} = V_s \times A_s \times \frac{530}{T_s} \times \frac{P_s}{407} \times 3600\ \text{sec/hr}$$

$$= \left(33.7\right) \times \left(0.099\right) \times \left(\frac{530}{1089}\right) \times \left(\frac{409}{407}\right) \times \left(3600\right)$$

$$= 5874 \approx 5900$$

$$\text{dscf/hr} = \text{wscf/hr} \times \left(1 - \frac{\%\ H_2O}{100}\right)$$

$$= 5874 \times (1 - 0.173)$$

$$= 4858 \approx 4900$$

where

wscf/hr	= wet std. cubic ft per hr
dscf/hr	= dry std. cubic ft per hr
A_s, stack area ft^2	= πr^2

d. lbs dry flue gas (dfg) per lb of fuel:

For each mole of carbon burned essentially one mole of CO_2 (including minor amounts of CO and hydrocarbons) is formed. From the fuel analysis used there are 112.8 moles of carbon per 100 moles of fuel, and there are also 112.8 moles of carbon species (i.e., CO_2 plus CO plus TOC_3) formed from the 112.8 moles of carbon in the fuel.

Therefore, from the flue gas analysis there are

100 ÷ (10.1 + 2.0 + 0.4) = 8.00 moles dfg per mole of "C" species.

The 100 moles of fuel will yield

112.8 x 8.00 = 902 moles of dfg

Therefore,

$$\left(\frac{902 \text{ moles dfg}}{100 \text{ moles of fuel}}\right) \times \left(\frac{29.8 \text{ lb dfg}}{\text{lb-mole dfg}}\right) \times \left(\frac{\text{lb-mole fuel}}{20.07 \text{ lb fuel}}\right)$$

$$= 13.4 \text{ lb dfg/lb fuel burned}$$

e. Fuel gas flow rate:

$$\text{scf/hr} = \left(\begin{array}{c}\text{stack gas} \\ \text{flow rate,} \\ \text{dscf/hr}\end{array}\right) \times \left(\frac{\text{lb-mole}}{387 \text{ scf}}\right) \times \left(\frac{\text{lb dfg}}{\text{lb-mole dfg}}\right)$$

$$\times \left(\frac{\text{lb fuel}}{\text{lb dfg}} \right) \times \left(\begin{matrix} \text{fuel gas} \\ \text{volumetric density,} \\ \text{19.2 scf/lb} \end{matrix} \right)$$

$$= (4858) \times \left(\frac{1}{387}\right) \times (29.8) \times \left(\frac{1}{13.4}\right) \times (19.2)$$

$$= 536 \approx 540$$

f. Combustion air flow rate (if desired)

$$\text{dscf/hr} = \left(\begin{matrix} \text{fuel gas} \\ \text{flow rate,} \\ \text{scf/hr} \end{matrix} \right) \times \left(\begin{matrix} \text{fuel gas} \\ \text{density,} \\ \text{0.052 lb/scf} \end{matrix} \right) \times \left(\begin{matrix} \text{stoichiometric} \\ \text{A/F ratio,} \\ \text{14.09 lb air/lb fuel} \end{matrix} \right)$$

$$\times \left(\begin{matrix} \text{excess air level} \\ 1.0044 \end{matrix} \right) \times \left(\begin{matrix} \text{volumetric} \\ \text{density of air,} \\ \text{13.34 scf/lb} \end{matrix} \right)$$

$$= (536) \times (0.052) \times (14.09 \times 1.0044 \times 13.34)$$

$$= 5262 \approx 5300$$

g. Engine load, hp-hrs

given, intake manifold vacuum

at idle,	20 in. Hg
during load,	15 - 15-1/2 in. Hg

Using the information on correlating intake vacuum to percentage of full load in Section 3.2.5, determine the actual hp-hrs developed.

Percentage of full load from Figure 3.2-3, ≈28%

hp-hrs developed therefore, are 0.28 x 105 hp, 29 hp-hrs

h. Emission factors:

Formulas used,

$$\text{lb/hr pollutant [A]} = \text{ppm [A], dry} \times \left(\frac{1}{10_6}\right)$$

$$\times \left(\frac{\text{Flue gas flow rate}}{\text{dscf/hr}}\right) \times \left(\frac{\text{lb-mole}}{\text{387 scf}}\right) \times \left(\frac{\text{M.W. [A]}}{\text{lb-mole}}\right)$$

$$\text{g/hp-hr pollutant [A]} = (\text{lb/hr [A]}) \times (454\text{g/lb}) \times \left(\frac{1}{\text{Load} \times \text{hp rating}}\right)$$

lb/10^6 Btu pollutant [A]

$$= (\text{lb/hr [A]}) \times \left(\frac{1}{\underset{\text{scf/hr}}{\text{fuel flow,}} \times \underset{\text{1002 Btu/scf}}{\text{HHV of fuel}}}\right) \times \left(\frac{1 \times 10^6}{1 \times 10^6}\right)$$

Results,

Pollutant	ppm, dry Measured	Emissions lb/hr	g/hp-hr	lb/10^6 Btu
NO_x	200	0.115	1.80	0.22
CO	20,000	7.0	110	13.5
HC as CH_4	1930	0.39	6.1	0.75
as TOC	3900	0.59	9.2	1.14
SO_2*	neg.	0.0003	0.0049	0.0006

*Based on a natural gas fuel sulfur content of 2000 grains/10^6 scf fuel.

3.3 DATA ACQUISITION

Not all surface equipment associated with petroleum production could accurately be characterized by surveying a limited number of production sites. For example one lease might be identical to another in all respects except that the first uses I.C. engines to drive oil well pumps while the second uses electric motors for the same purpose. Total extrapolation of all equipment in one lease to another could therefore lead to errors in emission estimates.

To ensure that the field emission estimates be as accurate as possible, KVB acquired spatial distribution and population data on production equipment such as tanks, boilers, heater treaters, steamers, fire floods, I.C. engines and service equipment such as drilling rigs, workover rigs and welding rigs. Some novel approaches to acquiring this data were attempted. For example, NASA photos taken by U-2 aircraft were purchased to determine if they would be helpful in locating and identifying surface equipment and tank settings. Also, the Spill Prevention Control and Counter Measures Plans submitted to the EPA were investigated as a means to obtain information on storage tanks and tank settings. While these methods were not successful, the use of mail surveys, phone surveys and existing data bases, which could be located, did provide the necessary data to complete the project.

3.3.1 Tanks

It is estimated that there are approximately 10,000 tanks associated with oil production in California. Tanks serve many functions in oil production. The most common are the production tanks which are also known as flow tanks or lease tanks. These are used to receive oil produced from individual leases. Other common tank types found at oil production sites are wash, Lease Automatic Custody Transfer (LACT) and test or gauge tanks.

It became apparent at the beginning of the field survey program that tanks and tank settings were generally associated with leases and not entire fields unless the field was a one-lease field or the field had a unitized or consolidated treatment and storage operation. Leases in each field would have to be identified, but more important the tankage associated with each lease would have to be identified if any emissions estimating accuracy was to be obtained.

As mentioned, previously, aerial photographs and EPA data banks were considered as information sources. Production companies were contacted to determine if they had inventory and size data on their tankage. The ARB's tank data base was explored as an information source. Each of the air pollution control districts serving the eight study counties were contacted to obtain tank information from their data bases.

The most comprehensive and useful information was contained in Ventura County APCD's data base. The most current edition at the time of our analysis was 1978. From it we were able to analyze the tankage in 169 Ventura County oil production leases and develop a lease tankage model based on the leased annual crude production. Details on this model are contained in Section 5.0.

3.3.2 Lease and Well Data

Since it was determined that fugitive emissions could be more accurately analyzed on a lease basis rather than a strict field basis, a source had to be located which would identify each lease in the state and indicate the number of wells in each lease.

The first consideration was to use the Munger or DOG maps, locate each lease, identify its name and count the number of wells. This was quickly discarded since it would be a monumental task and probably not a very accurate method.

The Division of Oil and Gas (DOG) maintained a computerized data base which maintained information on each well in the state. Not only were oil wells included in this system, but also water flood and disposal, steam flood, gas extraction and injection, and pressure maintenance wells. A print-out from the system for an individual well is shown in Figure 3.3-1.

From this computerized data base the DOG was able to generate a field-by-field print-out listing the operator by code number, lease name and the total production of oil and condensate from each lease. Total production by operator, field and county was also listed. Unfortunately, the DOG had not retrieved the number of wells per lease. John Matthews, project consultant who was once in charge of DOG, was able to quantify the number of wells per lease from additional DOG data, Conservation Commission information and personal knowledge. A sample of the printout from the DOG data base is shown in Figure 3.3-2.

