Petroleum Refinery Source Characterization and Emission Model for Residual Risk Assessment

Prepared for:

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Contract No. 68-D6-0014

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1.0 Model Overview

The Refinery Emission Model (REM) is an Access database model used to characterize hazardous air pollutant (HAP) emissions from all processes typically present at a petroleum refinery. The model has been designed to use reported emissions data, if they are available. When reported emissions data are not available, they are estimated using the best available data or algorithms (as described in Section 4), which are based on a variety of emission factors and calculation protocols developed and reported by the U.S. Environmental Protection Agency (EPA). Additional emission factors and calculation protocols were developed, as necessary, for a few emission sources. Emission factor development for these sources relied heavily on emissions reported by refineries in their Title V permit applications.

The overall database is based primarily on the information reported in the *Oil & Gas Journal* (OGJ) 2000 Worldwide Refining Survey (Stell, 2000a). This survey lists 155 refineries in the United States and it territories (Puerto Rico and the Virgin Islands). It also provides site-specific process charge or production capacities for 18 refinery process units at these refineries. Data collected by EPA in developing other standards for the petroleum refining industry were used to supplement the database.

Using these data and the algorithms detailed in Section 4, the REM provides source characteristics and HAP emission estimates for each of the following emission sources:

- Process heaters and boilers
- Flares/thermal oxidizers (includes marine vessel loading emissions)
- Wastewater collection and treatment systems
- Cooling towers
- Fugitive equipment leaks
- Tanks (both storage and process tanks)
- Truck and rail (product) loading operations
- Catalytic reforming unit (CRU) catalyst regeneration vents
- Catalytic cracking unit (CCU) catalyst regeneration vents
- Sulfur recovery units (SRU) or sulfur plant vents.

A draft approach to estimating emissions from miscellaneous process vents is also provided in Section 4, but it has not been added to the REM.

The REM output file is based on the general structure of the National Toxic Inventory (NTI) database. This database provides a separate record for each chemical from each emission source at a given refinery.

One of the compounds most likely to drive risk at petroleum refineries is benzene because of its prevalence in emissions from petroleum refineries and its relatively high unit risk factor. Table 1-1 provides a comparison of benzene emissions calculated by REM and those reported by the refineries in their Title V applications.

Based on the comparison of calculated and reported benzene emissions for these refineries, the REM estimates appear to be accurate within a factor of 2 for each refinery emission point and for the total refinery emissions. In every case, the REM estimates are higher than the reported emissions. This is generally due to the inclusion of emission estimates for cooling towers, combustion sources, and other emission sources that were not reported by most refineries in their Title V permit applications.

Most of the emission discrepancies greater than a factor of 2 are readily explainable. First, the emissions reported by the Marathon–Garyville Refinery are substantially lower than those reported for other similar-sized refineries. This refinery was very active in the Early Reduction Program[1] and has implemented measures to reduce emissions from wastewater collection and treatment systems, marine vessel loading operations, and cooling towers, according to refinery personnel during an EPA site visit (Zerbonia and Coburn, 1995). This refinery is one of only a few refineries (if not the only refinery) that achieved the 90 percent emission reduction required by the Early Reduction Program. As such, it is understandable why this refinery's emissions are out-of-line compared with the emissions of other similar-sized refineries and why the REM overestimates this refinery's emissions. Because so few refineries qualified under the Early Reduction Program, the frequency of an emission discrepancy caused by a refinery controlling emissions well beyond what is currently required by law is considered to be very low. From a different perspective, Marathon–Garyville's emissions suggest that emission-reduction measures are available that could achieve emission reductions of roughly 65 percent compared with current (typical) industry practices.

The other significant discrepancy in reported versus predicted emissions is for the Exxon–Chalmette refinery. This refinery operates an aromatics unit and produces toluene and xylene, but no benzene. The REM cannot distinguish among the specific aromatics that are produced, so it assumes benzene, toluene, and xylene (BTX) are all produced. The REM estimates 5 tons/yr of benzene emissions occur from the benzene product storage tanks. Excluding this 5 tons/yr of benzene emissions from the storage tank emission estimates for the Exxon–Chalmette refinery yields tank emissions that are roughly within a factor of 2, and it significantly improves the overall refinery emission estimate. The inability to distinguish among the specific aromatics produced is one of the most significant shortcomings of the REM (at least in terms of BTX) emission estimates. Aromatics units operate at 20 percent of the U.S. refineries; data collection efforts targeted to these aromatics units would significantly improve REM emission estimates (not only for storage tanks, but also for wastewater treatment and fugitive process equipment leaks).

[1] The Early Reduction Program under Section 112(i) allows a qualifying facility to defer compliance with Maximum Achievable Control Technology (MACT) standards for 6 years if it reduces HAP emissions by 90 percent (95 percent for hazardous particulate emissions) before the applicable MACT is proposed.

Table 1-1. Comparison of Preliminary REM Estimates and Benzene Emission Estimates by Source from Title V Permit Applications

Refinery	Crude Capacity (bbl/cd)	Benzene Emissions (tons/yr)							
		Title V Fugitives	REM[a] Fugitives	Title V WWT	REM[a] WWT	Title V Storage Tanks	REM[a] Storage Tanks	Title V Refinery Totals	REM[a] Refinery Total
Exxon, Baton Rouge	485,000	12.9	7.6	14.1	10.6	23.8	9.9	48	50
Citgo, Lake Charles	300,000	13.2	13.7	4.4	9.2	21.2	9.7	41	47
BP, Belle Chase	250,000	9.3	6.9	9.5	7.4	10.1	14.2	31	40
Marathon, Garyville[b]	232,000	2.0	5.8	3.6	7.7	1.8	4.4	9.5[b]	29
Shell, Norco	220,000	9.6	8.6	NR	7.0	15.7	4.6	28	30
Exxon, Chalmette	183,000	15.8[c]	10.3	NR[c]	7.1	1.5	8.8[d]	17	35
Murphy, Meraux	95,000	9.0	4.9	0.41	5.3	0.6	2.0	10	17
Valero, Krotz Springs	78,000	5.1	5.3	9.8	5.1	0.8	1.6	16	16
Pennzoil, Shreveport	46,000	3.0	4.7	3.1	5.0	1.5	0.9	8.4	12.6

NR = not reported
WWT = wastewater treatment
[a] Emissions from the REM prior to actual data override
[b] Marathon–Garyville Refinery is one of the few refineries that qualified under the Early Reduction Program
[c] Reported combined fugitive emissions for process equipment and wastewater
[d] This refinery has an aromatics unit but does not produce benzene; 5 tons/yr of the REM tank emissions are based on production of benzene from the aromatics unit

2.0 Inputs and Outputs

There are four basic input files used by REM:

1. The actual reported emission database file;
2. The overall facility process capacity/production rate database file;
3. Unit-specific database files (for certain processes for which data are available); and
4. The emission factor database files (one file per emission source).

The actual reported emissions database file currently contains emissions data for nine Louisiana refineries for which Title V applications were obtained. This database will expand as more data are collected from the refineries or state agencies.

The overall and process-specific production rate databases are based on production and process charge capacities as reported in the OGJ 2000 Worldwide Refining Survey (Stell, 2000a). Process charge or production capacities are provided in the refining survey for the following process units:

- Crude unit
- Vacuum distillation unit
- Coking unit
- Thermal processes (thermal cracking and visbreaking)
- Catalytic cracking unit
- Catalytic reforming unit
- Catalytic hydrocracking unit
- Catalytic hydrotreating unit
- Alkylation unit
- Polymerization/dimerization unit
- Aromatics unit
- Isomerization unit
- Lube plant
- Oxygenates unit
- Hydrogen plant
- Coke plant
- Sulfur plant
- Asphalt plant.

Some unit-specific information was available for CCUs, CRUs, and SRUs based on previous Maximum Achievable Control Technology (MACT) standard development efforts. These additional data, which include the number of units, the type of unit, and the control devices used, are included in the unit-specific database files.

The emission factor input files were developed using the available data or estimation algorithms that are detailed in Section 4. The emission factors generally are formatted to provide HAP-specific emission estimates per unit throughput.

The REM output file is based on the general structure of the NTI database. This database provides a separate record for each chemical from each emission source at a given refinery. Table 2-1 lists the field names and descriptions for the output database file.

Based on the 2000 Worldwide Refining Survey (Stell, 2000a), the REM contains input/output information for 155 refineries located in the United States, Puerto Rico, and the Virgin Islands. Table 2-2 provides a listing of the refineries included in the REM.

Based on the available emissions data, HAP emissions estimates could be developed for 64 specific HAPs from the refinery emission sources. The HAPs included in REM input/output files are listed in Table 2-3.

Table 2-1. Fields in the Petroleum Refinery Output Database File

Field	Data Type	Description
FacNum	Double	Unique facility ID number assigned by RTI, ranging from 1 to 155
NTI_ID1	Text	ID assigned to the facility in the 1996 NTI
NTI_ID2	Text	Second NTI ID when more than one ID was assigned to the same facility
SCC	Text	Source classification code[1]
SCC1_DESC	Text	Descriptor associated with first SCC digit
SCC3_DESC	Text	Descriptor associated with first three SCC digits
SCC6_DESC	Text	Descriptor associated with first six SCC digits
SCC8_DESC	Text	Descriptor associated with first eight SCC digits
AFSUNITS	Text	Units of measure associated with throughput—AIRS Facility Subsystem
MEASURE	Text	Units of measure associated with throughput
MATERIAL	Text	Material being measured
ACTION	Text	Action performed on the material
UnitID	Text	ID assigned to the process unit or group of units for which emissions are estimated
CASRN	Text	Chemical Abstract Service registration number for the chemical in the row
ChemName	Text	Name of the chemical for which emissions are estimated
Emissions	Double	Annual emissions of the chemical in tons per year
OpHours	Text	Number of hours per year that the process operates
Height	Text	Height of the emission point in feet

(continued)

Table 2-1. (continued)

Field	Data Type	Description
Diameter	Text	Diameter of the emission point in feet
Area	Text	Area of the emission point in square feet
Temperature	Text	Temperature of the emissions in degrees Farenheit
FlowRate	Text	Volumetric flow rate of the emissions in actual cubic feet per minute
Velocity	Text	Linear velocity of the emissions in feet per second
H	Text	Horizontal Universal Transverse Mercator (UTM) coordinate—specific to the emission point when available
V	Text	Vertical UTM coordinate—specific to the emission point when available
Lat	Double	Latitude (one value for the entire plant)
Long	Double	Longitude (one value for the entire plant)

[1] The number of digits provided depends on how the emission points are grouped. For example, tanks are assigned three digits (403) because one estimate of emissions was made for all types of tanks (fixed-roof, floating-roof, etc.). On the other hand, process heaters are very specific and use eight digits (30600106).

Table 2-2. List of Refineries Included in the REM

No.	Facility Name	City	State	Crude Capacity (bbl/day)
1	Coastal Mobile Refining Co.	Mobile Bay	AL	20,000
2	Hunt Refining Co.	Tuscaloosa	AL	43,225
3	Shell Oil Products Co.	Saraland	AL	85,000
4	BP (formerly ARCO Alaska, Inc.)	Prudhoe Bay	AK	15,000
5	BP (formerly ARCO Alaska, Inc.)	Kuparuk	AK	14,500
6	Petro Star, Inc.	North Pole	AK	15,000
7	Petro Star, Inc.	Valdez	AK	45,000
8	Tesoro Petroleum Corp.	Kenai	AK	72,000
9	Williams Co., Inc. (formerly Mapco Alaska Petroleum)	North Pole	AK	210,000
10	Berry Petroleum Co.	Stephens	AR	6,700
11	Cross Oil & Refining Co., Inc.	Smackover	AR	6,000
12	Lion Oil Co.	El Dorado	AR	55,000
13	Anchor Refining Co.	McKitrick	CA	10,000
14	BP (formerly Atlantic Richfield Co. (ARCO))	Carson	CA	260,000

(continued)

Table 2-2. (continued)

No.	Facility Name	City	State	Crude Capacity (bbl/day)
15	Chevron USA Products Co.	El Segundo	CA	260,000
16	Chevron USA Products Co.	Richmond	CA	225,000
17	Equilon (formerly Texaco)	Bakersfield	CA	61,750
18	Equilon (formerly Shell Oil Co.)	Martinez	CA	154,800
19	Equilon (formerly Texaco)	Wilmington	CA	98,500
20	ExxonMobil Corp. (formerly Mobil)	Torrance	CA	148,500
21	Golden Bear Oil Specialties	Oildale	CA	12,500
22	Greka Energy (formerly Santa Maria Refining)	Santa Maria	CA	10,000
23	Huntway Refining Co.	Benicia	CA	10,000
24	Huntway Refining Co.	Wilmington	CA	6,000
25	Kern Oil & Refining Co.	Bakersfield	CA	25,000
26	Paramount Petroleum Corp.	Paramount	CA	45,000
27	San Joaquin Refining Co., Inc.	Bakersfield	CA	24,300
28	Ten By, Inc.	Oxnard	CA	4,500
29	Tosco (formerly Unocal Corp.)	LA-Wilmington Carson	CA	131,000
30	Tosco (formerly Unocal Corp.)	SF - Rodeo & Santa Maria	CA	115,000
31	Ultramar Diamond Shamrock (formerly Tosco)	Golden Eagle	CA	168,000
32	Ultramar Diamond Shamrock	Wilmington	CA	78,000
33	Valero (formerly Exxon Co. USA)	Benicia	CA	135,000
34	World Oil Co. (formerly Lunday-Thagard Co.)	South Gate	CA	7,000
35	Conoco, Inc.	Commerce City	CO	57,500
36	Ultramar Diamond Shamrock (formerly Total Petroleum)	Denver	CO	28,000
37	Motiva Enterprises (formerly Star)	Delaware City	DE	152,000
38	Young Refining Corp.	Douglasville	GA	6,000
39	Chevron USA, Inc.	Barber's Point	HI	54,000
40	Tesoro Hawaii Petrol. (formerly BHP)	Kapolei	HI	95,000
41	Citgo Petrol. (formerly UNO-VEN)	Lemont	IL	158,650

(continued)

Table 2-2. (continued)

No.	Facility Name	City	State	Crude Capacity (bbl/day)
42	ExxonMobil Corp. (formerly Mobil)	Joliet	IL	230,500
43	Marathon Ashland Petrol.	Robinson	IL	192,000
44	Premcor Refining Group (formerly Clark Oil and Refining Corp.)	Blue Island	IL	76,000
45	Premcor Refining Group (formerly Clark Oil and Refining Corp.)	Hartford	IL	68,000
46	Tosco Refining (formerly Equilon, Wood River, & Shell Oil)	Wood River	IL	286,400
47	BP (formerly Amoco Oil Co.)	Whiting	IN	410,000
48	Countrymark Cooperative, Inc.	Mt. Vernon	IN	23,000
49	Laketon Refining Corp.	Laketon	IN	3,990
50	Cooperative Refining (formerly Farmland Industries, Inc.)	Coffeyville	KS	95,000
51	Cooperative Refining (formerly National Cooperative Refinery Association)	McPherson	KS	75,000
52	Frontier Oil Corp. (formerly El Dorado Refining, formerly Texaco)	El Dorado	KS	104,500
53	Marathon Ashland Petroleum LLC	Catlettsburg	KY	222,000
54	Somerset Refinery, Inc.	Somerset	KY	5,500
55	American International Refining, Inc.	Lake Charles	LA	30,000
56	Calcasieu Refining Co.	Lake Charles	LA	15,680
57	Calumet Lubricants Co.	Cotton Valley	LA	8,500
58	Calumet Lubricants Co.	Princeton	LA	9,500
59	Canal Refining Co.	Church Point	LA	30,000
60	Cit-Con Oil Corp.	Lake Charles	LA	0
61	Citgo Petroleum Corp.	Lake Charles	LA	307,325
62	Conoco, Inc.	Westlake	LA	245,000
63	ExxonMobil Corp. (formerly Exxon)	Baton Rouge	LA	485,000
64	ExxonMobil Corp. (formerly Mobil)	Chalmette	LA	182,500
65	Marathon Ashland Petroleum LLC	Garyville	LA	232,000
66	Motiva Enterprises (formerly Star)	Convent	LA	225,000

(continued)

Table 2-2. (continued)

No.	Facility Name	City	State	Crude Capacity (bbl/day)
67	Motiva Enterprises (formerly Shell Oil Co.)	Norco	LA	220,000
68	Murphy Oil USA, Inc.	Meraux	LA	95,000
69	Orion Refining Corp (formerlyTransAmerican Refining Corp)	Norco	LA	200,000
70	Pennzoil Products Co. (formerly Atlas Div. of)	Shreveport	LA	46,200
71	Placid Refining, Inc.	Port Allen	LA	48,000
72	Shell Chemical Co.	St. Rose	LA	55,000
73	Tosco Refining Co. (formerly BP Oil Co.)	Belle Chasse	LA	250,000
74	Valero (formerly Basis Petroleum, Inc.)	Krotz Springs	LA	78,000
75	Marathon Ashland Petrol. LLC	Detroit	MI	74,000
76	Koch Refining Co.	Rosemount	MN	290,000
77	Marathon Ashland Petrol. LLC	St. Paul Park	MN	70,000
78	Chevron USA, Inc.	Pascagoula	MS	295,000
79	Ergon Refining, Inc.	Vicksburg	MS	23,000
80	Southland Oil Co.	Lumberton	MS	5,800
81	Southland Oil Co.	Sandersville	MS	11,000
82	Cenex Harvest States	Laurel	MT	46,000
83	Conoco, Inc.	Billings	MT	55,100
84	ExxonMobil Corp. (formerly Exxon)	Billings	MT	58,000
85	Montana Refining Co.	Great Falls	MT	7,000
86	Foreland Refining Co. (formerly Petro Source Refining Partners)	Tonopah/Eagle Springs	NV	3,500
87	Amerada-Hess Corp.	Port Reading	NJ	0
88	Coastal Eagle Point Oil Co.	Westville	NJ	150,000
89	Tosco Refining Co. (formerly Bayway)	Linden	NJ	250,000
90	Valero Energy Corp. (formerly Mobil Oil)	Paulsboro	NJ	157,000
91	Giant Refining Co.	Bloomfield	NM	16,800
92	Giant Refining Co.	Gallup	NM	20,800
93	Navajo Refining Co.	Artesia	NM	60,000