3.3.3 I.C. Engines

I.C. engines are ubiquitous in oil production. They are used to drive compressors, power oil wells, and to pump water into injection wells. It has been estimated that approximately 5 percent of the oil wells in California are powered by I.C. engines. Because these engines are so small and numerous, it was difficult to find representative population information. The local APCD's were not able to provide listings. Manufacturers of these engines were not

PROCESSED 07/81

CALIFORNIA DIVISION OF OIL AND GAS
WELL INFORMATION LIST

M 2

PAGE 1109
CMS1014D

DISTRICT: 1 (1) | FIELD CODE: 412 (2) | FIELD: LONG BEACH | AREA CODE: 06 (3) | AREA: OLD AREA

API WELL NO.: 03710904 (4) | LEASE NAME: (5) | OPR WELL NO: 23-5 (6) | SEC 29 T - R 04S 12W BSM SB (7) | WELL STAT: A (8) | OPERATOR CODE: S3100 (9) | OPER STAT: A

OPERATOR NAME AND ADDRESS
SHELL OIL CO
ATTEN SUPERVISOR OF OIL
ACCOUNTING
P O BOX 576
HOUSTON TEXAS 77001

BASIN 0 (10) | REGION 0 (11) | LATITUDE 00 00'00.0" (12) LONGITUDE 000 00'00.0" | GENERAL LOCATION (13)

COUNTY CODE: 19 (14) | COUNTY NAME LOS ANGELES LOS ANGELES | CCS-ZONE 0 (15) X-CORD 0000000E Y-CORD 0000000N | UTM-ZONE 00 (16) X-CORD 0000000E Y-CORD 0000000N | SWRCB NO.: 00000 (17)

POOL CODE:25 (18) | COMPLETION DATE: 04/76 (19) | DEPTH 00000 (20) | X-CORD 00000-0 Y-CORD 00000-0 (21) | REMARKS: (22) 1- 2- 3-

POOL NAME: OTHERS

WELL TYPE	DATE	PROD/INJ STATUS	OIL/COND BBLS	WATER BBLS	PROD DAYS	GAS/PROD MCF	GRAV OIL	CASING PSI	TUBING PSI	BTU	M-O	WATER DISP	WATER/STEAM INJ-BBLS	INJ DAYS	GAS/AIR INJ-MCF	INJ PSI	SOURCE WATER	KIND WATER
06	01/81	00	190	153	31	24	22.6				3	0						
06	02/81	00	202	106	28	28	22.6				3	0						
06	03/81	00	161	92	29	21	22.6				3	0						
06	04/81	00	159	134	30	24	22.6				3	0						
06	05/81	00	97	73	15	11	22.6				3	0						
06	06/81	00	213	16	30	27	22.6				3	0						
06	07/81	00	74	3	12	9	22.6				3	0						
TOTAL			1096	577		144												

Figure 3.3-1

08/15/80 SPECIAL ENGINEERING REQUEST JR KVB ENGINEERING

		COUNTY	FIELD	OPER CODE	LEASE NAME	TOTAL BBLS OF OIL/COND
LSENAME	TOTAL	MONTEREY	MONROE SWELL	C4600	DOUD	11,944
OPRCODE	TOTAL	MONTEREY	MONROE SWELL	C4600		11,944
FIELD	TOTAL	MONTEREY	MONROE SWELL			11,944
LSENAME	TOTAL	MONTEREY	PARIS VALLEY	H6800	ANSBERRY	3,370
OPRCODE	TOTAL	MONTEREY	PARIS VALLEY	H6800		3,370
FIELD	TOTAL	MONTEREY	PARIS VALLEY			3,370
LSENAME	TOTAL	MONTEREY	QUINADO CANYON	B2700	GAMBOA-KELLY	322
OPRCODE	TOTAL	MONTEREY	QUINADO CANYON	B2700		322
FIELD	TOTAL	MONTEREY	QUINADO CANYON			322
LSENAME	TOTAL	MONTEREY	SAN ARDO	M6900	FERRINI	210,323
LSENAME	TOTAL	MONTEREY	SAN ARDO	M6900	HAMBEY	91,007
LSENAME	TOTAL	MONTEREY	SAN ARDO	M6900	ORRADRE	1,634,444
LSENAME	TOTAL	MONTEREY	SAN ARDO	M6900	ORRADRE T	33,200
LSENAME	TOTAL	MONTEREY	SAN ARDO	M6900	ROSENBERG	403,073
OPRCODE	TOTAL	MONTEREY	SAN ARDO	M6900		2,372,135
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	ALEX	4,159
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	ALEXANDER	33,040
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	BARKLEY	23,022
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	DONNA	5,321
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	GROSS	1,000
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	ORRADRE	4,479
LSENAME	TOTAL	MONTEREY	SAN ARDO	T0500	PATRICIA	3,641
OPRCODE	TOTAL	MONTEREY	SAN ARDO	T0500		76,350
LSENAME	TOTAL	MONTEREY	SAN ARDO	T1600	AURIGNAC (NCT-1)	117,493
LSENAME	TOTAL	MONTEREY	SAN ARDO	T1600	DUDLEY	527,316
LSENAME	TOTAL	MONTEREY	SAN ARDO	T1600	GOVERNMENT	12,319

Figure 3.3-2. Sample Print-out from the DOG Data Base

contacted for information since a majority of the I.C.E.'s had been in the oil fields for years and BUDA, a major manufacturer of these engines was no longer in business. The population data used in this program was obtained from a confidential source. It is believed that the data used are the most comprehensive information available.

3.3.4 Boilers, Heater Treaters, Steamers

Heater treaters are used in the oil field and central processing areas to heat the produced fluid, thus destabilizing the oil/water emulsion. Heater treaters are also called line heaters at some facilities. Other heaters found to be similar in design, if not purpose, were gas plant glycol heaters and three phase heaters. Heater treaters are natural draft fire tube units which are fired by either natural gas or oil. Population data for these units were obtained from KVB field surveys, Kern County data provided by the ARB, and a confidential data source.

Oil field boilers and small gas or oil heaters generally provide steam for tank coils, free water knockouts and other miscellaneous uses. Population and spatial information for these units came from KVB's field surveys and survey information provided by the ARB. As with the I.C. engines, these units are generally so small that the local air agencies were not able to provide information on the number or locations of units.

Steamers are relatively large oil- or gas-fired boilers which provide steam for steam flooding or cyclic steam operations. By far the majority of the steamers are used in Kern County's heavy oil fields. Smaller numbers are also found in each of the survey counties. Most of the steamers are fired by produced crude, but steamers in several fields along the coast are fired with natural gas.

To find the extent of steam flooding and cyclic steam injection activities a list of fields with steam injection was prepared from the DOG Annual Report (Ref. 6). Local air agencies for each study county were contacted to provide fuel type and total Btu information on steamers within their jurisdiction. Information was provided by the ARB on units in the San Ardo field and in Kern County. In most cases the Kern County operator was identified but the exact spatial apportionment beyond the Central or Western portion of the county was unknown. Using the list of fields with steamers, Munger maps and the lease and operator data base printout from DOG KVB was able to make a logical distribution of steamers by field for Kern County.

Additional steam generator total heat rate and fuel type information was obtained from Howard Fernbach of Southland Environmental Company (Ref. 8), which is a vendor of oil field steamers and scrubbers. Despite the number of data sources approached, the steam generator heat input rate for several fields was not identified. KVB used judgment based upon the size of the steaming operation and heat rate of comparative operations to assign a heat input rate for modeling purposes.

3.3.5 Fireflooding

In addition to steamflood and cyclic steam injection, fireflooding operations were added to the program under the expanded scope. The size and spatial distribution of fireflood operations were determined from the annual DOG report (Ref. 6). This report also listed the incremental oil quantities produced as a result of fireflooding for several fields. The remaining production was obtained by contacting the District DOG offices. The emission factors that were used for fireflooding were taken from the TEOR Report prepared by KVB for ARB (Ref. 2). These emission factors were based on the barrels of oil produced. This was the only source of combustion generated emissions based on total oil produced. Emissions from steamers, boilers and heater treaters were determined from emission factors based on heat input and I.C. engine emissions were determined from a quantification of daily emissions per engine per day.

3.3.6 Drill Rigs

To estimate the emissions from drilling rigs it was necessary to relate emissions to certain characteristics of the drill rigs and the geology of the various fields. Answers were required to the following questions:

a. How many drill rigs are there in the State?

b. What type of engines are used in the rigs; gasoline, diesel, electric, etc.?

c. How many hours per day are they used in various fields (on the average)?

d. How does the engine load vary with drilling depth?

e. How does the engine load vary with formation composition?

f. What geological formation and pool depth information is available?

Questions were prepared and submitted to 38 drilling contractors listed in the FAUST directory (Ref. 9).

A two-part questionnaire was used as shown in Table 3.3-1. The "A" part was designed to learn general information concerning the regional equipment, usage, and geology. The "B" part of the questionnaire was designed to characterize a typical drilling operation.

Of the 38 questionnaires submitted only eight were completed. However, sufficient information was received so that a credible basis could be developed for emission estimating.

3.4 DATA PROCESSING

A requirement of this project was that a data tape be prepared using the ARB's Area Source Emission System (ASES). However, with the number of oil fields, gas plants and onshore production facilities in the eight study counties and the many processes and pollutants associated with each, the task of preparing the level I, II, and III data sheets would be staggering. Since a computer would be required to generate the data tape from the input data it was decided to prepare a program which would take simplified data concerning each oil field gas plant and onshore production facility, calculate the emissions from each site by process, generate the data tape and prepare a written report listing emissions by field, gas plant or onshore facility, county, air basin, and the entire state. Figure 3.4-1 is a flow chart of the data processing system which was developed for this project.

3.4.1 Concepts

An oil field has certain processes which apply to it as a whole and certain processes which apply to the individual leases of which the field is

TABLE 3.3-1

QUESTIONNAIRE A

General Information

It is understood that oil drilling characteristics can vary from field to field. Therefore, to reflect a general pattern of these characteristics in the various areas of the state, the following counties were grouped together to represent three distinct areas:

Area I (urban)	Area II (coastal)	Area III (rural)
Los Angeles	Monterey	Kern
Orange	San Luis Obispo	Fresno
	Santa Barbara	
	Ventura	

To identify and assess the variable characteristics in each area, the following information is requested.

	Area I	Area II	Area III
Geological formation	________	________	________
Average depth drilled	________	________	________
Average rig size	________	________	________
Type of energy power:			
Diesel	________%	________%	________%
Gasoline	________%	________%	________%
Electric	________%	________%	________%
Average hours of operation	________	________	________
Average hourly consumption rate	________	________	________

Please return to: Nancie R. Parker
KVB, Inc.
18006 Skypark Blvd.
Irvine, CA 92714
(714) 641-6305

(continued)

TABLE 3.3-1 (CONTINUED)

QUESTIONNAIRE B

Typical Well

1. Location of field (county): ________________________________.

2. Type of well: __________ Development well
   __________ Re-drill
   __________ Dry hole
   __________ Wildcat

3. Total depth of hole: __________ feet.

4. Size of rig: __________ 1-2 engines __________ hp
   __________ 2-4 engines __________ hp
   __________ 4-6 engines __________ hp

5. Number of engines used for: __________ drilling
   __________ mud pump

6. Power generation mix: #__________ gas engines
   #__________ diesel engines
   #__________ electric motors

7. Drilling time: __________ hours of operation
   __________ feet per hour

8. Fuel consumption: __________ gallon(s) per hour
   __________ gallon(s) per foot

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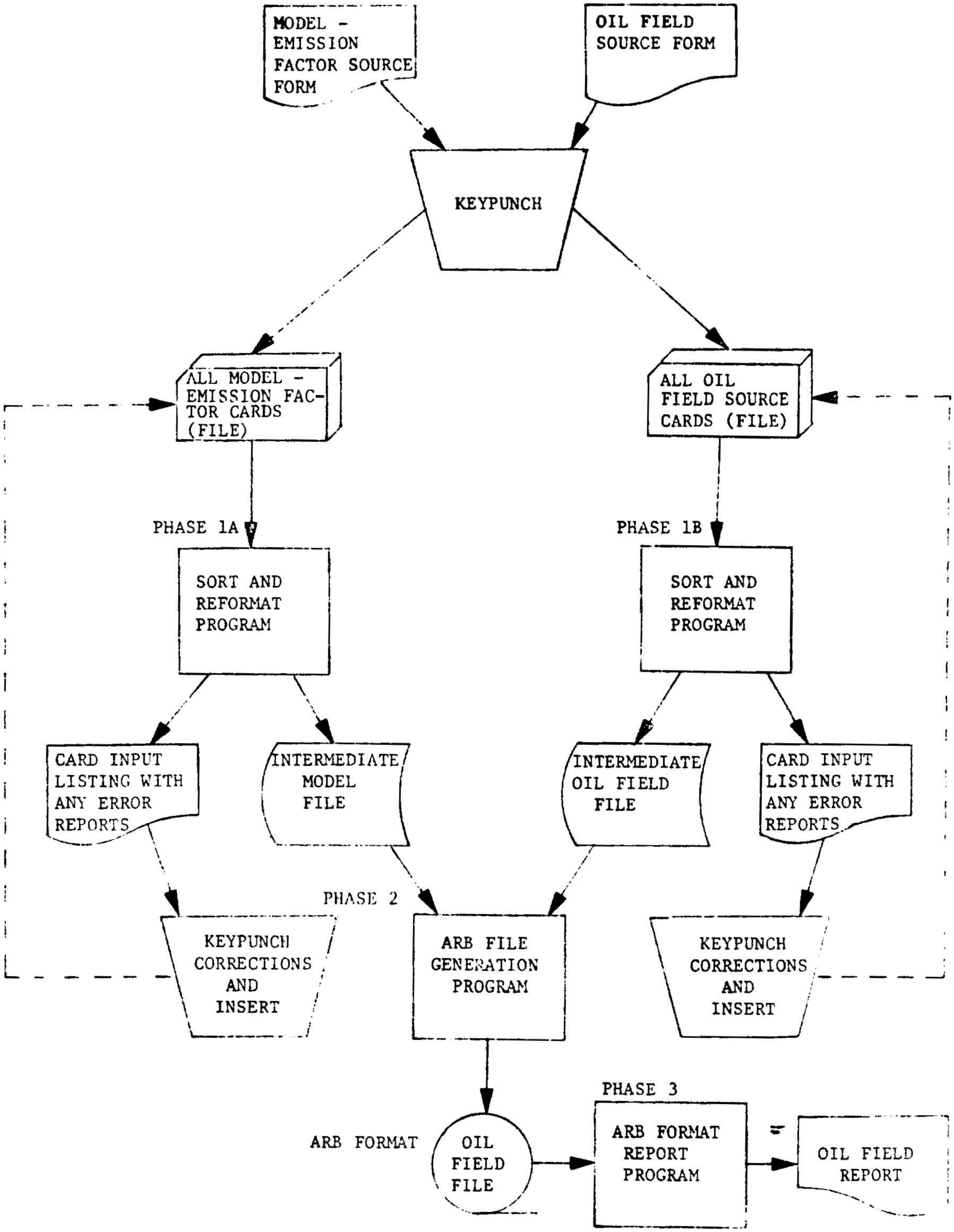

Figure 3.4-1. ARB File Generation Process Flowchart

composed. Lease data is summarized on the input forms without reference to its lease source.

The tape format is modeled upon the ARB's ASES which uses a three-level scheme for reporting emissions. The first level describes the emission source (an oil field), its location, and operating schedule. The second level describes the processes (1-27) which are associated with the emission category. The third level describes from one to five pollutants which may be associated with each process.

There are three categories of models used to transform input data into process and pollutant tape fields. Each category requires its own format and input units. The three model types are oil field processes, lease tankage, and lease models. The first category covers those combustion devices such as heater treaters, steamers, boiler, fire flood, and IC engines which are inventoried on a field basis. Storage and processing tanks are generally associated with a lease rather than a field. Therefore, these models characterize emissions from lease-based tankage. The last category of models determines fugitive emissions from processes such as valves, fittings, pumps, compressors, sumps, etc. on a lease basis.

The following algorithms describe how the emissions are calculated for each model type.

1. Weighted average emission factor for pollutant record E under process record C under Oil Field A

$$= \frac{\sum_{\text{Models}} \text{Units} * \text{Emission Factor}_{\text{pollutant-process}}}{\sum \text{Units}}$$

where Units = Model input unit_a [$*\text{Unit}_b * \text{Unit}_c$]

$*\text{Minor unit factor}_{\text{pollutant-process}}$

2. Yearly process rate for process record C under Oil Field A

$$= \sum_{\text{Models}} \text{Model Input unit}_a \, [*\text{Unit}_b * \text{Unit}_c]$$

$* \text{ Minor unit factor}_{\text{pollutant-process}}$

3. $\text{Emissions}_{\text{pollutant}}$ on report in metric tons/year.

= Yearly process rate * Pollutant Emission Factor

Since there is only one emission factor per pollutant per process per oil field, the factor is calculated by multiplying the number of units by the designated model's pollutant-process-defined emission factor, accumulating all like pollutant-process resultant products for an oil field, and then dividing that number by the number of input units. This produces a weighted average emission factor and the yearly process rate (population).