(continued)

Table 2-2. (continued)

No.	Facility Name	City	State	Crude Capacity (bbl/day)
94	BP (formerly Amoco Oil Co.)	Mandan	ND	58,000
95	BP Oil Co.	Toledo	OH	152,000
96	Marathon Ashland Petrol. LLC	Canton	OH	73,000
97	Premcor Refining Group (formerly Clark Refining & Mrktg, formerly BP Oil Co.)	Lima	OH	165,000
98	Sunoco, Inc.	Toledo	OH	140,000
99	Conoco, Inc.	Ponca City	OK	174,000
100	Gary-Williams Energy Corp.	Wynnewood	OK	45,000
101	Sinclair Oil Corp.	Tulsa	OK	50,000
102	Sunoco, Inc.	Tulsa	OK	85,000
103	Ultramar/Diamond Shamrock (formerly Total Petroleum, Inc.)	Ardmore	OK	84,400
104	American Refining Group (formerly Witco Chemical Co.)	Bradford	PA	10,000
105	Sunoco, Inc.	Marcus Hook	PA	175,000
106	Sunoco (combined Sun & Chevron)	Phil. (Girard Pt & Pt Breeze)	PA	330,000
107	Tosco Refining Co. (formerly BP)	Trainer (Marcus Hook)	PA	180,000
108	United Refining Co.	Warren	PA	66,700
109	Williams Energy Services (formerly Mapco Petroleum, Inc.)	Memphis	TN	140,000
110	AGE Refining & Manufacturing	San Antonio	TX	10,000
111	Alon Israel (formerly Fina Oil & Chemical Co.)	Big Spring	TX	61,000
112	Atofina Petrochemicals, Inc. (formerly Fina Oil & Chemical Co.)	Port Arthur	TX	176,000
113	BP (formerly Amoco Oil Co.)	Texas City	TX	437,000
114	Chevron USA, Inc.	El Paso	TX	90,000
115	Citgo	Corpus Christi	TX	152,000
116	Coastal Refining & Marketing, Inc.	Corpus Christi	TX	100,000
117	Crown Central Petroleum Corp.	Pasadena	TX	100,000
118	ExxonMobil Oil Corp (formerly Exxon Co.)	Baytown	TX	508,000

(continued)

Table 2-2. (continued)

No.	Facility Name	City	State	Crude Capacity (bbl/day)
119	ExxonMobil Corp. (formerly Mobil)	Beaumont	TX	342,500
120	Koch Petroleum Group (includes SWest Refining)	Corpus Christi	TX	297,000
121	LaGloria Oil & Gas Co.	Tyler	TX	60,000
122	Lyondell-Citgo Refining Co.	Houston	TX	268,850
123	Marathon Ashland Petrol. LCC	Texas City	TX	72,000
124	Motiva Enterprises (formerly Star)	Port Arthur	TX	245,000
125	Phillips Petroleum Co.	Borger	TX	125,000
126	Phillips Petroleum Co.	Sweeny	TX	205,000
127	Premcor Refining Group (formerly Clark Oil)	Port Arthur	TX	225,000
128	Shell-Deer Park Refining Limited Partnership	Deer Park	TX	274,900
129	Trifinery Petrol. Srvc. (formerly Neste Trifinery)	Corpus Christi	TX	30,000
130	Ultramar/Diamond Shamrock Corp.	Three Rivers	TX	86,000
131	Ultramar/Diamond Shamrock Corp.	Sunray	TX	145,500
132	Valero Refining Co.	Corpus Christi	TX	94,100
133	Valero (formerly Basis Petroleum, Inc.)	Houston	TX	83,000
134	Valero (formerly Basis Petroleum, Inc.)	Texas City	TX	165,000
135	BP (formerly Amoco Oil Co.)	Salt Lake City	UT	53,000
136	Chevron USA	Salt Lake City	UT	45,000
137	Silver Eagle Refining, Inc. (formerly Inland Refining, formerly Crysen Refining)	Woods Cross	UT	12,500
138	Flying J (formerly Big West Oil Co.)	Salt Lake City	UT	25,000
139	Phillips Petroleum Co.	Woods Cross	UT	25,000
140	BP (formerly Amoco Oil Co.)	Yorktown	VA	58,600
141	BP (formerly Atlantic Richfield Co. (ARCO))	Ferndale	WA	222,720
142	Equilon Enterprises (formerly Texaco)	Anacortes	WA	145,200
143	Sound Refining, Inc.	Tacoma	WA	11,900
144	Tesoro (formerly Shell Oil Co.)	Anacortes	WA	108,200
145	Tosco Refining Co.	Ferndale	WA	89,000
146	US Oil & Refining Co.	Tacoma	WA	43,700

(continued)

Table 2-2. (continued)

No.	Facility Name	City	State	Crude Capacity (bbl/day)
147	Ergon-West Virginia, Inc. (formerly Quaker State Oil Refining Corp.)	Newell	WV	11,500
148	Murphy Oil USA, Inc.	Superior	WI	33,250
149	Frontier Oil & Refining Co.	Cheyenne	WY	40,500
150	Little America Refining Co.	Casper	WY	22,000
151	Sinclair Oil Corp.	Sinclair	WY	22,000
152	Wyoming Refining Co.	Newcastle	WY	12,500
153	Hovensa LLC (formerly Hess Oil)	St. Croix	V.Isl	525,000
154	Caribbean Petroleum Corp.	Bayamon	P.Rico	49,000
155	Sunoco, Inc.	Yabucoa	P.Rico	0

Table 2-3. Compounds in the Refinery Database

CASRN	Compound Name	CASRN	Compound Name
106990	1,3-Butadiene	57125	Cyanide
540841	2,2,4-Trimethylpentane	53703	Dibenzo(a,h)anthracene
91576	2-Methylnaphthalene	84742	Di-n-butylphthalate
83329	Acenaphthene	1746016	Dioxin TEQ
208968	Acenaphthylene	100414	Ethylbenzene
75070	Acetaldehyde	206440	Fluoranthene
107028	Acrolein	86737	Fluorene
107131	Acrylonitrile	50000	Formaldehyde
120127	Anthracene	57117449	HCDF
7440360	Antimony	7647010	HCl
7440382	Arsenic	74908	HCN
7440393	Barium	110543	Hexane
71432	Benzene	193395	Indeno(1,2,3-c,d)pyrene
56553	Benzo(a)anthracene	7439921	Lead
50328	Benzo(a)pyrene	7439965	Manganese

(continued)

Table 2-3. (continued)

CASRN	Compound Name	CASRN	Compound Name
205992	Benzo(b)fluoranthene	7439976	Mercury
192972	Benzo(e)pyrene	67561	Methanol
191242	Benzo(g,h,i)perylene	78933	Methyl ethyl ketone
207089	Benzo(k)fluoranthene	108101	Methyl isobutyl ketone
7440417	Beryllium**	1634044	Methyl tert-butyl ether
92524	Biphenyl	75092	Methylene chloride
117817	Bis(2-ethyl hexyl)phthalate	91203	Naphthalene
74839	Bromomethane	7440020	Nickel
7440439	Cadmium	57117314	PCDF
75150	Carbon disulfide	85018	Phenanthrene
463581	Carbonyl sulfide	108952	Phenol
7782505	Chlorine		POM(PNA/PAH)
18540299	Chromium (hex)**	129000	Pyrene
7440473	Chromium (total)	7782492	Selenium
218019	Chrysene	100425	Styrene
7440484	Cobalt	108883	Toluene
1319773	Cresols	1336363	Total PCBs
98828	Cumene	1330207	Xylene (Total)

** Emissions for these compounds were based only on nondetect limits and are, therefore, biased high.

3.0 Assumptions and Limitations

In addition to the information and data discussed in Section 2, the REM contains various assumptions, most of which are more effectively described on a source-specific basis. The more general model assumptions are discussed in this section; the assumptions made in developing source-specific emission characteristics and emission factors are discussed in the source-specific subsections in Section 4.

As described previously, emissions are generally estimated based on production and process charge capacities as reported in the OGJ 2000 Worldwide Refining Survey (Stell, 2000a). This approach leads to two assumptions. The first is that the 2000 Worldwide Refining Survey includes all known U.S. petroleum refineries. In reviewing other EPA databases, it appears that several small companies (pipeline stations, gas stations, home heating fuel distributors, etc.) occasionally list themselves using the SIC code of 2911 (Petroleum Refineries). The 1996 version of the NTI appears to contain many such facilities. The OGJ survey was considered to provide the best reference for facilities that were actually petroleum refineries. In some instances, two or three nearby/neighboring refineries, which were originally separate facilities, have come under the control of a single company. These refineries were subsequently listed in the OGJ survey as a single refinery, and the process totals reflect that of the total combined refinery. In these cases, the refineries are modeled as one large refinery. This treatment is generally consistent with the definition of a facility under the Clean Air Act (CAA) because the refineries are generally adjacent, and the combined refinery is included in a single contiguous facility boundary. However, not all of the combined refineries were contiguously located.

The second assumption is that all refinery processes are operating at 100 percent capacity. In general, this assumption is valid based on process capacity utilization trends (Lidderdale et al., 1995; EIA, 2000); crude capacity utilization rates reached 96 percent in May 2000 (FTC, 2001). Although certain processes, such as sulfur production, have capacity utilization rates that are substantially less than 100 percent (Stell, 2000b), for most petroleum refining processes, especially those that contribute significantly to the HAP emissions (especially those HAPs with high unit risk factors), the assumption of 100 percent capacity utilization provides an accurate assessment of actual operating rates.

The REM currently uses reported emissions data (from Title V permit applications) as a priority over the refinery model emission estimates *for a given emission source*. This assumes that the reported data are superior to the model estimates and are complete. If the reported emissions data file contains tank emission estimates for BTX, tank emissions are output for only those three chemicals, even though tank emission factors were developed for a dozen HAPs. Also, the degree of documentation of the reported data is widely variant, and some reported

emissions have no documented basis. It is quite likely that many of the reported emissions rates are not actually measured data, but emission model estimates made by the refinery. The refinery does have better knowledge of equipment type and counts to run its emission estimates, but these fixed emissions data have some level of uncertainty associated with them.

All of the emission estimates developed for the REM assume that the process units and emission controls, if present, are operating normally. The model does not estimate episodic emission events that may result from process upsets or control device malfunctions.

Because of the lack of process-specific source locations or configurations at the refineries and the emission characteristics of certain sources, three general area sources were defined: the process equipment area, the tank farm area, and the wastewater treatment area. Although the equipment leak emissions were calculated on a process-specific basis, these emissions were summed and used to estimate the total emissions from the process area. Similarly, refinery fuel gas (RFG) use in combustion sources was calculated on a process-specific basis, but the RFG use was summed for all heaters, with a separate sum for boilers, and these totals were used to determine the number of stacks at the refinery; these stacks were assumed to be uniformly distributed in the process area of the refinery.

Tank farms were assumed to be one large area emission source rather than a large number of individual tank point (for fixed-roof tanks with or without internal floating roofs) and area sources (for external floating-roof tanks). Half of the wastewater treatment emissions were assumed to occur from the process area (i.e., from the wastewater collection system), and half of the emissions from the wastewater treatment area.

4.0 Source Characteristics and Emission Estimates

This section describes the source characteristics and algorithms used to estimate HAP emissions from each specific emission source. The emission sources considered in the REM are discussed in the following subsections:

Section 4.1	Process heaters and boilers
Section 4.2	Flares/thermal oxidizers (includes emissions from marine vessel loading)
Section 4.3	Wastewater collection and treatment systems
Section 4.4	Cooling towers
Section 4.5	Fugitive equipment leaks
Section 4.6	Tanks (both storage and process tanks)
Section 4.7	Truck and rail (product) loading operations
Section 4.8	CRU catalyst regeneration vents
Section 4.9	CCU catalyst regeneration vents
Section 4.10	SRU or sulfur plant vents.

Although not included in the preliminary REM, miscellaneous process vents not included in the emission sources listed above are discussed in a final subsection, Section 4.11.

4.1 Process Heaters and Boilers

Process heaters and boilers are vent (point) sources that occur throughout the process area of the refinery. The size of the vent stack varies with the size of the heater or boiler (typically measured in terms of the rate fuel is burned). For petroleum refineries, nearly all refinery process heaters and boilers use RFG as the primary fuel. Boilers are used to generate steam for various refinery operations, and theses sources are generally localized, e.g., in the boiler plant. Process heaters are used to preheat feedstock for a given process or to heat distillation columns (the latter are often termed reboilers); these emission sources are typically localized at or near the process requiring the heater (or reboiler).

4.1.1 Emission Estimation Methodology

The American Petroleum Institute (API), in conjunction with the Western States Petroleum Association (WSPA), has conducted numerous emission source tests of combustion sources and has compiled emission factors to be used for refinery combustion sources (Hansell and England, 1998). Separate emission factors were developed for different combustion sources based on the type of source and fuel used. Emission factors compiled for boilers using RFG are presented in Table 4-1; the emission factors compiled for process heaters using RFG are presented in Table 4-2.

Table 4-1. Summary of Emission Factors for Boilers Firing Refinery Fuel Gas

Substance	CARB[a] Rating	Emission Factor (lb/MMBtu)				Tests	RSD, %	Uncer-tainty, %	Detect Ratio
		Mean	Median	Maximum	Minimum				
Arsenic	D3-v0	5.88E-07	6.46E-07	9.40E-07	1.78E-07	1	65.36	73.95	1
Beryllium	D3-v0	1.31E-07	1.31E-07	1.32E-07	1.29E-07	1	1.35	1.87	1
Cadmium	D3-v0	2.00E-06	1.70E-06	2.64E-06	1.67E-06	1	27.6	31.23	1
Chromium (hex)	C3-v0	6.32E-06	6.29E-06	8.78E-06	3.89E-06	1	38.7	43.79	0
Chromium (total)	C3-v1	1.04E-05	4.51E-06	2.49E-05	1.80E-06	1	121.39	137.36	1
Copper	D3-v0	5.32E-06	5.32E-06	6.51E-06	4.13E-06	1	31.59	43.78	1
Lead	D3-v0	2.05E-06	2.05E-06	2.10E-06	1.99E-06	1	3.87	5.36	1
Manganese	D3-v0	2.02E-06	2.02E-06	2.65E-06	1.38E-06	1	44.52	61.7	1
Mercury	D3-v0	2.72E-07	2.69E-07	3.22E-07	2.24E-07	1	18.19	20.58	0
Nickel	D3-v0	4.72E-06	4.72E-06	5.94E-06	3.51E-06	1	36.33	50.35	1
Selenium	D3-v0	1.73E-06	1.99E-06	2.39E-06	8.11E-07	1	47.44	53.68	0.16
Zinc	D3-v2	2.83E-03	3.22E-04	8.10E-03	7.83E-05	1	161.02	182.2	1
Acenaphthene	A3-v0	4.90E-09	4.65E-09	5.46E-09	4.59E-09	1	9.89	11.2	0.37
Acenaphthylene	A3-v0	2.13E-09	2.19E-09	2.19E-09	2.02E-09	1	4.43	5.01	0
Anthracene	A3-v0	1.89E-08	2.02E-08	3.28E-08	3.71E-09	1	77.14	87.3	1
Benzo(a)anthracene	A3-v0	1.53E-08	1.51E-08	2.07E-08	1.01E-08	1	34.78	39.35	1
Benzo(a)pyrene	A3-v0	2.86E-09	2.84E-09	3.71E-09	2.02E-09	1	29.49	33.37	0.76
Benzo(b)fluoranthene	A3-v0	5.65E-09	6.11E-09	6.99E-09	3.84E-09	1	28.79	32.57	1
Benzo(g,h,i)perylene	A3-v0	3.22E-09	3.28E-09	4.36E-09	2.02E-09	1	36.33	41.11	0.78
Benzo(k)fluoranthene	A3-v0	2.13E-09	2.19E-09	2.19E-09	2.02E-09	1	4.43	5.01	0
Chrysene	A3-v0	2.86E-09	2.19E-09	4.36E-09	2.02E-09	1	45.7	51.71	0.5
Dibenz(a,h)anthracene	A3-v0	2.13E-09	2.19E-09	2.19E-09	2.02E-09	1	4.43	5.01	0
Fluoranthene	A3-v0	3.56E-08	2.62E-08	6.11E-08	1.94E-08	1	62.95	71.23	1
Fluorene	A3-v0	8.19E-09	4.65E-09	1.53E-08	4.59E-09	1	75.53	85.46	1
Indeno(1,2,3-cd) pyrene	A3-v0	2.13E-09	2.19E-09	2.19E-09	2.02E-09	1	4.43	5.01	0
Naphthalene	A3-v0	1.72E-07	1.63E-07	2.03E-07	1.49E-07	1	16.13	18.25	1
Phenanthrene	A3-v0	4.71E-08	3.63E-08	7.43E-08	3.06E-08	1	50.5	57.15	1
Pyrene	A3-v0	5.00E-08	4.36E-08	6.99E-08	3.63E-08	1	35.35	40	1

(continued)

Table 4-1. (continued)

Substance	CARB[a] Rating	Emission Factor (lb/MMBtu)				Tests	RSD, %	Uncer-tainty, %	Detect Ratio
		Mean	Median	Maximum	Minimum				
Phenol	C2-v0	1.83E-06	7.04E-07	4.91E-06	5.45E-07	4	99.84	56.49	0.85
Acetaldehyde	C1-v3	3.01E-06	2.11E-06	1.01E-05	4.10E-09	5	95.45	48.3	1
Benzene	C1-v2	1.74E-04	5.03E-05	1.22E-03	2.86E-06	5	186.11	91.19	0.8
Formaldehyde	C1-v1	1.32E-05	1.16E-05	3.62E-05	2.81E-06	5	66.84	33.82	1
Hydrogen sulfide	A1-v1	2.21E-04	1.69E-04	5.93E-04	5.01E-05	5	92.8	45.47	0
Toluene	E2-v2	7.23E-04	7.25E-05	4.37E-03	3.59E-05	3	193	126.09	0.97

[a] CARB = California Air Resource Board

Table 4-2. Summary of Emission Factors for Process Heaters Firing Refinery Fuel Gas

Substance	CARB Rating	Emission Factor (lb/MMBtu)				Tests	RSD, %	Uncer-tainty, %	Detect Ratio
		Mean	Median	Maximum	Minimum				
Antimony	C3-v0	5.17E-07	5.84E-07	7.58E-07	2.10E-07	1	54.13	61.25	1
Arsenic	C3-v0	8.50E-07	9.90E-07	1.28E-06	2.84E-07	1	60.1	68	1
Barium	C3-v0	5.78E-06	5.78E-06	5.92E-06	5.63E-06	1	2.45	2.78	0
Beryllium	C3-v0	2.57E-07	2.57E-07	2.63E-07	2.50E-07	1	2.45	2.78	0
Cadmium	C3-v0	9.88E-07	9.65E-07	1.18E-06	8.15E-07	1	18.76	21.23	1
Chromium (hex)	C3-v0	2.17E-06	2.21E-06	2.24E-06	2.05E-06	1	4.62	5.23	0
Chromium (total)	C3-v0	1.07E-06	6.57E-07	1.93E-06	6.26E-07	1	69.39	78.52	0.6
Copper	C3-v0	4.21E-06	1.93E-06	9.39E-06	1.31E-06	1	106.76	120.81	1
Lead	C3-v0	4.89E-06	3.94E-06	7.51E-06	3.21E-06	1	47.03	53.22	1
Manganese	C3-v0	6.81E-06	6.26E-06	1.22E-05	1.97E-06	1	75.45	85.38	1
Mercury	C3-v0	1.80E-07	1.75E-07	1.93E-07	1.71E-07	1	6.49	7.34	0.36
Nickel	C3-v1	9.42E-06	1.31E-06	2.57E-05	1.29E-06	1	149.3	168.95	0.95
Phosphorus	C3-v0	6.42E-07	6.43E-07	6.57E-07	6.26E-07	1	2.45	2.78	0
Selenium	C3-v0	1.96E-08	2.03E-08	2.54E-08	1.32E-08	1	31.23	35.34	0.78
Silver	C3-v1	1.61E-06	1.31E-06	3.21E-06	3.14E-07	1	91.23	103.24	0.94
Thallium	C3-v0	5.78E-06	5.78E-06	5.92E-06	5.63E-06	1	2.45	2.78	0

(continued)

Table 4-2. (continued)

Substance	CARB Rating	Emission Factor (lb/MMBtu)				Tests	RSD, %	Uncer-tainty, %	Detect Ratio
		Mean	Median	Maximum	Minimum				
Zinc	C3-v0	2.08E-05	2.58E-05	2.83E-05	8.48E-06	1	51.72	58.53	1
Acenaphthene	A2-v0	2.36E-09	1.55E-09	5.61E-09	1.20E-09	4	69.14	40.86	0.95
Acenaphthylene	A2-v0	1.55E-09	1.25E-09	2.74E-09	1.02E-09	4	41.7	24.64	0.51
Anthracene	A2-v0	2.87E-09	2.30E-09	6.45E-09	1.09E-09	4	61.24	36.19	0.92
Benzo(a)anthracene	A1-v2	3.21E-08	5.40E-09	3.39E-07	1.05E-09	9	265.3	101.97	1
Benzo(a)pyrene	A1-v3	8.96E-08	1.73E-09	1.38E-06	1.02E-09	9	352.36	135.44	0.98
Benzo(b)fluoranthene	A1-v2	4.04E-08	3.31E-09	4.87E-07	1.02E-09	9	314.58	120.92	0.99
Benzo(g,h,i)perylene	A2-v0	1.17E-09	1.10E-09	1.40E-09	1.02E-09	4	11.55	6.82	0
Benzo(k)fluoranthene	A1-v2	2.41E-08	2.18E-09	2.96E-07	1.02E-09	9	310.01	119.16	0.96
Chrysene	A2-v0	1.63E-09	1.23E-09	4.79E-09	1.02E-09	4	66.84	39.5	0.63
Dibenz(a,h)anthracene	A1-v2	1.02E-08	1.60E-09	1.37E-07	5.93E-10	9	279.09	107.28	0
Fluoranthene	A2-v0	3.06E-09	3.14E-09	5.04E-09	1.85E-09	4	33.8	19.97	1
Fluorene	A2-v0	1.08E-08	8.77E-09	2.74E-08	2.96E-09	4	70.62	41.74	1
Indeno(1,2,3-cd) pyrene	A1-v3	1.03E-07	1.75E-09	1.42E-06	1.02E-09	9	343.01	131.85	0.99
Naphthalene	A2-v0	3.13E-07	2.61E-07	7.58E-07	1.19E-07	4	66.9	39.53	1
Phenanthrene	A2-v0	1.46E-08	1.50E-08	2.25E-08	6.91E-09	4	32.6	19.27	1
Pyrene	A2-v0	2.84E-09	2.72E-09	4.53E-09	1.87E-09	4	28.87	17.06	1
Ethylbenzene	A2-v1	3.02E-05	1.79E-05	1.03E-04	2.72E-06	4	104.65	59.21	0.51
Phenol	C1-v1	5.63E-06	3.14E-06	2.54E-05	2.84E-07	7	114.62	49.02	0.97
Acetaldehyde	B1-v3	1.53E-05	8.12E-06	8.55E-05	8.41E-08	8	126.3	50.53	0.88
Benzene	B1-v1	6.47E-05	5.49E-05	1.85E-04	2.54E-06	11	87.67	29.91	0.02
Formaldehyde	B1-v3	1.11E-04	1.90E-05	1.34E-03	7.67E-07	7	262.94	112.46	1
Hydrogen sulfide	A1-v1	2.92E-04	2.46E-04	8.04E-04	1.76E-05	7	75.53	32.3	0
Propylene	A2-v0	2.17E-06	2.22E-06	2.98E-06	1.08E-06	3	23.69	15.47	0.05
Toluene	D1-v2	1.07E-04	7.00E-05	9.19E-04	4.04E-06	11	148.57	50.69	0.55
Xylene (total)	A2-v1	3.73E-05	3.16E-05	1.08E-04	4.66E-06	4	99.32	56.19	0.6

The median emission factors presented in Tables 4-1 and 4-2 were used for the preliminary emission estimates from heaters and boilers. Upon further review, it is noted that several of the emission factors presented by the California Air Resource Board (CARB)/API are

based on method detection limits; consequently, all heater and boiler emission factors that have a detect ratio of 0 will provide emission estimates that are biased high. For example, the hexavalent chromium emission factor, which is based on nondetect values, is higher than the median total chromium emission factor. Consequently, additional data are needed to develop accurate emission factors for the compounds with a zero-detect ratio.

To use the CARB/API emission factors, RFG usage rates are needed. Data on combustion sources were available from selected Louisiana refineries' Title V applications. These data confirmed that RFG is used almost exclusively to fuel process heaters and boilers. These data also established a means to estimate the RFG usage rates of a specific refinery process based on the process capacity. The RFG usage rates reported in the Title V applications were sorted by emission source. The total RFG usage for a given process, for example the CRU, was calculated and divided by the total CRU capacity (as reported in Stell (2000a)) to calculate an RFG usage rate per unit capacity factor. Process-specific RFG usage rate factors were compared for different Louisiana refineries, and a representative factor was selected (typically the highest of the median or average); Table 4-3 summarizes the process-specific RFG usage rate factors calculated for the Louisiana refineries reporting combustion fuel usage rates in their Title V permit applications and the emission factor selected from these data. In general, the mean value was used unless the range of calculated fuel use factors spanned an order of magnitude or if one value appeared to be incongruent. Median and log-mean average values were also calculated. Mean, median, and log-mean values were also calculated with the apparent incongruent value omitted, and a value was selected that appeared to best represent the limited data available.

Table 4-3. Development of Fuel Use Factors

Plant	City	State	Process for Fuel Use Factor	Process Capacity (bbl/cd)	Fuel Use Factor (MMBtu/bbl)		Comment
					Calculated	Selected	
BP-Alliance	Belle Chase	LA	Alkylation	38,000	0.0586	0.217	median
ExxonMobil	Chalmette	LA	Alkylation	12,500	0.2074		
Marathon Oil	Garyville	LA	Alkylation	28,500	0.2265		
Murphy Oil	Meraux	LA	Alkylation	7,650	0.5145		
BP-Alliance	Belle Chase	LA	Aromatics	17,800	0.0998	0.0998	
Marathon Oil	Garyville	LA	Asphalt	39,900	0.1329	0.190	mean
Pennzoil	Shreveport	LA	Asphalt	540	0.2471		
ExxonMobil	Chalmette	LA	CO Boiler	68,000	0.1129	0.219	mean
Pennzoil	Shreveport	LA	CO Boiler	10,800	0.3251		
BP-Alliance	Belle Chase	LA	Coking	25,200	0.0200	0.0942	mean
ExxonMobil	Chalmette	LA	Coking	32,500	0.1684		
Exxon	Baton Rouge	LA	CRU	70,000	0.3576	0.467	median

(continued)

Table 4-3. (continued)

Plant	City	State	Process for Fuel Use Factor	Process Capacity (bbl/cd)	Fuel Use Factor (MMBtu/bbl)		Comment
					Calculated	Selected	
Marathon Oil	Garyville	LA	CRU	42,800	0.4441		
BP-Alliance	Belle Chase	LA	CRU	42,000	0.4476		
Murphy Oil	Meraux	LA	CRU	16,200	0.4859		
ExxonMobil	Chalmette	LA	CRU	46,000	0.5044		
Pennzoil	Shreveport	LA	CRU	8,000	0.5064		
Citgo	Lake Charles	LA	Crude	307,325	0.0282	0.0873	mean w/o low #
ExxonMobil	Chalmette	LA	Crude	182,500	0.0826		
Pennzoil	Shreveport	LA	Crude	46,200	0.0836		
Marathon Oil	Garyville	LA	Crude	232,000	0.0861		
BP-Alliance	Belle Chase	LA	Crude	250,000	0.0888		
Murphy Oil	Meraux	LA	Crude	95,000	0.0954		
Murphy Oil	Meraux	LA	FCCU[a]	34,200	0.0229	0.0505	median
Marathon Oil	Garyville	LA	FCCU	104,500	0.0505		
ExxonMobil	Chalmette	LA	FCCU	68,000	0.0551		
ExxonMobil	Chalmette	LA	Hydrocrack	18,500	0.0889	0.105	mean
ExxonMobil	Chalmette	LA	Hydrocrack	18,500	0.1204		
Marathon Oil	Garyville	LA	Hydrotreat	181,500	0.0043	0.0179	mean w/o low & high values
BP-Alliance	Belle Chase	LA	Hydrotreat	112,000	0.0153		
Murphy Oil	Meraux	LA	Hydrotreat	58,050	0.0179		
ExxonMobil	Chalmette	LA	Hydrotreat	111,500	0.0189		
Exxon	Baton Rouge	LA	Hydrotreat	299,500	0.0193		
Pennzoil	Shreveport	LA	Hydrotreat	21,560	0.0499		
ExxonMobil	Chalmette	LA	Isom	9,500	0.1511	0.151	
Pennzoil	Shreveport	LA	Lubes	7,650	0.3683	0.368	
Marathon Oil	Garyville	LA	Boiler/Misc	232,000	0.0569	0.137	logmean
Exxon	Baton Rouge	LA	Boiler/Misc	485,000	0.1018		
Murphy Oil	Meraux	LA	Boiler/Misc	95,000	0.1262		
ExxonMobil	Chalmette	LA	Boiler/Misc	182,500	0.1855		
Pennzoil	Shreveport	LA	Boiler/Misc	46,200	0.3514		

(continued)

Table 4-3. (continued)

Plant	City	State	Process for Fuel Use Factor	Process Capacity (bbl/cd)	Fuel Use Factor (MMBtu/bbl)		Comment
					Calculated	Selected	
Exxon	Baton Rouge	LA	SRU	675[b]	1.9911[c]	3.08[c]	mean w/o high
ExxonMobil	Chalmette	LA	SRU	465[b]	2.4103[c]		
BP-Alliance	Belle Chase	LA	SRU	70[b]	3.8057[c]		
Murphy Oil	Meraux	LA	SRU	120[b]	4.1000[c]		
Pennzoil	Shreveport	LA	SRU	10[b]	15.1200[c]		
ExxonMobil	Chalmette	LA	Vacuum	102,000	0.0424	0.0838	median
Pennzoil	Shreveport	LA	Vacuum	23,085	0.0438		
Marathon Oil	Garyville	LA	Vacuum	118,800	0.0687		
Murphy Oil	Meraux	LA	Vacuum	47,500	0.0990		
BP-Alliance	Belle Chase	LA	Vacuum	92,000	0.1137		
Citgo	Lake Charles	LA	Vacuum	79,800	0.1504		

[a] FCCU = fluid CCU
[b] Capacity in long-tons/cd
[c] Fuel use factor in MMBtu/long-ton

Unclassified or miscellaneous RFG combustion sources were classified together with boilers to develop an overall boiler/miscellaneous RFG usage rate factor (based on crude throughput), and the boiler emission factors were applied to this combined group. Process heater emission factors were applied for all other RFG fuel usage rates. Table 4-4 provides a sample calculation of process heater and boiler emission estimates for benzene from a model refinery.

4.1.2 Source Characteristics

Data on combustion sources using RFG as reported in the Louisiana Title V applications were reviewed to develop process heater and boiler vent characteristics. The summary statistics for the process heater and boiler source vents are presented in Table 4-5. Based on these statistics, all process heater stacks were assumed to be 128 ft high and to operate at a stack temperature of 550°F. Process boilers were assumed to be 65 ft high and to operate at a stack temperature of 350°F.

Because the process heater fuel use was calculated on a process-specific basis, the number of process vents was initially going to be calculated on a process-specific basis (e.g., four vents per CRU, one vent for most other processes, three to four boiler vents, etc.). However, because no information was available to locate the process heater vents for most of the refineries and because uniform stack height and temperatures were assumed, the total RFG use rate for process heaters was calculated. A simple algorithm was developed to estimate the number of stacks based on the total RFG use rate by assuming the standard process heater burned

Table 4-4. Sample Calculation for Process Heaters and Boilers

Process	A Capacity (bbl/cd)	B Fuel Use Factor (MMBtu/bbl)	C = A×B×365 Fuel Use Rate (MMBtu/yr)	D Benzene Emission Factor (lb/MMBtu)	E = C×D/2000 Emission Rate (tons/yr)
Heaters					
Crude	100,000	0.0873	3,186,450	5.49E-5	0.087
Vacuum	50,000	0.0838	1,529,350	5.49E-5	0.042
Coking	15,000	0.0942	515,745	5.49E-5	0.014
Visbreaking	5,000	0.0942[c]	171,915	5.49E-5	0.005
CCU	35,000	0.0505	645,138	5.49E-5	0.018
CRU	25,000	0.467	4,261,375	5.49E-5	0.117
Hydrocracking	5,000	0.105	191,625	5.49E-5	0.005
Hydrotreat	50,000	0.0179	326,675	5.49E-5	0.009
Alkylation	5,000	0.217	396,025	5.49E-5	0.011
Aromatics	10,000	0.0998	364,270	5.49E-5	0.010
Isomerization	5,000	0.151	275,575	5.49E-5	0.008
Lubes	2,000	0.368	268,640	5.49E-5	0.007
SRU	100[a]	3.08[b]	112,420	5.49E-5	0.003
Asphalt	5,000	0.190	346,750	5.49E-5	0.010
	Subtotal for Process Heaters:		12,591,953	5.49E-5	0.346
Boilers					
Crude	100,000	0.137	5,000,500	5.03E-5	0.126
				Total for Process Heaters and Boilers:	**0.471**

[a] Capacity in long-tons/cd
[b] Fuel use factor in MMBtu/long-ton
[c] Assumed to be the same fuel use factor as coking

Table 4-5. Summary Statistics for Process Heater and Boiler Stacks

Type	Stat	Ht (ft)	Dia (ft)	T (°F)	ft/s	acfm
Heaters and Reboilers	Mean	129	6	600	24	38,800
	Median	128	5.3	550	18	23,600
	Std Dev.	53	3	215	24	44,600
	Minimum	24	1.5	140	0.3	37
	Maximum	257	15	1200	222	295,000
Boilers	Mean	89	6.5	500	27	60,100
	Median	64	6	340	20	41,800
	Std Dev.	59	2.8	325	16	48,100
	Minimum	25	3.5	270	11	7,300
	Maximum	205	13	1100	50	156,000

100 MMBtu/hr of RFG (2,400 MMBtu/cd), which translates to roughly 45,000 acfm at 550°F. Based on analysis of the flow rate data and fuel use rate data, along with theoretical calculations, a flow rate factor of 235 scfm per MMBtu/hr was determined (standard conditions defined as 1 atmosphere and 68°F). This flow rate factor was used to determine the process heater (or boiler) vent flow rate. The mean process heater stack diameter of 6 ft was used because the assumed flow rate per stack was a slightly larger-than-average stack flow rate.

This fixed-stack method was satisfactory for large refineries but provided single-stack estimates for small refineries. Consequently, the fixed-stack method was altered slightly so that all refineries had at least two process heater stacks. The final algorithm for determining the number of stacks for process heaters (PH) is as follows:

If PH RFG use is	**Then the number of PH stacks is**
< 1,800 MMBtu/cd,	2.
≥ 1,800 MMBtu/cd but < 4,200 MMBtu/cd,	(total PH RFG use)/1200 rounded to the nearest integer.
>4,200 MMBtu/cd,	(total PH RFG use)/2400 rounded to the nearest integer.

For boilers, three or four boiler stack vents were assumed per refinery. Refineries with less than 7,200 MMBtu/cd (300 MMBtu/hr, or approximately 50,000 bbl/cd crude capacity) were assumed to have three boilers and three boiler stacks; all other were assumed to have four boilers

and four boiler stacks. Because the boiler stack flow rates for large refineries could vary widely based on the essentially fixed number of boiler stacks, two different model boiler stack diameters were used for the large refineries. Boilers processing less than 4,800 MMBtu/cd per boiler were assumed to have 5 ft diameter stacks; boilers processing 4,800 MMBtu/cd per boiler or more were assumed to have 7.5 ft diameter stacks.