3.4.2 Implementation and Output

The software was developed to run in a batch mode on an IBM 370 or equivalent, using Job Control Language (JCL) for OS/MVS. Peripherals include a card reader, printer, tape drive and disk drives. The implementation language is IBM VS COBOL. Techniques for software development included structured design and program design language (PDL) as well as structured programming.

Outputs include a nine-track, 1600 bytes per inch EBCDIC tape, containing 208 byte records compatible with the ARB's ASES format. Additionally, an intermediate model file, intermediate oil field file and a final summary report by field, county, air basin, and state are produced.

3.4.3 Inputs

The software uses cards keypunched from Model-Emission Factor Source Forms and from the Oil Field Source Forms which are included in the Appendix.

Lease identification and production information came from the DOG data base. The intention was to enter the information directly into the model by using a data tape provided by DOG. However, it was decided that manual entry of data onto oil field data forms would be preferable for several reasons. First, since counts of equipment such as I.C. engines, heater treaters, etc. would have to be coded on data sheets anyway, it was a minor effort to add the lease model information. Second, DOG experienced difficulty in identifying leases in their data base and providing a printout. They were unable to list the number of wells, per lease from the data base so that information was obtained from other sources.

To run the model in the future, we recommend that the same data entry procedures used during this program be used. The lease information can be updated annually by printing out a paper report in the format shown in Figure 3.3-2. While there was some problem in indicating the number of wells per lease in the DOG printout as shown, that information exists in the data base and is, we believe, retrievable. Since emission factors are also external to the model program and entered separately, they may be modified to reflect candidate control strategies or updated as new emissions data become available.

3.4.4 Data Encoding

The input data were encoded by using and adapting to ARB's ASES. The adaptation was in the creation of new process codes which were not specifically identified by the existing ARB coding procedure for emission producing processes in petroleum production. The process codes (an eight-digit code) describes and identifies each process and is made up of three parts. Part 1 provides a general description of the physical process in which emissions are produced or released. In Part 1, the emission processes from existing codes were categorized as listed:

Physical Process	Code	Emission Producing Process
Combustion of Fuels	P1	IC Engines
		Heater Treater
		Steamer
		Fire Flood
		Boiler
		Flares
Evaporation	P3	Well Cellars
		Sumps & Pits
		Mechanical Oil/Water Separator
Fugitive Losses	P4	Valves
		Fittings
		Well Heads
		Pumps

Fugitive Losses (continued)	Compressors
	Tanks - Working Loss
	Working loss (with vapor recovery)
	Breathing loss
	Breathing loss (with vapor recovery)
	Compressors - drivers

Part 2 identifies the specific application of the process. The existing codes were too general and KVB was unable to facilitate aggregation of emissions by each process. For example valves, fittings, well cellars, well heads, pumps and compressors would all be encoded as:

Process Application	Code
Organic Materials	
Process loss, leakage	561

The results from using this code would have all the above processes and their produced emissions listed as one process (i.e. the first process, valve, as seen by the program). Therefore, after consulting with ARB, each process was given a new code, as shown below:

Process Application	Code
Petroleum Production	
Valves	950
Fittings	951
Well Cellars	952
Well Heads	953
Pumps	954
Compressors	955
Sumps and Pits	956
Mechanical Oil/Water Separator	957
IC Engines	958
Heater Treater	959

Steamer/Boiler - Oil	960
Fire Flood	961
Steamer/Boiler - Gas	962
Tanks	
Working Loss	963
Working Loss (with vapor recovery)	964
Breathing Loss	965
Breathing Loss (with vapor recovery)	966
Compressors/Drivers	967
Flares	968

Part 3, the last three-digit portion of the code, indicates the fuel, product consumed or operated by the described process. Also associated with Part 3 are units of throughput which correspond to an emission factor for each process. Again, the existing codes were too general and/or non-existent and new codes were created:

Process	Throughput Limits	Code
Valves	Number of Wells	113
Fittings	Number of Wells	113
Well Cellars	Number of Wells	113
Well Heads	Number of Wells	113
Pumps	Number of Wells	113
Compressors	Number of Wells	113
Sumps and Pits	Number of Wells	113
(Wenco)	Number of Wells	113
IC Engines	Number of Engines	114
Heater Treater	MBtu/hr	115
Steamer/Boiler - Oil	MBtu/hr	115
Fire Flood	10^3 bbl/yr	116
Steamer/Boiler - Gas	MBtu/hr	115

Tanks		
Working loss	10^3 bbl/yr	116
Working loss (with vapor recovery)	10^3 bbl/yr	116
Breathing loss	10^3 bbl/yr	116
Breathing loss (with vapor recovery)	10^3 bbl/yr	116
Compressors/Drivers	10^6 cf/day	117
Flares	10^6 cf/day	117

From the preceding coding definitions, Table 3.4-1 summarizes the three-part process code per process for petroleum production.

3.5 EMISSION FACTOR BASIS

3.5.1 Oil Production Fugitive Hydrocarbon Emissions

Valve and fitting emission factors used to determine emissions for this project were statistically developed from two sources. The first was the fugitive's hydrocarbon emissions study performed by Rockwell International for API (Ref. 1). The second was the site survey and model categorization conducted by KVB on this program.

As explained in more detail in Section 6.0, the Rockwell report expressed fugitive emissions as lb/day from individual leak points such as flanges, threaded connections, or valve bonnets (repacking nut). To obtain an emission factor for an individual component such as a gate valve, threaded coupling or welded T, a building block approach had to be used where the emissions from each leak point were added together.

These valve and fitting emission factors were applied to the detailed production site inventory conducted by KVB and summed to obtain total daily hydrocarbon emissions from valves and fittings for each site. Summing the daily emissions for all leases within a lease model category and dividing by the total number of wells yields emission factors in pounds per day per well for valves and fittings for that lease model category.

TABLE 3.4-1. PETROLEUM PRODUCTION PROCESS CODES IN DATA BASE

Process	Process Codes
Valves	P4-950-113
Fittings	P4-951-113
Well Cellars	P3-952-113
Well Heads	P4-953-113
Pumps	P4-954-113
Compressors	P4-955-113
Sumps and Pits	P3-956-113
Mechanical Oil/Water Separator	P3-957-113
IC Engines	P1-958-114
Heater Treater	P1-959-115
Steamer/Boiler - Oil	P1-960-115
Fire Flood	P1-961-116
Steamer/Boiler - Gas	P1-962-115
Tanks	
Working loss	P4-963-116
Working loss (with vapor recovery)	P4-964-116
Breathing loss	P4-965-116
Breathing loss (with vapor recovery)	P4-966-116
Compressor/Drivers	P4-967-117
Flares	P1-968-117

Valve and fitting population data were not carried beyond lease summary sheets and entered into the computer program. Hence, population estimates, while not tabulated were implicit in the final emissions results.

Emissions from devices such as compressors were developed using the building block approach described in Section 6.0. These, too, were expressed in terms of pounds per day per well for each lease category.

Miscellaneous sources such as sumps, pits or well cellars were inventoried on an area basis. This was compatible with the Rockwell format. As with the other sources, emissions were summed and divided by the number of wells.

3.5.2 Tanks

One of the more difficult tasks was to develop a model for estimating lease tankage and the associated emissions. From the emission equations in EPA's AP-42 (Ref. 4) as modified by the Western Oil and Gas Association Report (Ref. 10), it was determined that molecular weight, vapor pressure, tank size and aspect ratio, diurnal temperature change, paint condition and color and tank capacity all impact the emissions. These equations are complex and require extensive information concerning the tankage and conditions at each lease tank setting. Hence, it was necessary to develop a method to obtain and assess these data on a collective basis. Since data and methodologies required to perform specific estimates of emissions are not available at this time, short cuts were used to estimate emissions from tanks and sumps.

The approach used to make the emission factors usable and amenable to the computer modeling technique was to perform a statistical analysis of lease tankage. Tank capacity was determined as a function of production rate. An assessment was also made of the impact on emissions of the parameters in the AP-42 equations. By plotting annual lease oil production versus lease tankage, a production-tankage correlation was developed. The analysis of the tank emission factor equations showed that breathing losses could be reduced to a function of total lease tankage and working loss to a function of annual lease throughput. If the tankage is known or suspected to have vapor recovery, a 90 percent reduction factor was applied to these equations to account for the reduced emissions.

3.5.3 Gas Plants

The approach used to develop fugitive hydrocarbon emission factors for gas plants was similar to that for crude oil production facilities. Emission factors were developed from applying valve fitting, and equipment population counts to component emission factors derived from the API report prepared by Rockwell (Ref. 1). These then were corrected to pounds per day per component type such as valves or fittings expressed on the basis of million cubic feet per day throughput (i.e., valve emissions = lb/day - MCFD).