For both process heater and boiler stacks, the flow rate was calculated using Equation 4-1. The stack velocity was calculated based on the flow rate and stack diameter using Equation 4-2.

$$Q_{stack} = \frac{235 \text{ scfm}}{\text{MMBtu}} \times \frac{(460 + T_{stack})}{528} \qquad \textbf{4-1}$$

where

Q_{stack} = flow rate of stack (acfm)
T_{stack} = temperature of stack (°F)

$$V_{stack} = \frac{Q_{stack}}{\pi\left(\frac{d_{stack}}{2}\right)^2} \times \frac{1 \text{ min}}{60 \text{ sec}} \qquad \textbf{4-2}$$

where

V_{stack} = velocity of stack emissions (ft/sec)
d_{stack} = diameter of stack (ft)

Based on this methodology, the average model process heater stack (one model stack per refinery for all petroleum refineries) has a flow rate of 39,500 acfm and an average stack velocity of 23 ft/sec. Similarly, the average model boiler stack (one model stack per refinery for all petroleum refineries) has a flow rate of 58,000 acfm and an average stack velocity of 30 ft/sec.

4.1.3 Uncertainty in Estimates

The primary uncertainties are in the emission factors and the fuel use factors; there are also uncertainties in the number and characteristics of stacks. Statistics for the emission factors are provided in Tables 4-1 and 4-2. Care should be taken in using the uncertainties associated with the metals analyses because only one test was performed for process heaters and only one for boilers. Consequently, the statistics for metals presented in these tables illustrate the uncertainty and variability of a single process in the very short term. In general, the emission factors employed are considered central tendency values. However, for compounds with a detect ratio of zero (or close to zero), the emission factors are based on the analytical detection limits. Therefore, the emission factors for these compounds are biased high.

Because both process heaters and boilers are large combustion units firing the same fuel, the process heater and boiler emission factors are expected to be similar. It is encouraging to see that the metal emission factors developed for process heaters and for boilers (i.e., two separate tests) resulted in median or average emission factors that are generally within a factor of 2 or 3. A more complete analysis of uncertainty can be made by reviewing the uncertainties associated with the emission factors for VOCs for both process heaters and boilers and for the polycyclic aromatic hydrocarbons (PAHs) for process heaters. By evaluating the standard deviations for the emission factors for these chemicals, by comparing the median and average values within a test group, and by comparing the same central tendency indicator across test groups (i.e., process heaters versus boilers), the data provide compelling evidence that the central tendency emission factors are accurate within a factor of 2 or 3.

As presented in Tables 4-1 and 4-2, the maximum and minimum values represent the results of a single test run and not the results of a single source test (three-run average emission factor). As such, the maximum and minimum "emission factors" likely accentuate the variability of the process and the test methods rather than characterizing true process emissions variability. For example, in a single test run (see emission factors for metals where the detect ratio is 1), the maximum and minimum values roughly span an order of magnitude. These single sampling events provide an assessment of the short-term variations in process operations and uncertainties associated with the process emissions, but they may not provide good measures of long-term emission variablity. Nonetheless, based on the data presented in Tables 4-1 and 4-2, the high and low extreme values are roughly one order of magnitude greater than or less than the median value, respectively.

Although very limited data were used to develop the RFG use factors, with some fuel use factors based on single observations, only three processes significantly contribute to the overall fuel use rates for most refineries. As seen in the sample calculation for a "model" refinery presented in Table 4-4, CRU process heaters have the highest fuel use factor and generally dominate the process heater fuel usage. This was expected because the CRU is an endothermic reaction carried out in three to four reactors in series; before/between each reactor, the process stream is heated in a process heater to raise (or re-raise) the temperature of the process stream prior to the next reactor. The other major contributors to the refineries' fuel usage are the crude heaters and the boilers (which includes miscellaneous combustion vents) primarily because crude capacity is generally significantly larger than other process capacities. Therefore, the best measure of the accuracies and uncertainties associated with the overall RFG usage rates is the fuel usage factors developed for these three contributors.

Based on the data presented in Table 4-3, the fuel use factors for crude and CRU process heaters are very consistent. For CRUs, the factors range from 0.36 to 0.51; excluding the apparently low value, the range is very tight (0.44 to 0.51). Based on the energy requirements of the CRU, this tight range of fuel use factors is expected. Similarly, the crude unit process heater fuel use factors are expected to be consistent because the energy required to preheat the crude and operate the atmospheric distillation column should be universal for all refineries. Omitting the uniquely low value, the crude process heater fuel use factors range only from 0.83 to 0.95.

The boiler (and miscellaneous combustion source) fuel use factors exhibit a broader range of values than the crude and CRU process heaters; the high-low values differ from the central tendency value by a factor of 2.5. Although this may be partially due to differences in how refineries characterized their emission sources (i.e., which sources could be attributed to specific processes and which were included as miscellaneous sources), a given refinery may likely have significantly different steam generation and use requirements that affect the magnitude of its boiler plant (e.g., whether the CCU vent stream is used to generate steam). Consequently, the boiler fuel use rate factors are likely accurate only to a factor of 2 or 3. However, because the boiler contributes roughly 30 percent of the total RFG usage, the overall refinery fuel use rate is more certain, based on the tight range of factors for crude and CRU process heaters. The overall fuel usage rate for a given refinery is expected to be within ±50 percent. (Based on the similarity of emission factors for process heaters and boilers, minimal uncertainty is introduced by including miscellaneous RFG combustion sources with the boiler fuel use estimates.)

In summary, the emission factors are estimated to be accurate within a factor of 2 to 3, and the overall fuel usage rate for a given refinery is expected to be within ±50 percent. Taken together, the combined uncertainty of the process heater and boiler emission estimates is roughly a factor of 3 to 5. This uncertainty directly affects the emission estimates of the PAHs; other sources of PAH emissions are minor compared to the combustion sources. Process heater and boiler emissions of volatile organic HAPs are a very small contributor to the refinery's overall emissions of volatile organic HAPs. Metal HAP emissions from combustion sources have a direct impact on the total metal HAP emissions for refineries that do not have a CCU. For refineries with CCUs, the CCU metal HAP emissions are generally a factor of 2 to 5 times higher than the process heater and boiler emission estimates, so that the uncertainties in the risk associated with metal HAP emissions are more closely linked to the uncertainties in the CCU emission estimates.

4.2 Flares and Thermal Oxidizers

Flares and thermal oxidizers are used at petroleum refineries to destroy organic compounds in vapor streams of purged products or waste products that are vented from various processes. For example, flares are commonly used on the vapor recovery system associated with marine vessel loading and some process vents, and thermal oxidizers are used to destroy volatile organic compounds (VOCs) from enclosed wastewater treatment systems. Most flares have a natural gas pilot flame and use the fuel value of the vapor to sustain combustion. Thermal oxidizers (vapor incinerators) often use natural gas or other fuel to destroy vapors that often would not support combustion alone.

4.2.1 Emission Estimation Methodology

Accurate estimates of emissions from flares are difficult to obtain because they do not lend themselves to conventional emission testing techniques and only a few attempts have been made to characterize flare emissions. Some EPA tests have been attempted, and the results were used in AP-42 (U.S. EPA, 1995a; Section 13.5) to estimate a destruction efficiency of 98 percent

Table 4-6. Estimates of HAP Emissions from Flares and Thermal Oxidizers from Title V Permit Applications

Company	Crude Capacity (bbl/day)	Tons per Year							
		Benzene	Toluene	Xylene	Methyl t-butyl ether	Hexane	Formaldehyde	Ethyl benzene	1,3 Butadiene
Pennzoil	46,000	0.69	3.51	1.98		0.74		0.51	
Valero	78,000					1.56			0.09
Murphy	95,000	0.25	1.32	0.57	2.57	0.18	0.144	0.012	
Shell	220,000	2.4	0.36	0.06		24.2		0.01	9.31
Marathon	232,000	2.19	8.76	12.1		14.7	0.245	0.027	
BP	250,000	4.94	0.41	0.4	5.6	1.38		0.078	
Citgo	300,000	1.49	0.28	0.07	0.01	0.45		0.01	
		Emission Factor (tpy/bbl/day)							
Company	Crude Capacity (bbl/day	Benzene	Toluene	Xylene	Methyl t-butyl ether	Hexane	Formaldehyde	Ethyl benzene	1,3 Butadiene
Pennzoil	46,000	1.5E-05	7.6E-05	4.3E-05		1.6E-05		1.1E-05	
Valero	78,000					2.0E-05			1.2E-06
Murphy	95,000	2.7E-06	1.4E-05	6.0E-06	2.7E-05	1.9E-06	1.5E-06	1.3E-07	
Shell	220,000	1.1E-05	1.6E-06	2.7E-07		1.1E-04		4.5E-08	4.2E-05
Marathon	232,000	9.5E-06	3.8E-05	5.2E-05		6.4E-05	1.1E-06	1.2E-07	
BP-Alliance	250,000	2.0E-05	1.6E-06	1.6E-06	2.2E-05	5.5E-06		3.1E-07	
Citgo	300,000	5.0E-06	9.3E-07	2.3E-07	3.3E-08	1.5E-06		3.3E-08	
	Mean	1.0E-05	2.2E-05	1.7E-05	1.6E-05	3.1E-05	1.3E-06	2.0E-06	2.2E-05
	Median	1.0E-05	7.7E-06	3.8E-06	2.2E-05	1.6E-05	1.3E-06	1.2E-07	2.2E-05
Recommendation		**1 E-5**	**2 E-5**	**2 E-5**	**2 E-5**	**3 E-5**	**1 E-6**	**2 E-6**	**2 E-5**

and an emission factor of 0.14 lb total hydrocarbons per million Btu. This emission factor requires site-specific knowledge of the energy consumption of each flare, and the total hydrocarbons must be speciated to obtain estimates of HAP emissions. There are insufficient data to apply this technique to each of the 155 petroleum refineries.

Site-specific estimates, however, were obtained for seven Louisiana refineries from their Title V permit applications and are summarized in Table 4-6. The company estimates were generated using AP-42 procedures and, generally, speciation based on the vapor composition.

The estimates for BP-Belle Chasse (now Tosco) were accompanied by the most complete description of how they were done. A summary is provided below for the flare associated with marine vessel loading:

> *First, a vessel and material-specific emission factor is generated from the AP-42 methodology (Section 5.2) for loading petroleum liquid. Then, the total VOC emission rates are calculated by multiplying the appropriate emission factor by the product throughput. Speciated emissions of the VOC are calculated by multiplying the species weight (from site-specific composition data) by the total VOC emission rate. The heat input is calculated from the fuel usage rate and vapor heating value. Finally, VOC and species emissions are calculated from the AP-42 procedures for flares (Section 13.5).*

The best information on hand to estimate emissions from flares and thermal oxidizers is the site-specific estimates shown in Table 4-6. These results were extrapolated to other refineries by assuming that emissions from flares are proportional to the size of the refineries, i.e., larger refineries generate and burn more waste vapors in flares than do small refineries, assuming that operating practices are equivalent. The emission rates were normalized by the crude oil capacity to generate emission factors in tpy of HAP per barrel (bbl) of crude oil capacity. The recommended emission factors are shown in the bottom half of Table 4-6, and most are within an order of magnitude of the extreme values that were derived.

The application of the emission factor is straightforward, as illustrated below for benzene for a refinery with a capacity of 100,000 bbl/day:

$$\text{Benzene emissions (tpy)} = 100{,}000 \text{ bbl/day} \times 1\text{E-}5 \text{ tpy/bbl/day} = 1.0 \text{ tpy}.$$

4.2.2 Source Characteristics

Site-specific information was obtained for 27 flares and thermal oxidizers at seven refineries. The number of flares at each facility is given in Table 4-7. The larger refineries appear to have more than smaller refineries. To extrapolate to other refineries, a total of four flares were assigned to refineries less than 200,000 bbl/day capacity, and a total of six (four flares and two thermal oxidizers) were assigned for the larger refineries.

Source characteristics for flares and thermal oxidizers are also given in Table 4-7. All of the flares and thermal oxidizers are elevated (i.e., no ground-level flares were reported). Default values were chosen from the median values of 150 ft in height, 4 ft in diameter, and a temperature of 1,600°F. To estimate a default volumetric flow rate, the reported flow rates were examined and normalized by crude oil capacity. A value of 5 acfm per bbl/day was used to estimate volumetric flow rate. The linear velocity (ft/s) was then calculated from the volumetric flow rate, diameter, and number of flares at each plant.

4.2.3 Uncertainty in Estimates

As discussed earlier, emission estimates for flares are highly uncertain because the emissions are difficult to impossible to measure. The emission factors derived in this approach

introduce variability when they are applied to other refineries. Even if the site-specific estimates in Table 4-6 are accurate, there can be an order of magnitude of variability in applying these site-specific estimates to other refineries for which there are no data. However, the emission factors are a best estimate of the midrange value, and no attempt was made to bias them high or low. In addition, the site-specific emission estimates for flares indicates they are not a significant source of emissions relative to other sources, such as fugitive equipment leaks, wastewater, and storage

Table 4-7. Source Characteristics for Flares and Thermal Oxidizers (from Title V permit applications)

Plant	City	Crude(bbl/day)	Number of Each	
			Thermal Oxidizers	Flares
Pennzoil	Shreveport	46,000	Not reported	4
Murphy Oil	Meraux	95,000	Not reported	4
ExxonMobile	Chalmette	183,000	2	3
Marathon Oil	Garyville	232,000	3	3
BP-Alliance	Belle Chase	250,000	2	2
Citgo	Lake Charles	300,000	Not reported	4
Recommendation	**< 200,000 bbl/day**		**0**	**4**
	≥ 200,000 bbl/day		**2**	**4**

Parameter	Height (ft)	Diameter (ft)	Temperature (°F)
Mean	134	6	1400
Median	**150**	**4**	**1600**
Standard Deviation	76	7	560
Minimum	25	0.3	200
Maximum	300	35	2400

Plant	acfm	bbl/day	cfm/bbl/day
Pennzoil	137,883	46,000	3.0
Murphy Oil	72,926	95,000	0.8
Shell	2,527,937	220,000	11.5
Marathon Oil	2,172,320	232,000	9.4
Exxon	605,000	485,000	1.2
		Average	**5.2**

tanks; consequently, the error in flare emissions should not result directly in large errors for the total facility emissions.

Several factors affect the uncertainty in emission estimates for flares. These factors include the HAP concentration in the vapor being flared, its variability, the destruction efficiency, formation of products of incomplete combustion, combustion conditions, and how uniformly they are maintained.

For the source characteristics, the information in Table 4-7 appears to be a reasonable sample, and the refinery size spans an order of magnitude (from about 50,000 to 500,000 bbl/day). Consequently, the statistical summary in Table 4-7 should provide insight into the variability of source characteristics.

4.3 Wastewater Collection and Treatment Systems

The wastewater treatment plant is typically a collection of treatment processes located in a common area and generally distinct from the process area. The wastewater treatment plant receives wastewater from the oil-water separator and various process wastewater and storm water collection points contained in the process area. Previous experience and emission modeling of wastewater collection and treatment suggest that a large portion of the emissions from wastewater occur during the collection phase. Emissions from both the collection and treatment of wastewater are subject to the requirements of the Benzene Waste Operations National Emission Standard for Hazardous Air Pollutants (NESHAP) (40 CFR, Part 61, Subpart FF). All refineries that have more than 10 megagrams per year (Mg/yr) of benzene in their wastewater are required under this rule to employ certain wastewater collection and treatment equipment to reduce the emissions of benzene.

4.3.1 Emission Estimation Methodology

The "uncontrolled" or pre-Benzene Waste Operations NESHAP (pre-BWON) emissions were estimated following the methodology described in EPA's *Locating and Estimating Air Emissions from Sources of Benzene* (hereafter, the Benzene L&E document; U.S. EPA, 1998a). This methodology provides estimates of the amount of wastewater produced per unit throughput of various refinery processes (average flow factors) along with an estimate of that process wastewater stream's benzene content (see Table 4-8). The average flow factors are simply multiplied by the corresponding process capacities to calculate the rate of wastewater production for each process. These wastewater production rates are multiplied by the average benzene concentration for each stream to calculate the loading rate of benzene into the wastewater system by process. These process wastewater loading rates were summed to calculate the total loading rate of benzene into the wastewater system. This total loading rate was multiplied by 0.85 (fraction emitted) to calculate the "uncontrolled" emission rate. (Benzene loadings from methyl ethyl ketone (MEK) dewaxing units were several orders of magnitude less than those from other processes so that no error was introduced in not using the 0.49 emission factor suggested for that process (see Table 4-8).)

Table 4-8. Model Process Unit Characteristics for Petroleum Refinery Wastewater

Process Unit	Average Flow Factor[a] (gal/bbl)[b]	Average Benzene Concentration[c] (ppmw)[d]	Origin of Benzene Concentration[e]	Fraction Emitted[f]
Crude distillation	2.9	21	114	0.85
Alkylation unit	6	3	Eq.	0.85
Catalytic reforming	1.5	106	Eq.	0.85
Hydrocracking unit	2.6	14	114	0.85
Hydrotreating/hydrorefining	2.6	6.3	114	0.85
Catalytic cracking	2.4	13	114	0.85
Thermal cracking/coking	5.9	40	Eq.	0.85
Thermal cracking/visbreaking	7.1	40	Eq.	0.85
Hydrogen plant	80[g]	62	90-day	0.85
Asphalt plant	8.6	40	Eq.	0.85
Product blending	2.9	24	114	0.85
Sulfur plant	9.7[h]	0.8	90-day	0.85
Vacuum distillation	3	12	90-day	0.85
Full range distillation	4.5	12	114	0.85
Isomerization	1.5	33	Eq.	0.85
Polymerization	3.5	0.01	90-day	0.85
MEK dewaxing units	0.011	0.1	90-day	0.49[i]
Lube oil/specialty processing unit	2.5	40	Eq.	0.85
Tank drawdown	0.02	188	90-day	0.85

Source: U.S. EPA (1998a)

[a] All flow factors were derived from Section 114 questionnaire responses

[b] gal/bbl = gallons of wastewater per barrel of capacity at a given process unit

[c] Average concentration in the wastewater

[d] ppmw = parts per million by weight

[e] 114 = Section 114 questionnaire response; 90-day = 90-day BWON report; Eq. = equilibrium calculation; and Ratio = HAP-to-benzene ratio (4.48)

[f] These factors are given in lbs HAP emitted/lbs HAP mass loading

[g] This flow factor is given in gal/MM ft^3 of gas production

[h] This flow factor is given in gal/ton of sulfur

[i] Fraction emitted as reported in U.S. EPA (1998a); for computational ease, the REM uses a fraction emitted of 0.85 for all sources.