Emission factors for other sources such as compressor drivers or heaters were obtained from appropriate sources such as AP-42 (Ref. 4) or developed from material balances. These, too, were expressed in a per million cubic feet per day basis.

Since emission factors were developed on a throughput basis, the total emissions from an unknown gas plant can be approximated by multiplying the project emission factors by that plant's daily gas throughput.

3.5.4 Combustion Equipment

Emission factors for combustion equipment came from several sources. These included:

a. Small IC Engines - KVB field tests

b. Large IC Engines - AP-42 (Ref. 4)

c. Heater Treaters - KVB field tests

d. Gas-Fired Steam Generators and Boilers - AP-42 (Ref. 4)

e. Oil-Fired Steam Generators and Boilers - KVB's Tertiary Oil Report to CARB (Ref. 2)

f. Fire-Flooding - KVB's Tertiary Oil Report to CARB (Ref. 2)

g. Diesel Engines - AP-42 (Ref. 4)

The format of the emission factors used in this program depended upon the device and form of the survey information. For instance, the IC engine emission factor was expressed per engine; the fireflood emission factor was expressed per unit of oil produced and the heaters, boilers, and steamers had emission factors expressed in terms of million Btu per hour input.

SECTION 4.0

FIELD TEST RESULTS

A number of observations and measurements were made to determine the average NO_x, CO, SO_2, and THC emissions from IC engines, heaters and heater treaters in oil field service. Presented within this section are the results of these efforts.

A total of 22 IC engines and 8 heaters and heater treaters were tested at three oil-field locations using the test methods and calculations outlined in Section 3.0. The general lack of any type of combustion or process monitoring equipment (such as fuel flow rate) on the IC engines and most of the heaters or heater treaters tested required that the performance of these units be calculated based on exhaust gas flow and composition measurements. All of the equipment tested except one burned processed field gas or city supplied natural gas fuel. The one exception was a vertical heater which burned LPG fuel. No oil-fired equipment were tested. Tests were conducted at four separate oil fields located in the South Coast Air Basin (SCAB).

4.1 INTERNAL COMBUSTION ENGINES

Of the 22 IC engines in oil field service tested, fourteen of these engines have horsepower ratings less than 100. Eight have horsepower ratings between 100 and 300. Sixteen of the engines tested are used to drive sucker-rod-type, oil-well pumps. Six are used to supply power to a parallel connected hydraulic lift oil production system.

Summarized in Table 4.1-1 are the individual test results for all 22 engines. Indicated are each engine's make, model, horsepower rating, and key operating parameters such as fuel flow, manifold vacuum, A/F ratio, and ambient temperature and barometric pressure. Also shown are the measured composition of the stack gas and the Bacharach smoke spot number (SSN). Note that the emissions data are presented as measured at the excess O_2 value indicated and on a standardized basis of 15 percent excess O_2.

TABLE 4.1-1. INTERNAL COMBUSTION ENGINE TESTS RESULTS
Primary Oil Production Research Program

Unit No.	1	2	3	4	5	6	7
Make	Waukesha	Buda	Buda	Waukesha	Waukesha	Waukesha	Waukesha
Model	817	K428	L525	817	817	554	817
HP Rating	105	50	62	105	105	83	105
Fuel Type	Processed Field Gas						
Load, %	40	45	43	29	35	18	18
Fuel Flow, scf/hr, calc.	600	250	200	540	470	290	350
Manifold Vacuum, in. Hg., Load/Idle	12/16	13/16	11/12	15/20	13/16	14/16	15/17
A/F Ratio, by volume	9.6	15.1	13.6	10.2	11.2	11.1	10.3
Stack Gas Composition, dry basis							
• CO_2, %	6.3	9.4	8.3	10.1	8.1	9.2	11.4
• O_2, %	1.9	0.45	2.7	1.1	4.0	0.95	1.4
• CO/@ 15% O_2, ppm	64,000/20,000	28,000/8130	27,000/8800	20,000/6000	24,000/8400	20,000/6000	2500/761
• NO_x/@ 15% O_2, ppm	40/12.4	126/36	175/57	200/60	475/167	298/89	2065/628
• HC, CH_4/@ 15% O_2, ppm	--/--	--/--	--/--	1930/580	9500/3300	2900/863	2000/609
, TOC/@ 15% O_2, ppm	--/--	--/--	--/--	3900/1170	12,900/4500	5300/1600	3600/1100
• SO_2, ppm calc./@ 15% O_2	0.38/0.12	0.25/0.073	0.28/0.091	0.37/0.11	0.34/0.12	0.34/0.10	0.36/0.11
Stack Gas Temp., °F	573	488	381	629	559	496	525
Stack Gas Moisture Content, %	16.6	17.8	16.0	17.3	15.1	17.4	17.0
Bacharach SSN (0-9)	1-2	0-1	2-3	2-4	2-3	0-1	1-2
Flue Gas Flow, dscfh	5400	3400	2500	4900	4800	2900	3300
Ambient Air Temp., °F	72	66	66	66	62	62	66
Ambient Air Wet Bulb Temp., °F	58	55	55	55	48	48	50
Relative Humidity, %	44	50	50	50	32	32	32
Barometric Pressure in. Hg.	30.10	30.09	30.09	30.08	30.34	30.31	30.30
Well Gross Prod., bbl/day	240	10	81	673	688	78	182

(continued)

Revised 1-12-82

TABLE 4.1-1. (CONTINUED)

Unit No.	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Make	Buda	Buda	Buda	Buda	Buda	Waukesha	Buda	Buda	Climax	MM	MM	MM	MM	Waukesha	Waukesha
Model	L525	L525	L525	K428	HP326	140GUB	K428	L525	--	800	800	800	800	6WAK	6WAK
HP Rating	85	85	85	75	65	140	75	85	300	65	65	65	65	133	133
Fuel Type	<—— Long Beach City Gas ——>									<—— Lomita City Gas ——>					
Load, %	23	22	36*	33	37	30	28	12	--	60	37	42	55	55	65
Fuel Flow, scf/hr, calc.	430	440	370*	450	390	750	360	300	900	500	800	500	550	1080	1180
Manifold Vacuum, In. Hg., Load/Idle	15/18	13.5/15	12/16.5	13/17.5	12.5/18	14.5/19	14/18	17/18.5	20/--	8/17.5	13/16	12/19	10.5/22	10.5/19	5.5/16
A/F Ratio, by volume	18.4	14.7	20.3	15.1	16.6	11.	--	17.5	13.2	12.3	11.9	11.2	11.6	10.1	10.9
Stack Gas Composition, dry basis															
. CO_2, %	6.8	8.5	6.1	8.1	7.6	7.4	7.2	6.3	9.6	10.3	10.9	8.8	10.7	8.6	8.6
. O_2, %	8.4	6.0	9.5	6.6	7.7	5.6	7.8	7.6	4.1	3.0	0.35	1.90	0.44	0.40	2.0
. CO/@ 15% O_2, ppm	330/156	1000/398	285/148	2000/829	3000/885	36,000/14,000	2500/1130	9000/4010	385/136	2100/700	4000/1160	25,000/7800	11,000/3200	41,000/1200	30,000/9420
. NO_x/@ 15% O_2, ppm	820/389	834/332	207/108	411/170	396/117	197/76	534/242	130/58	384/136	1124/373	304/88	293/92	1235/358	153/44	109/34
. HC, CH_4/@ 15% O_2, ppm	6.3/3.0	26/10.7	49/25	--/--	--/--	1.6/0.62	--/--	--/--	11/3.9	166/55	--/--	5500/1720	--/--	194/56	203/64
, TOC/@ 15% O_2, ppm	460/218	4140/1650	4300/2200	--/--	--/--	1840/713	--/--	--/--	1170/413	830/275	--/--	7000/2200	--/--	1940/560	1180/370
. SO_2, ppm calc./@ 15% O_2	0.19/0.090	0.28/0.11	0.18/0.094	0.24/0.10	0.23/0.10	0.33/0.13	--	0.21/0.094	0.28/0.099	0.30/0.099	0.32/0.092	0.34/0.11	0.34/0.099	0.37/0.11	0.34/0.11
Stack Gas Temp., °F	667	758	776	742	507	650	620	--	375	741	791	612	800	725	--
Stack Gas Moisture Content, %	10.8	13.1	9.8	12.3	12.2	13.2	11.3	11.4	14.5	15.6	17.9	16.5	17.8	17.7	16.3
Bacharach SSN (0-9)	--	7-8	2	3-4	1	0-1	1-2	4	1	1-3	2-3	1-2	4	2	--
Flue Gas Flow, dscfh	7750	5400	6970*	6400	5800	7880	--	4870	10,900	5700	8600	5100	5500	10,000	11,800
Ambient Air Temp., °F	66	68	65	72	75	76	76	65	76	62	62	70	70	73	79
Ambient Air Wet Bulb Temp., °F	61	60	59	62	64	60	60	59	60	55	55	61	61	61	62
Relative Humidity, %	76	70	71	58	56	40	40	71	40	64	64	60	60	51	40
Barometric Pressure In. Hg.	29.93	29.91	29.89	30.10	30.07	30.00	29.98	29.89	30.00	30.07	30.06	30.05	30.04	29.97	30.03
Well Gross Prod., bbl/day	25	32	14	17	83	29	74	26	1700	N.A. - Hooked up to Kobe System					

* Engine pulsating badly
-- Indicates either data was not available or samples were not taken
N.A. Not applicable
MM Minneapolis-Moline

Revised 1-12-82

Summarized later in Table 4.1-2 are the average emission factors computed for the 2 engine horsepower groups tested, <100 HP and >100 HP, along with a weighted composite of the total.