For some processes, the average flow factors and average wastewater benzene concentrations had to be estimated (e.g., aromatics and oxygenates); for other activities, the process throughput had to be estimated in order to use the given flow factors (e.g., product blending and tank draw down). The assumptions used to make these estimates are outlined below:

- The benzene wastewater loading rate for aromatics was estimated using an average flow factor of 3 (because a wide variety of processes had production rates between 2.5 and 3) and a benzene wastewater concentration based on the value for CRUs (the highest benzene content of all process wastewater streams except tank drawdown).

- The benzene wastewater loading rate for oxygenates was estimated using the average flow factor and average benzene concentration value for full-range distillation.

- The benzene wastewater loading rate for coke plants was estimated using the average flow factor and average benzene concentration value for SRU.

- The product blending and tank drawdown throughputs were estimated as the larger of either

  – The crude capacity / 12, or
  – (CCU capacity) / 4 + (oxygenates production) / 4 + (CRU capacity) / 8 .

- The MEK dewaxing throughput was estimated as the lube oil production rate.

More than 30 percent of the total benzene loading is produced from crude distillation. Thermal cracking and catalytic reforming are responsible for another 32 percent of the total benzene load to wastewater. Vacuum distillation, catalytic cracking, hydrotreating, aromatics, asphalt production, and product blending each contribute between 4 and 8 percent of the total benzene loading. All other processes contribute roughly 1 percent or less to the total benzene loading. Therefore, most of the assumptions outlined above have little impact on the total benzene loading rate to the wastewater treatment system.

The benzene loading and emission estimates following this procedure are expected to represent uncontrolled or pre-BWON emissions. The uncontrolled emissions were compared to 90-day reports prior to the implementation of the BWON. The range of refinery emissions and the total nationwide emissions for benzene from wastewater using the methodology described above compared well with the pre-BWON benzene emissions. Review of 90-day reports after implementation of the BWON and a review of the emissions reported by the Louisiana refineries suggest that refineries subject to the BWON have wastewater benzene emissions of between 5 and 10 tons per year (tpy). Therefore, a hypothetical correlation was developed to calculate the benzene emissions from wastewater after implementation of the BWON.

If a refinery's total benzene loading rate was 10 tpy or less, then the "uncontrolled" emissions rate (i.e., 85 percent of benzene loading rate) was output for that refinery directly. If a refinery's total benzene loading rate exceeded 10 tpy, then the "uncontrolled" emissions rate was adjusted as follows to calculate a controlled emission rate after implementation of the BWON:

$$EmBz_{post\text{-}BWON} = \frac{EmBz_{pre\text{-}BWON}}{20} + 4.5 \qquad \textbf{4-3}$$

where

$EmBz_{post\text{-}BWON}$ = benzene wastewater emissions after implementation of BWON (tpy)
$EmBz_{pre\text{-}BWON}$ = benzene wastewater emissions calculated using the Benzene L&E method (tpy)

Once the benzene emission rates were estimated, these emission rates were used to project the emissions of other compounds. The average concentration of liquid refinery streams as developed for the refinery MACT I (Murphy, 1993) was used as a starting point for these projections (see Table 4-9). To account for the various compounds' affinity for water, the average concentrations were divided by the octanol-water partition coefficient to estimate "equilibrium" wastewater concentrations. These equilibrium wastewater concentrations were normalized by the calculated equilibrium wastewater concentration for benzene to develop a wastewater concentration ratio (also provided in Table 4-9).

Table 4-9. Development of Wastewater Treatment Emission Multipliers

CASRN	HAP	Average Concentration[a] (wt%)	Log (K_{ow})[b]	Wastewater Concentration Ratio	HLC[b]	Ratio to Benzene Wastewater Emission Factor[c]	Wastewater Treatment Emission Multiplier
540-84-1	2,2,4-Trimethylpentane	8.51	4.09	0.057957	3.04	1.15	0.0667
71-43-2	Benzene	1.61	2.13	1	0.00558	1	1
92-52-4	Biphenyl	0.02	3.98	0.000175	0.000308	0.8	0.000140
1319-77-3	Cresols	0.23	1.95	0.216223	1.62E-06	0.05	0.0108
98-82-8	Cumene	0.57	3.58	0.012562	1.16	1.15	0.0144
100-41-4	Ethylbenzene	1.41	3.14	0.085584	0.00788	1	0.0856
110-54-3	Hexane	4.85	4	0.040636	0.0143	1.15	0.0467

(continued)

Table 4-9. (continued)

CASRN	HAP	Average Concentration[a] (wt%)	Log (K_{ow})[b]	Wastewater Concentration Ratio	HLC[b]	Ratio to Benzene Wastewater Emission Factor[c]	Wastewater Treatment Emission Multiplier
1634-04-4	Methyl tertiary butyl ether	0.71	1.901	0.747192	0.000555	0.8	0.5978
91-20-3	Naphthalene	0.37	3.36	0.013532	0.000483	0.8	0.0108
108-93-0	Phenol	0.09	1.48	0.249699	3.97E-07	0.05	0.0125
100-42-5	Styrene	0.72	2.94	0.069264	0.00275	1	0.0693
108-88-3	Toluene	5.64	2.75	0.840337	0.00664	1	0.8403
1330-20-7	Xylene	5.58	3.17	0.316088	0.00604	1	0.3161

[a] Average concentration of all refinery liquid streams as reported by Murphy (1993)
[b] Physical properties for chemicals as contained in CHEMDAT8 (U.S. EPA, 1994)
[c] Representative ratio of emission fractions for compound to that for benzene based on CHEMDAT8 model runs for two select aerated tanks

Not only do the different chemicals have a different affinity for water, they also have a different affinity for volatilization from wastewater, as seen by the different values for their Henry's law constant (HLC). Two different wastewater treatment systems (one with high biological activity and one with low biological activity) were developed and projected 85 percent emissions for benzene using the CHEMDAT8 model for aerated tanks (U.S. EPA, 1994). The emission fraction for the other compounds was calculated and compared to the emission fraction for benzene. Based on these evaluations, an emission ratio (relative to benzene) was established. By combining the concentration ratio and the emission ratio, a multiplying factor was developed to project the emissions of other compounds based on the estimated emissions of benzene (see Table 4-9).

4.3.2 Source Characteristics

The wastewater treatment in the petroleum refinery industry is typically effected by biological treatment in activated sludge systems. These systems generally operate a series of open tanks such that the wastewater treatment system is best characterized as a large area source. Some refineries may employ a steam stripper to remove benzene and other VOCs prior to other wastewater treatment operations; for these refineries, a portion of the total benzene emissions would originate from a stack.

Previous emission modeling of wastewater collection and treatment suggests that a large portion of the emissions from wastewater occur in the collection phase. These collection areas are located within the process equipment area, whereas the wastewater treatment plant is generally a distinct portion of the refinery. The collection area emissions are again essentially all area source emissions. For this application, half of the estimated wastewater emissions were

assumed to occur from areas within the process equipment and half from the actual wastewater treatment plant area.

The area of the wastewater treatment plant was estimated based on three model refinery plot plans developed by EPA (U.S. EPA, 1978). The model refinery plot plans were also used to estimate the area of the wastewater collection system within the process area of the plant based on oil-water separators located within the equipment area. From this analysis, three model wastewater treatment areas were established. The collection areas estimated were very similar to the wastewater treatment plant area, so the wastewater treatment areas were used for both the wastewater and the collection areas. Table 4-10 provides the model wastewater treatment areas and the refinery crude capacity ranges used to assign the model areas to each refinery.

Table 4-10. Model Plant Areas for Wastewater Collection and Treatment

Model Unit Crude Capacity	Model Unit Applied to Refineries with Crude Capacity in Range	Wastewater Collection Area (MM ft^2)	Wastewater Treatment Area (MM ft^2)
50,000	0 to <125,000	0.34	0.34
200,000	125,000 to <225,000	1.0	1.0
250,000	≥225,000	2.0	2.0

4.3.3 Uncertainty in Estimates

Many assumptions were used to develop the emission estimates from wastewater. The L&E methodology appeared to provide only "uncontrolled" emission estimates for benzene, and a simple correlation was used to reduce the refinery's benzene emissions to between 5 and 10 tpy (depending on its uncontrolled emissions) if the facility was anticipated to be subject to the BWON. Finally, the benzene emissions were used to project the emission of other compounds using theoretical partitioning considerations. Given these assumptions, it is difficult to assess the uncertainties in the model without a comparison of the model results with those reported or measured at selected refineries.

Table 4-11 provides a comparison of emissions of benzene, toluene, and hexane calculated from the model with those reported for nine Louisiana refineries in their Title V applications. The emissions for benzene reflect inaccuracies in the L&E method and the BWON correction correlation. The emissions for toluene and hexane provide insight into the uncertainty of the combined methodology for nonbenzene compounds. Of the 13 compounds for which wastewater emissions are projected, benzene has the highest emission potential (as indicated by the multiplication factor) and the highest unit risk factor. Therefore, the benzene emissions will drive the risk from wastewater. Except for the one very low benzene emission rate reported by

Table 4-11. Comparison of Wastewater Emission Model Estimates and Reported Wastewater Emissions

Refinery	Crude Capacity (bbl/cd)	Emissions (tons/yr)					
		Benzene		Toluene		Hexane	
		Data[a]	Model[b]	Data[a]	Model[b]	Data[a]	Model[b]
Exxon, Baton Rouge	485,000	14.1	10.6	15.3	8.9	1.7	0.50
Citgo, Lake Charles	300,000	4.4	9.2	3.2	7.7	1.2	0.43
BP, Belle Chase	250,000	9.5	7.4	8.6	6.2	0.05	0.35
Marathon, Garyville	232,000	3.6	7.7	2.7	6.5	0.61	0.36
Shell, Norco	220,000	NR	7.0	NR	5.9	NR	0.33
Exxon, Chalmette	183,000	15.8[c]	7.1	27.9[c]	6.0	5.4[c]	0.33
Murphy, Meraux	95,000	0.41	5.3	0.26	4.5	3.4	0.25
Valero, Krotz Springs	78,000	9.8	5.1	4.2	4.3	0.80	0.24
Pennzoil, Shreveport	46,000	3.1	5.0	6.7	4.2	1.8	0.23

NR = not reported

[a] Data reported in the Title V permit applications for selected Louisiana refineries

[b] Predicted wastewater treatment emission estimates from the emissions model algorithm

[c] Includes emissions from fugitive equipment leaks; model estimates for benzene from fugitives and wastewater treatment are 17.4 tons/yr

Murphy Oil, the modeled benzene emissions are within a factor of 2 of the reported benzene wastewater emissions. The emission estimates of toluene also appear to be within a factor of 2, but toluene partitioning and volatility are reasonably similar to those for benzene. The reported emissions for hexane confirm that hexane wastewater emissions are significantly lower than those for benzene, but perhaps not to the extent predicted by the model. These lower hexane wastewater emissions can only be attributed to its lower affinity for water (hexane has higher concentrations in process streams and is more volatile from wastewater than benzene), so the oil-water partitioning is important. Based on this comparison, the REM nonbenzene wastewater emission estimates are likely accurate to within a factor of 5, whereas the benzene wastewater emissions, which drive the wastewater risk, are accurate to within a factor of 2.

There is also uncertainty in the precise split of emissions between the collection system (area within the process equipment) and the physical wastewater treatment plant. The 50:50 split is a rough approximation based on engineering judgment and experience with wastewater emission model results that consider the collection system components in series with the wastewater treatment tanks. Based on this experience, the total wastewater emission result is expected to have more uncertainty than is associated with the 50:50 split assumption. Therefore, the model emission estimate for the collection system for benzene is considered to be accurate to within a factor of 2, and the emission estimate for the wastewater treatment system is considered to be accurate within a factor of 2.

4.4 Cooling Towers

Cooling water is used in refineries in heat exchangers and condensers to cool or condense various product streams. The cooling water is usually sent to cooling towers where it is cooled to ambient temperature, then recycled to the process or to refrigeration units for additional cooling before reuse.

4.4.1 Emission Estimation Methodology

VOCs are picked up by cooling water when leaks occur in heat exchangers or condensers. Product on the high-pressure side leaks through the exchanger and contaminates the water. VOCs are then stripped from the water and emitted in the cooling tower. Emissions on the order of tons per year can occur for even low levels of contamination because refineries use large volumes of cooling water. For example, a refinery with 100,000 bbl/day of crude oil capacity typically uses about 170 MMgal/day cooling water (from AP-42 (U.S. EPA, 1995a), the cooling water rate is about 40 times the crude oil capacity). If this water is contaminated with easily strippable hydrocarbons at 1 ppm, the emission potential is 260 tpy.

The emission estimating methodology for cooling towers is given in AP-42 (U.S. EPA, 1995a; Section 5.1). For this assessment, the uncontrolled emission factor of 6 lb of total hydrocarbons (THC) per million gallons of water (MM gal) was used (a concentration in the water of 0.7 ppm). The controlled emission factor, based on monitoring for hydrocarbons and fixing leaks when they occur, is 0.7 lb/MM gal, a reduction of 88 percent. For petroleum refineries, the AP-42 section recommends a cooling water rate of 40 times the crude oil capacity. In terms of crude oil capacity, the emission factor for THC translates to 0.0018 tpy THC per bbl/day crude oil capacity.

Site-specific information on the composition of process streams cooled in heat exchangers and condensers is not currently available. However, an average composition of all process streams at a refinery was developed to estimate emissions for the Petroleum Refinery MACT I (40 CFR Part 63, Subpart CC). This average composition was used to speciate the THC and to generate the HAP emission factors given in Table 4-12.

An example calculation is given below for benzene from cooling towers at a refinery with a capacity of 100,000 bbl/day of crude oil:

$$\text{Benzene (tpy)} = 100{,}000 \text{ bbl/day} \times 3\text{E-}5 \text{ tpy/bbl/day} = 3 \text{ tpy.}$$

4.4.2 Source Characteristics

To develop source characteristics, the EPA document, “Development of Petroleum Refinery Plot Plans,” was reviewed (U.S. EPA, 1978). For a refinery of 200,000 bbl/day crude oil capacity, the document suggests a total of five cooling towers with a total flow rate of 8 MM bbl/day and a total cross-sectional area of 46,737 ft^2. The total cross-sectional area of all cooling towers is expected to be a function of refinery size (i.e., larger refineries have more or larger

Table 4-12. Emission Factors for Cooling Towers

HAP	Average Percentage in Process Liquids	Emission Factor (tpy per bbl/day)
2,2,4-Trimethylpentane	8.51	1.6E-04
Benzene	1.61	3.0E-05
Biphenyl	0.02	3.7E-07
Cresols	0.23	4.2E-06
Cumene	0.57	1.0E-05
Ethylbenzene	1.41	2.6E-05
Hexane	4.85	8.9E-05
Methyl-t-butyl ether	0.71	1.3E-05
Naphthalene	0.37	6.8E-06
Phenol	0.09	1.7E-06
Styrene	0.72	1.3E-05
Toluene	5.64	1.0E-04
Xylene	5.58	1.0E-04

cooling towers). For this analysis, the total cross-sectional area of cooling towers at each refinery was estimated from 0.2 ft^2 per bbl/day crude oil capacity based on the refinery described above.

The height for cooling towers at the 200,000 bbl/day refinery ranged from 20 ft to 30 ft. For comparison, the default height assigned in the 1996 NTI database was 32 ft. For this assessment, a default height of 30 ft was used. The only readily available information on exit velocity was the default value in the NTI – 11 ft/s.

4.4.3 Uncertainty in Estimates

There is a great deal of uncertainty in the emission estimates for cooling towers because of the scarcity of data. Emissions will depend on many site-specific features for which we have few data, such as the composition of products streams and water usage rates or measured contamination rates in cooling towers. If a given refinery has a program in place to detect leaks into cooling tower water and take corrective actions when necessary, the emission estimates may be somewhat conservative (high). We also have few data on the source characteristics of cooling towers, and these features likely vary from refinery to refinery. To reduce or quantify the uncertainty associated with these estimates for cooling towers, much more detailed, site-specific information is needed.

The permit applications for five of the Louisiana refineries contained emission estimates for cooling towers. Two of the refineries stated they used the controlled emission factor from

AP-42, and the others also appear to be based on the controlled emission factor. The estimates they provided for benzene ranged from 0.2 to 1.2 tpy. For comparison, the approach described earlier would estimate a range of 1.5 to 15 tpy for uncontrolled emissions for refineries of similar size. This comparison suggests that if most refineries actually have a leak detection and repair program in place to reduce cooling water contamination, then the estimates derived in this section are high (perhaps by a factor of 10) because the emissions are assumed to be uncontrolled. Based on the uncontrolled emission factors employed, cooling towers contribute roughly 20 percent of the refineries' benzene emissions. For certain chemicals, such as 2,2,4-Trimethylpentune, the contribution of uncontrolled cooling tower emissions can approach 50 percent of the refineries' total 2,2,4-Trimethylpentane emissions.

4.5 Fugitive Equipment Leaks

Equipment leaks are small point or area sources that occur throughout the process area of the refinery. Because of the large number of potentially leaking equipment components for any given process, let alone the entire refinery, fugitive equipment leaks are most appropriately modeled as a large area source. Leaking equipment may directly release gas or liquid; it is generally assumed that all released liquid eventually evaporates so that 100 percent of equipment leaks contribute to refinery emissions.

4.5.1 Emission Estimation Methodology

The fugitive equipment leak emissions were estimated using the revised equipment leak protocol developed for the petroleum refinery industry (U.S. EPA, 1995b) and model refinery equipment component counts and process streams composition data for benzene presented in EPA's L&E document (U.S. EPA, 1998a). The total fugitive equipment leak emissions calculated for benzene were then used to estimate the emissions for other HAPs using the average liquid stream compositions for refinery streams developed for the refinery MACT I standard (Murphy, 1993).