4.1.1 Field Tests Results

The operating condition of each engine tested varied considerably due to differences in age, load, and maintenance as discussed in Section 3.0. Looking at the test data presented in Table 4.1-1, the load at which each engine operated varied from 12 to 65 percent of rated horsepower with an average load of 37 percent measured. Similarly, the volumetric air-to-fuel ratio (A/F) measured on each engine varied from a low of 9.6:1 to a high of 20.3:1 with an average of 13.1:1. The stoichiometric A/F ratio (volumetric) is approximately 9.7:1. (On a mass basis the stoichiometric A/F ratio would be approximately 14.2:1.) Consequently, some engines operated near the stoichiometric ratio while others operated in a lean regime.

Looking at the composition of the stack gas measured, the concentration of CO corrected to 15 percent O_2 varied from a low of 140 ppm to a high of 20,000 ppm. Similarly, the concentrations of NO_x corrected to 15 percent O_2 varied from 12 ppm to 630 ppm, a 50 fold difference. Concentrations of total hydrocarbons reported as CH_4 and TOC corrected to 15 percent O_2 ranged from 0.62 ppm to 3300 ppm, and 220 to 4500 ppm, respectively. Also measured were the Bacharach SSN's which varied from 1 to 8. The concentrations for SO_2 listed in Table 4.1-1 were calculated based on an assumed natural gas sulfur content of 2000 grains/10^6 SCF as reported in AP-42, Section 1.4.1. The extremely low levels of SO_2 produced from such small quantities of sulfur were below the detection limit of the instrument used and therefore were calculated. The SO_2 instrument was used on all tests to detect any deviations from this assumption. None were found.

In summary, the test results showed that the wide variation in engine operating conditions typically found in oil fields produce similar variations in engine performance and levels of CO, NO_x, THC, and carbon emitted. The findings also suggest that there is no single correlation between the concentration of NO_x emitted and the A/F ratio when all the other possible interacting variables are considered (i.e., engine load, date of last tune-up, compression, timing, etc.). Consequently, no correlation between the levels

TABLE 4.1-2. EMISSION FACTORS FOR GAS-FIRED INTERNAL COMBUSTION ENGINES FOUND IN CALIFORNIA OIL FIELDS*

	Nitrogen Oxides (as NO_2)		Carbon Monoxide		Hydrocarbons CH_4		Hydrocarbons TOC		Sulfur Dioxide†
	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	Estimated
Internal Combustion Engines									
≤ 100 HP									
ppm, dry @ 15% O_2	180	36-389	3100	148-8800	450	3.0-1720	1400	218-2200	0.096
lb/hr§	0.35	0.051-0.81	3.3	0.19-9.3	0.32	0.0020-1.2	0.51	0.11-1.1	0.00024
grams/HP-hr	6.6	0.88-18	74	4.2-230	7.9	0.047-28	13	1.7-27	0.0051
lbs/MMBtu	0.71	0.20-1.6	9.2	0.41-27	0.70	0.0042-2.2	1.1	0.23-2.1	0.00053
lbs/M bbl. gross production	240	16-730	3100	180-17,000	39	1.9-110	260	110-520	0.18
ng/J	310	86-690	4000	180-11,600	300	1.8-930	470	100-1000	0.23
100-300 HP									
ppm, dry @ 15% O_2	140	12-628	8800	136-20,000	660	0.62-3300	1300	413-4500	0.11
lb/hr§	0.28	0.026-0.81	15	0.31-30	0.39	0.00052-1.9	0.67	0.37-1.9	0.00040
grams/HP-hr	4.0	0.28-19	150	14-270	6.1	0.0057-23	8.8	2.3-24	0.0040
lbs/MMBtu	0.51	0.042-2.2	18	0.32-40	0.79	0.00064-3.9	1.1	0.34-4.0	0.00054
lbs/M bbl. gross production	57	2.6-160	4000	79-17,000	29	0.43-66	130	20-370	0.088
ng/J	220	18-950	7700	140-17,200	340	0.28-1700	470	150-1700	0.23
Weighted Composite ≤100 HP 100-300 HP									
ppm, dry @ 15% O_2	170	12-628	5200	136-20,000	560	0.62-3300	1300	218-4500	0.10
lb/hr§	0.32	0.026-0.81	8.0	0.19-30	0.36	0.00052-1.9	0.60	0.11-1.9	0.00030
grams/HP-hr	5.6	0.28-19	102	4.2-270	6.9	0.0057-28	11	1.7-27	0.0047
lbs/MM Btu	0.64	0.042-2.2	13	0.32-40	0.75	0.00064-3.9	1.1	0.23-4.0	0.0053
lbs/M bbl. gross production	170	2.6-730	3400	79-17,000	33	0.43-110	190	20-520	0.14
ng/J	270	18-950	5500	140-17,200	320	0.28-1700	470	100-1700	0.23

*Results based on tests run on 22 gas-fired internal combustion engines; eight have HP ratings >100 HP, and 14 have HP ratings ≤100 HP. Average engine load measured was 37%, HP 88. Tests occurred at three different oil fields in the South Coast Air Basin. Fuel used was either natural gas or processed field gas.

†Based on a typical natural gas sulfur content of 2000 grains per 10^6 scf as reported in AP-42, Section 1.4.1.

§Even though lbs/hr is an emission rate and not an emission factor, it is provided here for convenience.

of CO, NO_x, or THC emitted and a specific operating parameter were developed from the test data. However, a set of overall emission factors was developed and are presented in the Section 4.1.2. The summary below lists the average engine operating conditions found and concentrations of gaseous species measured.

• Avg. Load,	37%	• Avg. CO @ 15% O_2	5200 ppm*
• Avg. HP,	88	• Avg. NO_x @ 15% O_2	170 ppm*
• Avg. A/F ratio,	13.1:1	• Avg. HC @ 15% O_2	
• Avg. SSN,	0-3	-CH_4	560 ppm*
		-TOC	1300 ppm*

4.1.2 Emission Factors

Summarized in Table 4.1-2 is a list of emission factors for gas-fired, oil-field-service, IC engines. The derivation of these emission factors was based on the test results obtained from the 22 engines tested. Shown are the arithmetic average and range of emission for NO_x, CO THC as CH_4 and TOC and SO_2 for the two engine horsepower groups tested along with a weighted composite for both groups.

Emissions are reported in units of ppm dry @ 15 percent O_2, lb/hr, grams/Hp-hr, lb/MMBtu, lb/Mbbl gross production, and ng/J.

The wide range in emission levels for each pollutant is due to the wide variation in engine operating conditions found as previously discussed.

4.2 HEATERS AND HEATER TREATERS

A descriptive breakdown of these eight oil-field-service heaters and heater treater devices is as follows:

1. & 2. Trico Superior, 500,000 Btu/hr heaters (single burner)

3. C-E NATCO, 348,000 Btu/hr Glycol Reboiler (single burner)

*Reported on a dry basis

4. Trico Superior 8,000,000 Btu/HR heater-treater (double burner)

5. C-E NATCO 348,000 Btu/HR vertical heater (single burner, LPG fuel)

6. C-E NATCO 10,000,000 Btu/HR heater-treater (double burner)

7. & 8. Trico Superior 6,000,000 Btu/HR heater-treater (double burner)

Of the eight units tested, four used a single burner/firetube arrangement and four used a dual burner/firetube arrangement for heating the process fluid as noted. Each heater also had a separate gas pilot light which burned continuously and provided a source of ignition for the main burner. All of the units tested except the LPG-fired vertical heater burned either processed field gas or natural gas.

All of the heaters tested normally operate on a intermittent basis. From an emissions-monitoring standpoint, this meant that process and emissions data had to be collected using one of two approaches. The first approach essentially involved collecting data when a unit was "on" and not collecting data when the unit was "off". The second approach involved the temporary installation of a pneumatic auto/hand relay station to regulate the flow of gas (firing rate) to a burner.

Both approaches were used. With the first approach, KVB collected data when the unit was "on." No variations in firing rate were possible. With the second approach, KVB controlled the on-off cycle and flow of gas fuel. Using the second approach tests were conducted under different firing rates. The first approach was used on the five units tested at the first test site. The second approach was used on the three units tested at the remaining two tests sites.

Using the two test approaches a total of 22 tests were conducted at various firing rates on the eight heaters. The results of these tests are summarized in Table 4.2-1. Indicated are the unit make, Btu/HR heat input rating, percent of rated Btu input, and the composition of the stack gas along with other key operating parameters. Also presented along the bottom of each

TABLE 4.2-1. HEATER AND HEATER-TREATER TESTS RESULTS
PRIMARY OIL PRODUCTION RESEARCH PROGRAM

Unit No.					1					2		3	
Make					C-E Natco Heater-Treater					Trico Superior Heater-Treater			
Rating, Btu/hr Input					(5 MM/Burner) x 2					3 MM/Burner) x 2			
N.G. flow-scf/hr·burner					7400					4400			
Avg. Daily Fuel Consumption, mcf/day					97					33			
Fuel Type					Processed Field Gas					Processed Field Gas			
Burner Location	Right				Left				South		North		
Fuel Flow, scf/hr	11-14*	6000†	5600†	5400†	5400†	5100†	4400†	11-14*	1050§	1530§	2100§	1630§	2700§
% of Rated Btu Input	Pilot Light	80	75	73	73	70	60	Pilot Light	24	35	48	37	61
A/F Ratio, by volume	—	11.3	10.1	11.9	14.8	15.9	19.5	—	23.4	15.5	14.2	18.2	11.3
Stack Gas Composition, dry basis													
• CO_2, %	0.75	11.1	11.9	10.3	8.1	7.2	5.5	0.8	5.2	7.9	8.8	6.8	10.9
• O_2, %	19.6	0.32	0.95	3.7	6.7	8.0	10.7	19.5	11.7	7.4	5.9	8.8	2.0
• CO/@ 3% O_2, ppm	6000/80,000	10,000/8700	4000/3600	120/125	665/840	4000/5500	2000/3500	10/120	45/89	41/54	45/54	32/47	4000/3800
• NO_x/@ 3% O_2, ppm	5.6/75	24/21	26/23	24/25	33/41	24/34	17.3/31	8.7/107	33/64	44/59	65/77	32/48	58/55
• HC, CH_4/@ 3% O_2, ppm	2900/39,000	N.T./—	34/31	N.T./—	<1/—	1470/2100	2100/3700	101/1250	4.5/8.9	1.6/2.1	<1/—	3.6/5.3	1.4/1.3
• HC, TOC/@ 3% O_2, ppm	5700/76,000	N.T./—	117/105	N.T./—	11.0/13.9	2200/3100	3600/6300	99/1226	7.3/14.5	5.4/7.1	78/93	4.5/6.6	1.8/1.7
• SO_2, ppm calc./@ 3% O_2	—	0.34/0.29	0.38/0.34	0.32/0.33	0.25/0.32	0.24/0.33	0.19/0.33	—	0.15/0.30	0.23/0.31	0.26/0.31	0.20/0.30	0.33/0.32
Bacharach Smoke Spot No. (0-9)	0	10	6-8	3-4	3-4	5-6	5-6	0	0	0	0	0-1	1
Stack Gas Temp., °F	~172	816	908	841	689	595	494	N.T.	486	591	578	539	608
Stack Gas Moisture Content, %	1.2	17.9	17.4	15.1	12.4	11.3	8.9	1.3	8.1	10.0	13.1	10.5	16.4
Approx. HHV Fuel, Btu/scf @ 70°F and 14.7 psia	1000 ——>								1070 ——>				
Emission Factors:													
• lbs/10^6 Btu - CO	26	7.3	2.5	0.096	0.67	4.3	2.7	0.104	0.073	0.044	0.043	0.040	3.0
- NO_x as NO_2	0.040	0.029	0.027	0.031	0.054	0.042	0.038	0.152	0.088	0.077	0.104	0.066	0.071
- HC, CH_4	7.2	—	0.0122	—	neg.	0.90	1.63	0.60	0.0042	0.001	neg.	0.0026	0.00080
- , TOC	10.6	—	0.031	—	0.0047	1.01	2.1	0.44	0.0051	0.0025	0.032	0.0024	0.00057
- SO_2#	0.0006 ——>								0.0006 ——>				
Average Daily Emission Rates:‡	Pilot Only**					Unit Firing							
• lbs/unit·day - CO	4.6					280				21			
- NO_x as NO_2	0.035					3.6				2.7			
- HC, CH_4	1.40					61				0.069			
- , TOC	1.98					230				0.28			
- SO_2	neg.					0.058				0.0198			

(continued)

* Manufacturer's reported data
† Based on plant orifice meter
§ Based on KVB stack gas velocity measurement in conjunction with combustion calculations
\# Based on a typical natural gas sulfur content of 2,000 grains/10^6 scf as reported in AP42, Section 1.4.1
‡ Based on the reported average daily fuel consumption in conjunction with the computed average pollutant emission factor. Pilot light test are not included.
** Daily emission rate based on unit being off ~60% of the time
N.T. Sample not taken
$\bar{x}$ Arithmetic mean
S Standard deviation

Revised 1-12-82

TABLE 4.2-1. (CONTINUED)

Unit No.	4	5	6			7			8
Make	Trico Superior Heater		C-E Natco			Trico Superior Heater-Treater			C-E Natco
Rating, BTU/hr output	500M	500M	348M			(4MM/burner) x 2			348M*
, N.G. flow-scf/hr burner	770	770	535			5900			200
Avg. Daily Fuel Consump., mcf/day	N.A.	N.A.	8			78			2
Fuel Type	Field Gas					Field Gas			LPG
Burner Location	Single Burner					West	East		
Fuel Flow, scf/hr	620*	620*	220†	420†	380†	3,200§	1,460†	4,700†	95§
% of Rated Btu Input	80	80	41	78	71	54	25	80	47
A/F Ratio, by volume	10.1	9.2	28.3	11.8	17.4	15.6	30.0	12.7	--
Stack Gas Composition, dry basis									
. CO_2, %	12.2	8.5	4.5	10.2	8.5	8.2	3.9	5.2	1.3
. O_2, %	1.2	0.84	14.2	4.2	7.0	7.3	14.0	9.6	18.5
. CO/@ 3% O_2, ppm	2000/1820	42,000/60,000	60/159	75/80	60/77	500/660	1500/3900	130/148	40/290
. NO_x/@ 3% O_2, ppm	37/34	20/18	29/77	55/59	46/59	26/34	11.2/29	49/56	6.5/48
. HC, CH_4/@ 3% O_2, ppm	118/107	50/71	N.T./--	0.5/0.5	N.T./--	N.T./--	N.T./--	N.T./--	8.4/61
. HC, TOC/@ 3% O_2, ppm	145/132	70/100	N.T./--	4.4/4.7	N.T./--	N.T./--	N.T./--	N.T./--	154/1130
. SO_2, ppm calc.‡/@ 3% O_2	0.37/0.34	0.41/0.36	0.13/0.34	0.32/0.34	0.22/0.28	0.25/0.34	0.12/0.31	0.29/0.45	--
Bacharach Smoke Spot Number (0-9)	1-2	5-7	0-1	0-1	0-1	0-1	0-1	0-1	N.T.
Stack Gas Temp., °F	574	539	677	1024	N.T.	685	371	790	740
Stack Gas Moisture Content, %	17.2	17.5	5.8	14.6	12.2	16.7	6.0	13.8	2.7
HHV Fuel, Btu/scf @ 70°F and 14.7 psi	993---------->								2500
Emission Factors:									
. lbs/10^6 Btu - CO	1.30	26	0.119	0.065	0.058	0.50	3.2	0.112	0.28
- NO_x as NO_2	0.041	0.020	0.096	0.072	0.072	0.043	0.039	0.070	0.074
- HC, CH_4	0.045	0.0175	--	neg.	--	--	--	--	0.033
- TOC	0.042	0.0185	--	0.00151	--	--	--	--	0.46
- SO_2	0.0006	0.0006	0.0006---------->			0.0006---------->			0.0006
Avg. Daily Emission Rates:#									
. lbs/day/unit - CO			6.4			99			1.41
- NO_x as NO_2	N.A.	N.A.	0.63			3.9			0.37
- HC, CH_4			neg			--			0.167
- HC, TOC			neg			--			2.3
- SO_2			0.0048			0.047			--

* Estimate based on field observations
† Based on plant orifice meter
§ Based on KVB stack gas velocity measurements in conjunction with combustion calculations
‡ Based on a typical natural gas sulfur content of 2000 grains/10^6 scf as reported in AP42, Section 1.4.1.
\# Based on the reported average daily fuel consumption in conjunction with the computed average pollutant emission factors.
N.T. Sample not taken
N.A. Data not available
$\bar{X}$ Arithmetic average
S Standard deviation

Revised 1-12-82

table are emission factors in units of $lb/10^6$ Btu fired for each firing rate tested and average daily emission rates in units of lb/day for each unit. The average daily emission rates were computed using the associated emission factors in conjunction with average daily fuel consumption rates. These were supplied when available by the owner of the unit.