Table 4-13 presents the equipment leak rates for the revised refinery protocol (U.S. EPA, 1995b). These leak rates are used with equipment component counts and process stream concentrations to estimate emissions according to Equation 4-4:

$$EmR_{Bz} = EqLR_{C,level} \times N_{C,level} \times BzConc_{C} \qquad 4\text{-}4$$

where

EmR_{Bz} = the emission rate of benzene (kg/hr)

$EqLR_{C,level}$ = the equipment leak rate from Table 4-13 for the specified organic concentration measured by the monitoring device for that component (kg/hr/source)

$N_{C,level}$ = number of components at the $EqLR_{C,level}$ based on monitoring measurements

$BzConc_C$ = benzene process stream concentration for the component in service (weight fraction).

Table 4-13. Fugitive Equipment Leak Rate for Refinery Equipment Components[a]

Equipment Type (All Services)	Default Zero Emission Rate (kg/hr/source)	Pegged Emission Rates (kg/hr/source)		Correlation Equation[b] (kg/hr/source)
		10,000 ppmv	100,000 ppmv	
Valve	7.8E-06	0.064	0.140	$2.29E\text{-}06 \times SV^{0.746}$
Pump	2.4E-05	0.074	0.160	$5.03E\text{-}05 \times SV^{0.610}$
Other[c]	4.0E-06	0.073	0.110	$1.36E\text{-}05 \times SV^{0.589}$
Connector	7.5E-06	0.028	0.030	$1.53E\text{-}06 \times SV^{0.735}$
Flange	3.1E-07	0.085	0.084	$4.61E\text{-}06 \times SV^{0.703}$
Open-Ended Line	2.0E-06	0.030	0.079	$2.20E\text{-}06 \times SV^{0.704}$

[a] As reported in U.S. EPA (1995b)

[b] SV is the screening value (SV, ppmv) measured by the monitoring device

[c] The "other" equipment type was developed from instruments, loading arms, pressure relief devices, stuffing boxes, vents, compressors, dump lever arms, diaphrams, drains, hatches, meters, and polished rods. This "other" equipment type should be applied to any equipment other than connectors, flanges, open-ended lines, pumps, or valves

The median equipment component counts for "small" refineries (less than 50,000 bbl/cd) and "large" refineries (greater than 50,000 bbl/cd) as presented in the Benzene L&E document (U.S. EPA, 1998a) are presented in Tables 4-14 and 4-15, respectively. The Benzene L&E document also presents average process stream benzene concentrations based on the stream type or "service" (i.e., if the process stream is a gas, a light liquid, or a heavy liquid). These data are presented in Table 4-16.

Given these data, the equipment leak emissions for benzene can be calculated for each process in the model refineries once the number of leaking components is determined. For the preliminary analysis, it was assumed that 97 percent of the components were not leaking (i.e., used the default zero leak rate), 2 percent were leaking at the 10,000 ppmv pegged emission rate, and 1 percent were leaking at the 100,000 ppmv pegged emission rate. There is some disparity between the leak rates reported by refineries and those observed by EPA. For 17 refineries investigated by the EPA, the average leak rate reported by the facilities was 1.3 percent, whereas the average leak rate determined by EPA (and confirmed by the facilities) was 5 percent (U.S. EPA, 1999). The assumed 3 percent leak rate is a midrange value between these two reported values.

Table 4-14. Median Equipment Leak Component Counts for Small Model Processes[a]

Process Unit	Valves			Pumps		Com-pres-sors	Pressure Relief Valves			Flanges			Open-Ended Lines	Sampling Connec-tions
	Gas	Light Liquid	Heavy Liquid	Light Liquid	Heavy Liquid		Gas	Light Liquid	Heavy Liquid	Gas	Light Liquid	Heavy Liquid		
Crude Distillation	75	251	216	8	8	2	6	6	5	164	555	454	39	10
Alkylation (sulfuric acid)	278	582	34	18	10	1	12	15	4	705	1296	785	20	16
Alkylation (HF)	102	402	62	13	3	2	12	13	0	300	1200	468	26	8
Catalytic Reforming	138	234	293	8	5	3	5	3	3	345	566	732	27	6
Hydrocracking	300	375	306	12	9	2	9	4	4	1038	892	623	25	10
Hydrotreating/Hydrorefining	100	208	218	5	5	2	5	3	5	290	456	538	20	6
Catalytic Cracking	186	375	450	13	14	2	8	8	7	490	943	938	8	8
Thermal Cracking (visbreaking)	206	197	0	7	0	0	4	0	0	515	405	0	0	4
Thermal Cracking (coking)	148	174	277	9	8	2	7	16	13	260	322	459	13	8
Hydrogen Plant	168	41	0	3	0	2	4	2	0	304	78	0	8	4
Asphalt Plant	120	334	250	5	8	2	5	10	9	187	476	900	16	6
Product Blending	67	205	202	6	11	1	10	6	22	230	398	341	33	14
Sulfur Plant	58	96	127	6	6	3	3	88	15	165	240	345	50	3
Vacuum Distillation	54	26	84	6	6	2	2	5	2	105	121	230	16	4
Full-Range Distillation	157	313	118	7	4	2	5	4	6	171	481	210	20	6
Isomerization	270	352	64	9	2	2	7	10	1	432	971	243	7	8
Polymerization	224	563	15	12	0	1	10	5	3	150	450	27	5	7
MEK Dewaxing	145	1208	200	35	39	3	10	14	4	452	1486	2645	19	17
Other Lube Oil Processes	153	242	201	7	5	2	5	5	5	167	307	249	60	6

[a] Process component counts as presented in the Benzene L&E document (U.S. EPA, 1998a) for refineries with crude capacities less than 50,000 bbl/cd

Table 4-15. Median Equipment Leak Component Counts for Large Model Processes[a]

Process Unit	Valves			Pumps		Com-pres-sors	Pressure Relief Valves			Flanges			Open-Ended Lines	Sampling Connec-tions
	Gas	Light Liquid	Heavy Liquid	Light Liquid	Heavy Liquid		Gas	Light Liquid	Heavy Liquid	Gas	Light Liquid	Heavy Liquid		
Crude Distillation	204	440	498	15	14	2	7	5	12	549	982	1046	75	9
Alkylation (sulfuric acid)	192	597	0	21	0	2	13	4	0	491	1328	600	35	6
Alkylation (HF)	104	624	128	13	8	1	9	11	1	330	1300	180	40	14
Catalytic Reforming	310	383	84	12	2	3	8	11	0	653	842	132	48	9
Hydrocracking	290	651	308	22	12	2	10	12	0	418	1361	507	329	28
Hydrotreating/Hydrorefining	224	253	200	7	6	2	9	4	8	439	581	481	49	8
Catalytic Cracking	277	282	445	12	12	2	11	9	13	593	747	890	59	15
Thermal Cracking (visbreaking)	110	246	130	7	6	1	6	3	15	277	563	468	30	7
Thermal Cracking (coking)	190	309	250	12	11	1	8	5	10	627	748	791	100	10
Hydrogen Plant	301	58	0	7	360	3	4	139	0	162	148	0	59	21
Asphalt Plant	76	43	0	4	0	0	3	7	0	90	90	0	24	24
Product Blending	75	419	186	10	10	2	9	16	6	227	664	473	24	8
Sulfur Plant	100	125	110	8	3	1	4	4	4	280	460	179	22	7
Vacuum Distillation	229	108	447	2	12	1	5	1	4	473	136	1072	0	7
Full-Range Distillation	160	561	73	14	2	2	7	8	2	562	1386	288	54	6
Isomerization	164	300	78	9	5	2	15	5	2	300	540	265	36	7
Polymerization	129	351	82	6	2	0	7	12	28	404	575	170	17	9
MEK Dewaxing	419	1075	130	29	10	4	33	6	18	1676	3870	468	0	7
Other Lube Oil Processes	109	188	375	5	16	3	8	6	20	180	187	1260	18	9

[a] Process component counts as presented in the Benzene L&E document (U.S. EPA, 1998a) for refineries with crude capacities greater than 50,000 bbl/cd

Table 4-16. Concentration of Benzene in Refinery Process Unit Streams[a]

Process Unit	Weight % Benzene in Stream Type:		
	Gas	Light	Heavy Liquid
Crude	1.3	1.21	0.67
Alkylation (sulfuric acid)	0.1	0.23	0.23
Catalytic Reforming	2.93	2.87	1.67
Hydrocracking	0.78	1.09	0.1
Hydrotreating/Hydrorefining	1.34	1.38	0.37
Catalytic Cracking	0.39	0.71	0.2
Thermal Cracking (visbreaking)	0.77	1.45	1.45
Thermal Cracking (coking)	0.24	0.85	0.18
Product Blending	1.2	1.43	2.15
Full-Range Distillation	0.83	1.33	1.08
Vacuum Distillation	0.72	0.15	0.22
Isomerization	2.49	2.49	0.62
Polymerization	0.1	0.1	0.1
MEK Dewaxing	0.36	NR	NR
Other Lube Oil Processing	1.2	1.2	0.1

[a] Data reported in U.S. EPA (1998a)
NR - not reported

Some processes did not have any benzene concentration data. These processes were assumed to have benzene concentrations of 0.01 percent, except for asphalt. The benzene concentration in asphalt (all streams) was assumed to be 0.03 percent based on the weight percent of benzene in asphalt product as reported in the Benzene L&E document (U.S. EPA, 1998a).

Using the data from Tables 4-13 through 4-16 and the 97, 2, and 1 percent leak rate assumption, the benzene emissions could be calculated for each process in the model refineries. The results of these calculations are presented in Table 4-17. These emission rates were applied to each refinery on a process-specific basis. That is, if a refinery operates two CCUs, then the CCU equipment leaks were calculated for each CCU and summed together for that refinery. In order to do this, "small" and "large" processes needed to be defined. Using the relative U.S. capacities of crude and other processes as reported in the 2000 Worldwide Refining Survey (Stell, 2000a), average process-specific capacity limits were derived based on a refinery with a crude capacity of 50,000 bbl/cd. These process-specific capacities used to distinguish "small" and "large" processes are presented in Table 4-17. The "small" process emission rate was

applied when the refinery's process capacity was at or below the cutoff limit; "large" process emission rates were applied when the process capacity exceeded the cutoff limit. Using process-specific capacities provided a more facility-specific analysis based on the presence, number, and capacity of the individual processes at the refinery.

Table 4-17. Model Process Equipment Leak Emission Rates for Benzene

Process Unit	Size Cutoff (bbls/cd)	Benzene Emissions (tons/yr)	
		Small	Large
Crude Distillation	50,000	0.452	0.962
Vacuum Distillation	25,000	0.053	0.221
Thermal Cracking (coking)	10,000	0.174	0.339
Thermal Cracking (visbreaking)	10,000	0.362	0.604
Catalytic Cracking	17,500	0.377	0.349
Catalytic Reforming	10,000	1.386	1.726
Hydrocracking	5,000	0.641	0.776
Hydrotreating/Hydrorefining	35,000	0.441	0.593
Alkylation	5,000	0.159[a]	0.154[a]
Polymerization	1,000	0.037	0.045
Aromatics	5,000	1.386[b]	1.726[b]
Isomerization	2,500	1.332	0.904
Other Lube Oil Processes	5,000	0.292	0.255
Full-Range Distillation	5,000	0.436	0.914
Hydrogen Plant	10[c]	0.002	0.003
Coke	375[d]	0.003[e]	0.003[e]
Sulfur Plant	75[d]	0.003	0.003
Asphalt Plant	5,000	0.017	0.003
Product Blending	5,000	0.635	0.862
MEK Dewaxing	5,000	0.135	0.204

[a] Average of emission rates calculated for sulfuric acid alkylation and HF alkylation
[b] Component counts for aromatics unavailable; set equal to emission rate from CRU
[c] Production rate in MMcf/day
[d] Production rate in tonnes/day
[e] Component counts for coke were unavailable; set equal to emission rate from SRU

Once the total benzene equipment leaks emissions were calculated for a given refinery (based on the type, number, and size of process units), the total benzene emissions were multiplied by a concentration ratio to estimate the equipment leak emissions of other compounds. The concentration ratio was based on the average composition of all liquid waste streams as presented in a MACT I project memorandum (Murphy, 1993). The reported average concentrations and the calculated concentration ratio are presented in Table 4-18.

4.5.2 Source Characteristics

All fugitive process equipment leaks were characterized as one large area emission source originating from the process area. The process area was estimated based on model refinery plot plans developed by EPA (U.S. EPA, 1978). The three model plants and their respective process equipment areas are provided below in Table 4-19.

4.5.3 Uncertainty in Estimates

There are several sources of uncertainty in the REM equipment leak emission estimates, including the equipment component counts, the benzene stream composition, the equipment leak emission rates, the assumptions of leaking frequency, and the ratios used to translate benzene emissions to the emissions of other compounds. The uncertainty resulting from equipment component counts is one source of uncertainty but appears to be limited based on a comparison of the benzene emission factors developed for the two model plant/process sizes (most small and large benzene emission factors are within approximately 30 percent of each other, with a few varying by a factor of 2). Process benzene concentrations are also uncertain. Although the raw data used to develop the model stream composition were not available for review, average waste stream compositions for these processes probably do not vary by more than a factor of 2 between refineries. The largest uncertainties lie with the assumptions used regarding the equipment leak rates, the emission factor developed for aromatics units (where no equipment component counts or stream composition data were available, but where benzene concentration could potentially approach 100 weight percent), and the concentration ratios used to project the emissions of compounds other than benzene.

Based on the number of assumptions used to develop the emission estimates from equipment leaks, the equipment leak emission estimates could vary by a factor of 5 or more. To better understand the uncertainty in the process equipment leak emission estimates, a complete review of the data used to develop the component counts and process stream concentrations, as well as Method 21 data on equipment leaks (to better determine the range of percent leaking components), would be needed. By defining the range of values, a Monte Carlo or “boot strap” analysis could be performed to characterize the uncertainty in the final equipment leak emission factors. However, a comparison of the equipment leak emissions estimated for the nine Louisiana refineries for which Title V permit application data were available provides a simpler method of assessing the inaccuracies in the emission estimation methodology. Table 4-20 presents the reported equipment leak emissions with those calculated using the methodology described in this section. The REM equipment leak emission estimates for benzene agree better

Table 4-18. Concentration Ratios Used for Equipment Leak Emission Estimates

CASRN	HAP	Average Liquid Concentration[a] (wt%)	Concentration Ratio for Equipment Leaks[b]
540-84-1	2,2,4-Trimethylpentane	8.51	5.286
71-43-2	Benzene	1.61	1.000
92-52-4	Biphenyl	0.02	0.012
1319-77-3	Cresols	0.23	0.143
98-82-8	Cumene	0.57	0.354
100-41-4	Ethylbenzene	1.41	0.876
110-54-3	Hexane	4.85	3.012
1634-04-4	Methyl tertiary butyl ether	0.71	0.441
91-20-3	Naphthalene	0.37	0.230
108-93-0	Phenol	0.09	0.056
100-42-5	Styrene	0.72	0.447
108-88-3	Toluene	5.64	3.503
1330-20-7	Xylene	5.58	3.466

[a] Average composition of all liquid process streams as reported by Murphy (1993)
[b] Ratio of average liquid concentration of selected HAP to average liquid concentration for benzene

Table 4-19. Model Plant Areas for Fugitive Equipment Leaks

Model Unit Crude Capacity	Model Unit Applied to Refineries with Crude Capacity in Range	Equipment Leak Process Area (MM ft^2)
50,000	0 to <125,000	0.6
200,000	125,000 to <225,000	5.2
250,000	≥225,000	8

with reported emissions than the layers of uncertainty in the analysis suggest; many of the predicted emissions are within 30 percent of the reported values, and the largest discrepancies are roughly a factor of 2.

However, based on the comparison of refinery reported-equipment leak rates versus equipment leak rates determined by EPA (U.S. EPA, 1999), the equipmet leak rates reported by the refineries for which we have data may underestimate actual equipment leak emissions if they

are similarly underreported. The data in Table 4-20 also indicate that the emission estimates for HAPs other than benzene are more highly variable; the inaccuracies for these compounds generally vary between a factor of 2 and a factor of 5. This is somewhat expected because the benzene emissions used process-specific benzene concentrations, and the ratio of the HAP concentration to benzene will vary by process. It might be possible to improve the emission estimates for these other compounds if more process-specific compositional data were available. Nonetheless, because benzene is the compound with the highest risk factor of the compounds listed in Table 4-18, these additional data may not be critical to improving the overall risk analysis.

Table 4-20. Comparison of Fugitive Equipment Leak Model Estimates and Reported Equipment Leak Emissions

Refinery	Crude Capacity (bbl/cd)	Emissions (tons/yr)					
		Benzene		Toluene		Hexane	
		Data[a]	Model[b]	Data[a]	Model[b]	Data[a]	Model[b]
Exxon, Baton Rouge	485,000	12.9	7.6	48.6	26.4	25.4	22.7
Citgo, Lake Charles	300,000	13.2	13.7	10.1	47.9	5.8	41.2
BP, Belle Chase	250,000	9.3	6.9	14.7	24.3	10.1	20.9
Marathon, Garyville	232,000	2.0	5.8	4.1	20.2	4.9	17.4
Shell, Norco	220,000	9.6	8.6	17.3	30.2	8.8	26.0
Exxon, Chalmette	183,000	15.8[c]	10.3	27.9[c]	36.2	5.4[c]	31.2
Murphy, Meraux	95,000	9.0	4.9	4.8	17.1	17.3	14.7
Valero, Krotz Springs	78,000	5.1	5.3	12.2	19.3	46.4	16.6
Pennzoil, Shreveport	46,000	3.0	4.7	93.1	16.4	36.0	14.1

[a] Data reported in the Title V permit applications for selected Louisiana refineries
[b] Predicted fugitive equipment leak emission estimates from the emissions model algorithm
[c] Includes emissions from wastewater treatment; model estimates for benzene from fugitives and wastewater treatment are 17.4 tons/yr

4.6 Tanks

Tanks are used to store crude oil prior to refining, intermediates between refining processes, and refined product streams (e.g., gasoline, diesel fuel, fuel oil, etc.). Nearly all storage tanks in the petroleum refinery industry used to store liquid material have been converted to floating-roof tanks. As the fluid levels in the tank rise and fall, a thin film of the contained liquid may remain on the tank walls and evaporate. Because storage tanks in the petroleum industry are generally 30 to 40 feet in diameter, these tank emissions occur over a reasonably large surface area. Additionally, except for a few process storage tanks, the storage tanks are generally located together in what is referred to as the "tank farm." Consequently, the tank farm can be considered one large area source and all tank emissions are assumed to come from this area.

4.6.1 Emission Estimation Methodology

Emission factors for tanks were developed from the Title V permit data reported for the Louisiana refineries. Based on a preliminary review of the data, four "classes" of tanks were designated based on the differences in the emissions from these tanks and the availability of data to characterize and apply the resulting emission factors. The four classes are

- Crude storage tanks;
- Light and intermediate product tanks (e.g., gasoline, diesel, jet fuel, and fuel oil);
- Heavy product tanks (lube oil and asphalt); and
- Aromatic product tanks.

Emissions reported for intermediate process storage tanks were included with the light and intermediate product tank emission totals.

In order to develop and employ emission factors for storage tanks, the throughput of crude, light and intermediate products, heavy products, and aromatic products was needed. Crude capacity and aromatic production capacity were used to normalize crude and aromatic tank emissions. A few refineries report no crude capacity but have significant capacities for other processes. To estimate tank emissions, the crude capacity was estimated as the sum of the reported vacuum and coking capacities for refineries with no reported crude capacity. The heavy-product tank emissions were normalized by the sum of the lube oil and asphalt production capacities. Light and intermediate production capacities were estimated based on the crude capacity (as calculated for tanks) minus the heavy product and aromatic product capacities. This methodology was devised based on product production rates reported in a limited number of the Title V applications; the data reviewed are summarized in Table 4-21. Because the "lights" plus "heavies" were essentially equal to the crude processing rate (except for the anomalous lube production rate reported by Murphy Oil), the crude minus the "aromatics" and "heavies" was used to estimate light and intermediate production capacities. Aromatic tanks were treated separately because these tanks have a much higher emission rates based on the high HAP concentrations of the aromatic material stored.

Using the data reported in the 2000 Worldwide Refining Survey (Stell, 2000a), the crude capacities and production rates for each refinery were used to calculate the throughput rates for each tank class. These throughput rates were used in conjunction with the reported emissions data for tanks, to develop emission factors for the different types of tanks. The Louisiana refinery emissions data, as extracted from the Title V permit applications, are presented in Appendix A. The emissions factors were calculated for each tank class for each refinery reporting tank data; these emission factors, along with associated statistics, are provided in Table 4-22.

Although all nine Louisiana refineries had reported storage tank emissions in their Title V permit applications, only six of the refineries provided sufficient detail to divide or classify the reported emissions into the four "classes" of storage tanks needed for the emissions model. For

Table 4-21. Average Annual Production Rates Reported in Title V Permit Applications for Louisiana Refineries

Plant	City	Crude Oil (bbl/cd)	Production Rates (bbl/cd)				Product to Crude Ratios		Sum Ratios
			Gasoline	Diesel	Jet Fuel	Lube Stock/Oil	Lights[1]	Heavies[2]	
Pennzoil	Shreveport	50,000	21,923	8,416	8,263	16,767	0.772	0.335	1.107
Murphy Oil	Meraux	110,000	64,132	0	46,661	138,031	1.007	1.255	2.262
BP-Alliance[3]	Belle Chase	253,869	137,177	84,051	40,416	255	1.031	0.001	1.032
Citgo	Lake Charles	271,082	163,480	101,452	0	9,589	0.977	0.035	1.013

[1] The "lights" ratio is the sum of gasoline, diesel, and jet fuel production rates divided by the crude oil processing rate

[2] The "heavies" ratio is the lube stock/oil production rate divided by the crude oil processing rate

[3] Reported data for two different years; the average of the reported values was used

Table 4-22. Emission Factors for Storage Tanks[1]

CASRN	Tank Souce/ Chemical	Emission Factor (lbs/MMbbl)				No. Nonzero[3]
		Average[2]	Median[2]	Maximum	Minimum	
	Crude					
71-43-2	Benzene	**11.46**	2.80	40.60	0.76	6 of 6
108-88-3	Toluene	**12.01**	2.61	53.32	0.44	6 of 6
1330-20-7	Xylene	**2.23**	0.43	11.65	0	4 of 6
110-54-3	Hexane	**21.43**	24.50	40.83	0.66	6 of 6
100-41-4	Ethylbenzene	**0.44**	0.06	2.24	0	3 of 6
95-63-6	1,2,4 Trimethylbenzene	**0.78**	0.11	2.60	0	3 of 6
	Lights					
71-43-2	Benzene	**102.4**	99.8	207.8	25.7	6 of 6
108-88-3	Toluene	**170.7**	172.0	287.2	44.4	6 of 6
1330-20-7	Xylene	**124.5**	105.5	242.4	33.6	6 of 6
1634-04-4	Methyl tert-butyl ether	**108.2**	78.9	234.5	0	5 of 6
110-54-3	Hexane	**348.1**	196.5	811.4	13.8	6 of 6
91-20-3	Naphthalene	**5.64**	3.23	20.25	0	4 of 6
100-41-4	Ethylbenzene	**15.54**	7.45	33.15	6.67	6 of 6
95-63-6	1,2,4 Trimethylbenzene	**16.45**	5.80	67.40	0	4 of 6
92-52-4	Biphenyl	**0.32**	0.00	1.26	0	2 of 6
98-82-8	Cumene	**2.15**	1.04	8.26	0	3 of 6
106-99-0	1,3 Butadiene	**0.33**	0.00	1.65	0	2 of 6
78-93-3	Methyl ethyl ketone	**320**	0	1,917	0	1 of 6
67-56-1	Methanol	**3.76**	0.00	22.58	0	1 of 6
540-84-1	2,2,4-Trimethylpentane	**31.5**	0.00	123.3	0	2 of 6
91-57-6	2-Methylnaphthalene	**3.46**	0.00	20.76	0	1 of 6
120-12-7	Anthracene	**0.24**	0.00	1.46	0	1 of 6
218-01-9	Chrysene	**0.21**	0.00	1.27	0	1 of 6
86-73-7	Fluorene	**0.36**	0.00	2.19	0	1 of 6
85-01-8	Phenanthrene	**1.49**	0.00	8.92	0	1 of 6
129-00-0	Pyrene	**0.39**	0.00	2.37	0	1 of 6
1319-77-3	Cresol	**0.37**	0.00	2.22	0	1 of 6

(continued)

Table 4-22. (continued)

CASRN	Tank Souce/ Chemical	Emission Factor (lbs/MMbbl)				No. Nonzero[3]
		Average[2]	Median[2]	Maximum	Minimum	
	Heavies					
71-43-2	Benzene	**39.96**[4]	4.12	75.80	0	2 of 3
108-88-3	Toluene	**29.19**[4]	17.44	40.95	0	2 of 3
1330-20-7	Xylene	**25.58**[4]	14.97	36.20	0	2 of 3
110-54-3	Hexane	4.24	0.00	**12.71**	0	1 of 3
91-20-3	Naphthalene	2.66	2.20	**5.77**	0	2 of 3
100-41-4	Ethylbenzene	2.81	3.16	**5.29**	0	2 of 3
95-63-6	1,2,4 Trimethylbenzene	1.96	0.00	**5.89**	0	1 of 3
92-52-4	Biphenyl	0.23	0.00	**0.69**	0	1 of 3
98-82-8	Cumene	0.14	0.00	**0.41**	0	1 of 3
	PNA/PAH	5.77	0.00	**17.30**	0	1 of 3
	Aromatics					
71-43-2	Benzene	**2,864**	526	8,067	0	2 of 3
108-88-3	Toluene	**6,630**	-	19,890	0	1 of 3
1330-20-7	Xylene	**4,827**	80	14,400	0	2 of 3
100-41-4	Ethylbenzene	**957**	-	2,871	0	1 of 3
95-63-6	1,2,4 Trimethylbenzene	**66**	-	197	0	1 of 3

[1] Emission factors used in the model are bolded
[2] Average and medians include zero values unless otherwise noted
[3] Number of refineries reporting nonzero emissions of number of refineries reporting emissions for a given tank class
[4] Average based on the two nonzero emission factors

crude and light-product tanks, six refineries reported data for most of the more volatile organic chemicals; only one refinery reported any semivolatile emissions from the light-product tanks. It is uncertain whether the semivolatile tank emissions from the one refinery were based on some standard emission factor, a site-specific emission estimate, or actual measurements. These emissions were reported for some "fixed-roof distillates" tanks. Based on the lack of semivolatile emissions from the other light-end tanks, it was decided to use the average emission factor, including the zero values for the other refineries.

For the heavy-product storage tanks, only two of the three refineries that had heavy production capacity (as calculated using the 2000 Worldwide Refining Survey data). A third refinery, Murphy Oil, had reported emissions of naphthalene and PAH/polynuclear aromatic hydrocarbons (PNAs) from "heavy oil" tanks. Although this refinery does not have "heavies

production," as calculated in the model, Murphy Oil had reported heavy production (albeit a questionably high value) in its Title V Permit application. Consequently, either the average or the maximum value reported for the two refineries projected to have "heavies" emissions was used; and only the emissions for PAH/PNAs reported by Murphy Oil were used to develop an emission factor. For this emission factor, "heavies production" was estimated as 1 percent of the crude capacity.

All three refineries expected to have aromatic production reported emissions from their aromatics product tanks. However, each of these refineries produced a different mix of aromatics. One refinery only produced benzene; one refinery produced benzene and xylene; and the third produced toluene and xylenes. The limited available data were assumed to be representative of the different mixes of product so that the emission factors developed included zeros for the refineries that did not make that product.

Given the emission factors presented in Table 4-22, the storage tank emissions can be calculated using the production capacity data reported in the 2000 Worldwide Refining Survey (Stell, 2000a) for each storage tank class. The emissions for each storage tank class were then summed to develop the total tank farm emissions.

4.6.2 Source Characteristics

The emissions from the storage tanks were modeled as one large area source representative of the total tank farm area. Model tank farm areas were estimated based on model refinery plot plans developed by EPA (U.S. EPA, 1978). The three model plants and their respective tank farm areas are provided below in Table 4-23.

Table 4-23. Model Plant Areas for Storage Tanks

Model Unit Crude Capacity	Model Unit Applied to Refineries with Crude Capacity in Range	Height (feet)	Tank Farm Area (MM ft^2)
50,000	0 to <125,000	40	4
200,000	125,000 to <225,000	40	13
250,000	≥225,000	40	34

4.6.3 Uncertainty in Estimates

Table 4-22 provides some measure of the uncertainty in the storage tank emissions. Based on a comparison of the average and median values for crude tanks, it appears that different crude stocks vary significantly in aromatic content, while the hexane content is fairly consistent (save one very low value). For nearly all refineries, the "lights" throughput capacity is essentially equal to the refinery's crude capacity, and benzene drives the risks for the organic HAPs emitted

from storage tanks. The emissions from light-product storage tanks are roughly an order of magnitude greater than the emissions from crude storage tanks. Therefore, because emissions are being modeled from the entire tank farm, the uncertainties in the crude storage tank emission factors are not of particular concern.

The central tendency indicators for VOCs from light-product storage tanks agree well, and these central tendency indicators are generally within a factor of 2 of the maximum value and a factor of 4 of the minimum value. Again, for most refineries and essentially all large refineries (i.e., those with catalytic cracking, reforming, or other refinery stream upgrade processes), the emissions from the light-product tanks will dwarf the emissions from crude and heavy-product storage.

There is a high level of uncertainty associated with the heavy-product storage tank emission factors, based on the limited number of data that were available for these tanks. Nonetheless heavy-product storage tank emissions will only make a very small contribution to tank farm emissions for most refineries. Only five refineries had heavy-production capacities of 30 percent of their crude capacity or more. All of these refineries have crude capacities of less than 12,000 bbl/cd. None of the Louisiana refineries for which Title V permit application data were available are very representative of these small, essentially "straight-run" refineries. Consequently, the emission factors selected from the limited data set were chosen using a more conservative high-end approach than was used for the other tank classes.

The uncertainty in the aromatics emissions is both large and significant. There are 30 refineries reporting aromatics production capacity. Based on the benzene emission factors for aromatics and light-product storage tanks, aromatics will contribute at least 25 percent of the tank farm's benzene emissions if aromatics production is only 1 percent of the "lights" production (true for 29 of the 30 refineries with aromatic production); they will contribute 50 percent or more of the tank farm's emissions if aromatics production is 3.5 percent or more of the lights production (true for 24 of the 30 refineries with aromatic production). The uncertainty in the emission factors for aromatic product storage tanks, as encountered in reviewing the limited data available for these tanks, is that the aromatics products may differ by refinery. The 2000 Worldwide Refining Survey (Stell, 2000a) provides some additional detail about the type of aromatic process employed, classifying the production capacities for the following aromatic units: BTX, hydrodealkylation (which produces benzene), cyclohexane, and cumene. This added level of detail regarding the aromatic units was not used for several reasons. First, no data were available to characterize cyclohexane and cumene product storage tank emissions. Moreover, all 30 refineries that had aromatics production capacity specified at least some production of BTX, and the BTX aromatics production capacity was 80 percent of the total aromatics production capacity. Thus, for the most significant aromatics production unit (BTX), which was listed for all refineries with aromatics production capacity, there was little option available other than to estimate emissions for all three aromatics (i.e., benzene, toluene, and xylene). Consequently, it is quite likely that for any given refinery, the REM estimates emissions of an aromatic product that the refinery does not have, and it is equally likely that the REM underestimates the emissions of the aromatic products that they do have. Although a slightly more refined analysis could be implemented that uses the additional information available about

the type of aromatic unit, this refined approach would also require additional emissions data to implement, and it would not alleviate the uncertainty for BTX units. Aromatic product storage tanks appear to be one area where a focused information collection effort could significantly improve the emission estimates and associated risk from storage tanks.

Table 4-24 provides a comparison of the overall tank farm emissions for benzene, toluene, and hexane as calculated by the model versus those reported in the Title V permit applications for the Louisiana refineries. The emissions are generally accurate within a factor of 2 to a factor of 5; the largest discrepancies stem from differences in aromatics production and the emissions reported by Shell, where three fixed-roof tanks are responsible for 60 to 70 percent of the reported benzene and toluene emissions. Most of the reported tank emissions are based on tank throughput capacity; the reported emissions may overstate actual emissions if the tanks are not used to capacity (e.g., if a refinery still has fixed-roof tanks, but rarely uses them).

4.7 Product Loading Operations

Product loading emissions occur when vapor is displaced by the liquid product when it is loaded into tank trucks, rail cars, and marine vessels. The vapor may contain constituents from the material previously transported and from the product being loaded.

Table 4-24. Comparison of Tank Farm Model Estimates and Reported Tank Emissions

Refinery	Crude Capacity (bbl/cd)	Emissions (tons/yr)					
		Benzene		Toluene		Hexane	
		Data[a]	Model[b]	Data[a]	Model[b]	Data[a]	Model[b]
Exxon, Baton Rouge	485,000	23.8[c]	9.9	67.8[c]	15.8	49.4[c]	31.7
Citgo, Lake Charles[d(B)]	300,000	21.2	9.7	14.4	17.9	46.3	20.3
BP, Belle Chase[d(BX)]	250,000	10.1	14.2	8.0	29.3	1.4	15.7
Marathon, Garyville	232,000	1.8	4.4	7.6	6.7	10.9	13.2
Shell, Norco	220,000	15.7	4.6	40.8	7.3	12.9	14.8
Exxon, Chalmette[d(TX)]	183,000	1.5	8.8	40.9	17.9	4.8	11.7
Murphy, Meraux	95,000	0.4	2.0	0.8	3.2	1.6	6.4
Valero, Krotz Springs	78,000	0.8	1.6	1.1	2.6	1.1	5.3
Pennzoil, Shreveport	46,000	1.5	0.9	2.5	1.3	5.7	2.6

NR = not reported

[a] Data reported in the Title V permit applications for selected Louisiana refineries

[b] Predicted tank farm emission estimates from the emissions model algorithm

[c] Includes "fugitive tank farm" emissions, which are roughly 25 percent of total tank farm emissions

[d] Refineries with aromatics production units; aromatics produced in parenthesis:
B= benzene, T=toluene, X=xylene(s)

4.7.1 Emission Estimation Methodology

A review of the permit applications for the nine Louisiana refineries for which we had data showed that eight reported marine vessel loading operations, and all of them captured emissions and vented them to a flare. Consequently, emissions from marine vessel loading are included in the emission factor for flares derived from these plants. For the ninth plant, which is the second smallest of the nine (crude capacity of 78,000 bbl/cd), loading emissions were reported separately and were not identified as from marine vessel loading.

Emissions from gasoline loading racks are regulated under MACT I for petroleum refineries (40 CFR Part 63, Subpart CC) and are limited to 10 mg of THC per liter of gasoline. For this analysis, a conservative assumption was made that all gasoline is loaded through these loading racks and that emissions occur at the allowable level (10 mg THC/L). The emission limit converts to 6.4E-4 tpy THC for each bbl/day of gasoline loaded.

Data were available for the estimated vapor-phase HAP composition of gasoline. The vapor-phase composition in Table 4-25 was multiplied by 6.4E-4 to generate the emission factors shown in the table in terms of tpy per bbl/day of material loaded. The "lights" production rate, as calculated for storage tanks (Section 4.6), was used to estimate the amount of material produced/loaded at each refinery. An example calculation is given below for benzene from loading emissions at a refinery producing 100,000 bbl/day of gasoline and other light distallate products:

Benzene (tpy) = 100,000 bbl/day × 6.1E-6 tpy per bbl/day = 0.6 tpy.