Table 4.2-2 summarizes the average emission factors computed for the three groups of heaters tested; 3 - 5 MMBtu/HR, dual-burner heater-treaters 500,000 Btu/HR indirect fired heaters, and 500,000 Btu/HR direct, LPG-fired vertical heaters -- along with emission factors for the pilot light only tests. The pilot light only tests were considered an important operating condition to document because these types of units normally operate for a great deal of time with only the pilot light burning.

4.2.1 Field Tests Results

A significant amount of variation in operating conditions and emission levels was found among the eight heaters and heater-treaters tested. A number of tests conducted on different units at different firing rates indicated that variations in load, may or may not have an effect on the levels of CO, NO_x, THC's and carbon emitted and it is not possible to predict what that effect may be (i.e., increase or decrease). Five of the units tested were found operating with extremely high A/F ratios as indicated by the high levels of excess O_2 measured in the flue gases. In comparison, three other units were found operating with A/F ratios near the stoichiometric ratio as indicated by the very low excess O_2 levels measured. On these units, partially plugged and/or corroded air intake flame arrestors were found to be the cause of the low excess air levels.

During normal operation, the concentrations of CO corrected to 3 percent O_2 measured in the flue gases ranged from a low of 47 ppm to a high of 60,000 ppm. Similarly, the concentrations of NO_x corrected to 3 percent O_2 varied from 21 ppm to 77 ppm the concentrations of THC's as CH_4 and TOC corrected to 3 percent O_2 varied from roughly 0 to 3900 ppm and 2 ppm to 6300 ppm, respectively. Lastly, the Bacharch SSN ranged from a low value of 0 to a high value of 9. Considerably higher emission levels were measured during the pilot light only tests as indicated.

TABLE 4.2-2. EMISSION FACTORS FOR GAS-FIRED OIL-FIELD-TYPE HEATERS AND HEATER-TREATERS FOUND IN CALIFORNIA OIL FIELDS

	Nitrogen Oxides (as NO_2)		Carbon Monoxide		Hydrocarbons CH_4		Hydrocarbons TOC		Sulfur Dioxide††
	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	$\bar{x}$	Range	Estimated
Heater-Treater* Direct Fired 3-5 MMBtu/hr · burner size									
ppm, dry @ 3% O_2	43	21-77	2200	47-8700	864	neg.-3900	1070	1.70-6300	neg.
ng/J	24	11.6-45	760	17.2-23,000	125	neg.-700	150	0.25-900	0.26
lbs/MMBtu**	0.056	0.027-0.104	1.76	0.040-7.3	0.29	neg.-1.63	0.35	0.00057-2.1	0.0006
Heater-Treater† Pilot Light Only 3-5 MMBtu/hr · burner size									
ppm, dry @ 3% O_2	88	75-107	37,000	120-80,000	18,600	1250-39,000	37,000	1230-76,000	neg.
ng/J	41	17.2-65	5600	45-11,200	1680	260-3100	2400	189-4600	0.26
lbs/MMBtu	0.096	0.04-0.152	13	0.104-26	3.9	0.60-7.2	5.5	0.44-10.6	0.0006
Small Heaters - Indirect Fired§ 500,000 Btu/hr size Stack Gas Composition @ ~80% F.R.									
ppm, dry @ 3% O_2	52	29-77	12,400	60,000-77	59	0.5-107	79	4.7-132	neg.
ng/J	26	8.6-41	2400	25-11,200	9.0	0.099-19.4	9.0	0.65-18.1	0.26
lbs/MMBtu	0.060	0.020-0.096	5.5	0.058-26	0.021	0.00023-0.045	0.021	0.00151-0.042	0.0006
Small Heaters - Direct Fired# 500,000 Btu/hr size "Propane Fuel" Stack Gas Composition @ ~60% F.R.									
ppm, dry @ 3% O_2	47		290		62		1130		neg.
ng/J	32		12.0		14.2		198		0.26
lbs/MMBtu	0.074		0.028		0.033		0.46		0.0006

*Results indicate average emission factors developed from the testing of two 6-MMBtu/hr total, one 10-MMBtu/hr total, and one 8-MMBtu/hr total dual burner/firetube horizontal crude oil (oil-water emulsion) heaters. Fourteen tests on 6 burners over a firing rate range of 20% to 80% of capacity were performed. Fuel was either processed field or natural gas.

†Pilot light tests were performed on each burner of a dual burner heater.

§Results indicate average emission factors developed from the testing of two 500,000-Btu/hr single burner/firetube horizontal crude oil heater-treater and one 348,000 Btu/hr single burner/firetube, glycol reboiler. Five tests at approximately 40 to 80% load were performed. Fuel was processed field gas.

#Results based on the data obtained from one test performed at approximately 50% load. Heater is rated at 500,000 Btu/hr, fired on LPG, and of a single burner.

**Based on a HHV of approximately 1,000 Btu/scf.

††Based on a typical natural gas sulfur content of 2,000 grains per 10^6 scf as reported in AP-42, Section 1.4.1.

Tests conducted on five of the eight heaters showed that increasing the normal firing rate of a unit (operating at a higher load or percent of maximum heat input) had a 1) decreasing effect on the O_2 as expected; 2) increasing, decreasing and negligible effect on the CO depending on the starting and ending O_2 levels; 3) general increasing effect on the NO_x as expected; 4) negligible effect on the SSN measured except for one test where the SSN increased; and 5) decreasing or increasing effect on the levels of THC depending on the starting and ending concentrations of O_2 and CO measured. In general, if the low firing rate excess O_2 level was extremely high, as with unit number LHI-Left, the amount of excess combustion air as with unit number LHI-Left was tending to quench the combustion process producing high levels of CO and THC's. With an increase in the firing rate, the excess O_2 level would drop to a more reasonable level and the levels of CO and THC would drop and the NO_x would increase slightly. In contrast, if the low firing rate excess O_2 level was not exceptionally high as with unit number LHI-Right, an increase in firing rate would cause the O_2 to drop off to a lower than reasonable level causing the CO and THC levels to increase. The limited number of THC samples taken prevented a closer investigation of trends as a function of firing rate.

In summary, the tests results indicate that the levels of NO_x emitted from oil field service heaters and heater-treaters are low due primarily to the relatively low heat release rates of the metal in the units in conjunction with the long, lazy flame shapes observed. The test results also showed that the levels of CO, THC's and carbon (SSN) emitted can be quite high due to either a excess or deficiency of combustion air due to poor tuning or partially plugged air inlets. Operating a heater at a lower or higher firing rate was also found to have an unpredictable effect on the levels of CO, THC and carbon (SSN) produced. In contrast, increased firing rates generally increased the level of NO_x generated. Summarized below are the average operating conditions found and concentrations of gaseous species measured.

• Avg. A/F ratio	15.8	• Avg. CO @ 3% O_2	4500 ppm*
• Avg. SSN	2 - 3	• Avg. NO_x @ 3% O_2	45 ppm*
		• Avg. THC @ 3% O_2	
		-CH_4	550 ppm*
		-TOC	850 ppm*

The concentrations of SO_2 listed in Table 4.2-1 were calculated as was done for IC engines and are therefore, not listed. Also not listed was the average firing rate or load found for all the tested units. The reason for this is that under normal operation, there was no way to measure the fuel flow rate with the instruments on hand. However, what is presented in Table 4.2-1 are average daily emission rates for five of the eight units tested. These data can be used to approximate the actual emissions of each unit type for a normal work day, operating in an "on-off" mode.

4.2.2 Emission Factors

Presented in Table 4.2-2 is a list of emission factors for gas-fired oil field service heaters and heater treaters. These emission factors are based on the test results presented previously. Shown are the arithmetic average and range of emissions for NO_x, CO, THC as CH_4 and TOC, and SO_2.

Emissions are reported in units of ppm dry at 3 percent O_2, ng/J, and lb/MMBtu fired. Average daily emission rates in units of lb/day unit are presented along the bottom of Table 4.2-2.

The wide range in emission levels found for each pollutant listed was due primarily to the differences in A/F ratios measured on each unit.

*Reported on a dry basis