Table 4-25. Emission Factors for Loading

HAP	Average Weight Percentage in Vapor	Emission Factor (tpy per bbl/day)
2,2,4-Trimethylpentane	0.95	6.1E-06
Benzene	0.63	4.0E-06
Cumene	0.016	1.0E-07
Ethylbenzene	0.063	4.0E-07
Hexane	4.43	2.8E-05
Methyl-t-butyl ether	3.62	2.3E-05
Styrene	0.088	5.6E-07
Toluene	0.84	5.4E-06
Xylene	0.24	1.5E-06

For comparison, five of the Louisiana refineries reported benzene emissions from loading operations that were calculated from site-specific information—0.01, 0.05, 0.14, 0.22, and 0.51 tpy. The approach, based on an emission limit of 10 mg/L, appears to be conservative (high) relative to the estimates in permit applications.

4.7.2 Source Characteristics

Estimates of source characteristics were developed from review of the EPA document "Development of Petroleum Refinery Plot Plans" (U.S. EPA, 1978) and Title V permit applications. The model modules for plot plans described two sizes of truck loading racks, one that was 7 × 30.5 m (an area of 2,300 ft^2) and another that was 13.7 × 70.1 m (10,000 ft^2). Only one of the Louisiana facilities provided information on the truck loading area (5,000 ft^2). A midrange value of 5,000 ft^2 was chosen as the default value.

The model modules were assigned heights of 4.6 m (15 ft) and 6.1 m (20 ft). One of the Louisiana permit applications provided a height of 10 ft and a second was 15 ft. A midrange value of 15 ft was assigned as the default height.

4.7.3 Uncertainty in Estimates

Accurate estimates of loading emissions require site-specific data, such as the composition of the product, vapor pressures of the components, quantity loaded, loading procedure, and the effectiveness of the capture and control systems in place. This information was not available for this analysis. Consequently, the default approach used to estimate loading emissions may result in a great deal of uncertainty for a specific site. If we assume the estimates of loading emissions provided by five Louisiana refineries are based on site-specific information, comparisons can be made for benzene, which is a carcinogen of primary interest. The site-specific estimates for benzene ranged from 0.01 to 0.5 tpy for refineries with capacities of about 50,000 to 500,000 bbl/day. The default approach described earlier would estimate a range of benzene emissions of 0.3 to 3 tpy. This comparison suggests the default approach is conservative (high) with respect to estimating emissions from loading. However, loading emissions are not a significant contributor to the total facility emissions.

4.8 Catalytic Reforming Unit (CRU) Catalyst Regeneration Vents

The CRU is a series of catalytic reactors that turn naphtha into high-octane gasoline. There are no direct atmospheric vents from the naphtha reforming process, but the catalyst activity slowly diminishes with time and the catalyst must be regenerated. There are three basic types of CRU catalyst regeneration: continuous, cyclic, and semiregenerative. Continuous CRU catalyst regenerators operate continuously with a small slip stream of catalyst being recirculated between the CRU and the regenerator. Cyclic CRU essentially involves an extra CRU reactor. When regeneration is needed, one reactor is cycled offline and regenerated. The regeneration of the offline reactor is a batch process. When complete, the reactor is returned to service and the next reactor is cycled offline and regenerated. The process continues until all reactors are regenerated. In a cyclic CRU, regeneration may occur for 1,000 to 4,000 hours per year. The

semiregenerative CRU operates without regeneration for 8 to 18 months, then the entire unit is brought offline, and the entire unit is regenerated. The overall regeneration cycle typically takes 1 to 2 weeks.

During regeneration, there are several potential atmospheric vents. Although the location of the emission points might vary depending on whether catalyst regeneration is semiregenerative, cyclic, or continuous, emissions can occur regardless of the regenerator type at three times during the regeneration process. These three emission points are (1) the initial depressurization and purge vent; (2) the coke burn pressure control vent; and (3) the final catalyst purge vent.

The initial depressurization and purge cycle removes the hydrocarbons from the catalyst prior to CRU catalyst regeneration. The vent gases from this initial purge may have high levels of organic HAPs, such as BTX and hexane. This vent is typically vented to the refinery's fuel gas system or directly to a combustion device (e.g., flare or process heater). The coke burn cycle is typically the largest (in terms of gas volume) emission source of the overall catalyst regeneration cycle. The primary HAPs contained in the CRU coke burn vent are hydrogen chloride (HCl) and chlorine (Cl_2), which are produced when the water formed during combustion leaches chloride atoms from the CRU catalyst. The final purge and reduction cycle removes oxygen and any remaining chorination agent from the system and reduces the catalyst prior to returning CRU catalyst to the reforming process or bringing the unit back online. The vent gases from this final purge may have low levels of the chlorinating agent (usually an organic HAP, such as trichloroethene of perchloroethene) and residual HCl or Cl_2 remaining in the system. This vent is typically vented to the atmosphere or the refinery's fuel gas system, depending on the oxygen content of the vent gases (safety considerations restrict the venting of oxygen-containing gases to the fuel gas system).

The 2000 Worldwide Refining Survey data were supplemented with data available from the MACT II project database (Hansell, 1997). The additional data provided information on the number of CRUs at each refinery, the capacity for each CRU, and the type of control device used for the purge and coke-burn emission vents. Control device information was available for approximately 80 percent of the CRU based on capacity.

4.8.1 Emission Estimation Methodology

Few data are available to characterize the emissions from the CRU catalyst regeneration vent because venting is infrequent, the vent flow rates are slow and usually variable, and the vents have small diameters. All of these factors make traditional source testing difficult. Most of the available data are for HCl and Cl_2 emissions from "uncontrolled" coke burn (20 data available for HCl emissions; 10 data available for Cl_2). A few data were available for limited VOCs. These data are compiled in the background information document (BID) for the proposed MACT II rule (U.S. EPA, 1998b). During the MACT II project, the CARB, with funding assistance from EPA, conducted a source test of a continuous CRU catalyst regenerator coke burn vent for dioxins/furans, polychlorinated biphenyls (PCBs), and PAHs. The results from this source test, which were not yet available for inclusion into the MACT II BID, were used to

develop emission factors for these compounds. The emission factors used for the "uncontrolled" coke burn emissions are presented in Table 4-26. These emission factors are normalized by the CRU process throughput and were assumed to apply equally for all types of CRU regenerators.

Table 4-26. Emissions Factors for CRU Catalyst Regeneration Vent

CASRN	Chemical Name	Emission Factor (lb/1000 bbl)[a]
1746-01-6	Dioxin TEQ[b]	5.68E-09
1336-36-3	Total PCBs[c]	2.62E-06
91-20-3	Naphthalene	3.51E-05
91-57-6	2-Methylnaphthalene	1.29E-06
208-96-8	Acenaphthylene	3.03E-08
83-32-9	Acenaphthene	4.28E-08
86-73-7	Fluorene	1.95E-07
85-01-8	Phenanthrene	6.12E-07
120-12-7	Anthracene	9.14E-08
206-44-0	Fluoanthene	1.01E-07
129-00-0	Pyrene	1.51E-08
56-55-3	Benzo(a)anthracene	8.95E-10
218-01-9	Chrysene	2.87E-09
205-99-2	Benzo(b)fluoranthene	1.54E-09
207-08-9	Benzo(k)fluoranthene	7.48E-10
192-97-2	Benzo(e)pyrene	2.91E-09
193-39-5	Indeno(1,2,3-c,d)pyrene	1.74E-09
53-70-3	Dibenzo(a,h)anthracene	7.79E-10
191-24-2	Benzo(g,h,i)perylene	4.04E-09
71-43-2	Benzene	0.004
108-88-3	Toluene	0.0096
1330-20-7	Xylene	0.007
7647-01-0	HCl	4.225[d]
7782-50-5	Chlorine	0.225[d]

[a] Emission factor in lbs pollutant emitted per 1,000 bbl of CRU process capacity
[b] Dioxin TEQ = toxicity equivalence to 2,3,7,8-tetrachloro-dibenzo-p-dioxin used for risk analysis; specific dioxin/furan isomer emissions data are available
[c] Sum total of all chlorinated biphenyl emission factors; data available for each class of chlorinated biphenyls (mono-, di-, tri-, decachlorobiphenyl)
[d] Emission factor for "uncontrolled" coke burn vent; "controlled" emissions estimated based on minimum control device efficiencies

The most prevalent control device used in association with the coke burn vent is a wet scrubber. The dioxin/furan emissions source tests, as well as the volatile organics source tests were performed on a system controlled by a wet scrubber. Because of the limited solubilities of these chemicals and the scrubbing medium recirculation rate used for wet scrubbers on this vent stream, the scrubber is assumed to be ineffective at reducing the emissions of these chemicals. Therefore, the same emission factor was used for these chemicals for both controlled and uncontrolled CRUs. The scrubbers are expected to reduce the emissions of HCl and Cl_2. The scrubbers used for these vents were characterized into two classes: single-stage scrubbers and multiple-stage scrubbers. Single-stage scrubbers were estimated to reduce HCl and Cl_2 emissions by 92 percent, and the multiple-stage scrubbers were estimated to reduce HCl and Cl_2 emissions by 97 percent. For units with no control device information available, the emissions were estimated assuming 40 percent reduction efficiency (because control devices are used for just over 40 percent of the CRU capacity for which control device information is available).

Because most emissions from the purge cycles are vented to the RFG system or a flare, emissions from this source are not covered separately here; these emissions are presumably included in the RFG combustion sources (process heaters and boilers) or flares emissions estimates. No data are available to characterize the small portion of venting that occurs directly to the atmosphere from these purge cycles; no estimates of these emissions were included in the preliminary emissions estimates.

4.8.2 Source Characteristics

The CRU catalyst regeneration vent is generally a small-diameter (3 to 9 inch) stack or pipe. Except for the continuous CRU, the CRU catalyst regeneration vent only operates periodically throughout the year. Three model stacks were developed—one model stack for each type of CRU. The model stacks were developed based on information collected during site visits perfomed during the MACT II rulemaking, limited source test data for these vents, and limited data reported by the Louisiana refineries in their Title V applications. The model stack parameters are presented in Table 4-27.

Continuous CRU regenerators that did not have a wet scrubber to remove HCl generally had hooks at the end of the CRU so that rain would not fall into the system. Condensed water in the system would absorb HCl and corrode the pipes. Therefore, as indicated in Table 4-27, when no scrubber is present, the gas is vented at roughly 800°F. When a scrubber is used, the scrubbing medium (caustic water solution) cools the gas to approximately 150°F.

4.8.3 Uncertainty in Estimates

Based on the limited amount of data available to set the emission factors, there are large uncertainties in the emissions from the CRU vent for most chemicals, except perhaps for HCl and Cl_2. One other source test measuring dioxin/furans from a CRU has been performed; the dioxin TEQ emissions from this source test are roughly two orders of magnitude lower than the dioxin emission factors employed in the REM. The source test data used for the emission factors

Table 4-27. Model Stack Parameters for CRU Catalyst Regeneration Vent

CRU Type	Annual Operating Hours	Stack Height (ft)	Stack Diam. (ft)	Temp (°F)	Flow Rate (acfm)	Stack Velocity (ft/s)
Continuous	8,760	40	0.5	With WS: 150°F Without WS: 800°F	Calculated:	10
Cyclic	2,190	30	0.4		$\pi(\text{Diam}/2)^2 \times (\text{Vel}\times 60)$	25
Semiregenerative	120	20	0.33			70

in the REM were for a continuous CRU; this second test was performed on a semiregenerative CRU. Some differences in emissions are likely based on the CRU regenerator type. Continuous and cyclic CRUs process naphtha under more "severe" conditions than semiregenerative CRU because the frequency of regeneration does not have a significant impact on the process throughput for these units. Therefore, it is likely that these units may burn off more coke per bbl of CRU naphtha processed. The two orders-of-magnitude difference likely results from a combination of the differences in CRU regenerator type and the variability in the process emissions in general.

The "uncontrolled" emission factors associated with HCl and Cl_2 emissions were developed using a midrange estimate. As such, the emissions are generally within a factor of 2 of the highest measured emission factor, but can be an order of magnitude greater than the low-end value. The arithmetic average emission factor is roughly a factor of 2 less than the midrange value for HCl. As such, the lumped control factor applied to the emissions for units that did not report control device information still yields results that are generally characteristic of uncontrolled emissions. Very few emissions data are available for HCl from controlled CRUs; the few data available suggest that the control efficiencies for HCl wet scrubbers are generally higher than the control factors applied in the emission estimates. As such, the coke burn emission factors used in this analysis are considered to be biased high. This level of conservatism was considered appropriate because of the general lack of available data and lack of emission estimates for purge streams that are vented directly to the atmosphere.

There are also uncertainties in the stack parameters. This uncertainty arises from the limited amount of data available to characterize these sources. Particularly, uncertainties exist primarily in the stack height, flow rate/stack velocity, and operating hours (for noncontinuous CRUs). An example of this uncertainty is for a class of CRUs referred to as platformers. In platformers, the CRU reactors are positioned horizontally. These platformers are generally continuous CRUs, and the regenerator may be located several hundred feet in the air.

4.9 Catalytic Cracking Unit (CCU) Catalyst Regeneration Vents

The CCU (fluid or other) is used to upgrade the heavy distillates to lighter, more useful distillates, such as heating oils or gasoline. Nearly all CCU systems operate as fluidized-bed

reactors and use air or oil gas flow to transport the catalyst between the CCU reactor and the CCU regenerator. These fluid CCU (FCCU) systems represent more than 97 percent of the U.S. CCU capacity. A few thermal CCU (TCCU) exist, which use larger catalyst particles and moving bed reactors. Although the attributes of particulate matter emissions from FCCU and TCCU regenerators can differ widely, the HAP constituents emitted from the regeneration process are essentially the same.

During the cracking process, coke is deposited on the catalyst, and catalyst activity decreases. Therefore, the catalyst is recirculated between the reactor and the regenerator to burn off the coke deposits and reactivate the catalyst. There are two basic types of CCU regenerators: complete combustion regenerators and partial combustion regenerators. In a complete combustion regenerator, the regenerator is typically operated at approximately 1,200 to 1,400°F with excess oxygen and low levels (< 500 ppmv) of carbon monoxide (CO) in the exhaust flue gas. In a partial (or incomplete) combustion regenerator, the regenerator is typically operated at approximately 1,000 to 1,200°F under oxygen-limited conditions and relatively high levels (1 to 3 percent) of CO. Nearly all partial combustion CCU regenerators operate a CO boiler, incinerator, or other thermal combustion unit to complete the combustion of CO and to destroy products of incomplete combustion.

There are two general classes of HAP emissions from the CCU catalyst regenerator: metal HAPs (such as nickel, manganese chromium, and lead) that are associated with catalyst particles entrained in the exhaust gas; and organic HAPs (such as benzene, formaldehyde, hydrogen cyanide, phenol, and PAHs) that result from the incomplete combustion of coke or other impurities in the CCU reactor feed that deposits on the catalyst particles.

The 2000 Worldwide Refining Survey data were supplemented with data available from the MACT II project database. The additional data provided information on the number of CCUs at each refinery, the capacity for each CCU, the type of regenerator (complete vs. partial combustion), and the presence of additional control devices effective for the organic or metal HAP emission control. Organic HAP control device information was available for approximately 95 percent of the CCUs based on capacity, and metal HAP control device information was available for all CCUs.

4.9.1 Emission Estimation Methodology

For organic emissions, emission factors developed during the MACT II rulemaking were used. These emission factors, which are presented in Table 4-28, were developed based on data for units controlled for organic HAPs (i.e., either complete combustion or partial combustion followed by additional combustion). The emission factors for VOCs are generally based on five to six emission source tests; the emission factors for PAHs and furans are generally based on one or two emission source tests. Emissions of uncontrolled organic HAPs were estimated assuming a control efficiency of 98 percent (so that uncontrolled emissions are 50 times higher than controlled emissions); based on the current MACT II data, only one FCCU is uncontrolled for organic HAPs.

Table 4-28. Organic HAP Emission Factors for CCU Catalyst Regenerator Vent

CASRN	Compound	Emission Factor (lb/MMbbl)[a]
106-99-0	1,3-Butadiene	0.025
75-07-0	Acetaldehyde	25
71-43-2	Benzene	19
57-12-5	Cyanide	32
50-00-0	Formaldehyde	476
74-90-8	HCN	104
108-95-2	Phenol	21
108-88-3	Toluene	1.4
1330-20-7	Xylene	3.2
100-41-4	Ethylbenzene	0.242
67-64-1	Acetone	4.8
107-02-8	Acrolein	1.01
74-83-9	Bromomethane	2.1
75-15-0	Carbon disulfide	0.563
75-09-2	Methylene chloride	6.68
75-69-4	Trichlorofluoromethane	2.4
57117-31-4	PCDF	5.5E-07
57117-44-9	HCDF	1.1E-06
7647-01-0	HCl	141
83-32-9	Acenaphthene	0.0033
208-96-8	Acenaphthylene	0.129
120-12-7	Anthracene	0.102
56-55-3	Benzo(a)anthracene	0.00106
50-32-8	Benzo(a)pyrene	0.0106
205-99-2	Benzo(b)fluoranthene	0.0035
192-97-2	Benzo(e)pyrene	0.000845

(continued)

Table 4-28. (continued)

CASRN	Compound	Emission Factor (lb/MMbbl)[a]
191-24-2	Benzo(g,h,i)perylene	0.0046
207-08-9	Benzo(k)fluoranthene	0.00272
218-01-9	Chrysene	0.00327
53-70-3	Dibenz(a,h)anthracene	0.0042
206-44-0	Fluoranthene	0.221
86-73-7	Fluorene	0.058
193-39-5	Indeno(1,2,3-cd)pyrene	0.00438
91-20-3	Naphthalene	1.12
85-01-8	Phenanthrene	0.353
129-00-0	Pyrene	0.00327
91-57-6	2-Methylnaphthalene	0.0261
65-85-0	Benzoic acid	79.3
117-81-7	Bis(2-ethyl hexyl)phthalate	2.84
84-74-2	Di-n-butylphthalate	1.98
84-66-2	Diethylphthalate	0.282

[a] Emission factors for CCUs controlled for organics in lbs per million barrels of CCU capacity

Estimates of metal HAP emissions were based on the emissions of nickel (Ni) estimated from a Monte Carlo simulation of CCU emissions developed during the MACT II rulemaking. Nickel emissions were based on actual emissions data or on a hierarchy of available data for each CCU. This hierarchy is as follows:

1. Actual Ni emissions test data for that CCU;

2. Actual particulate matter test data for the CCU combined with reported equilibrium catalyst (E-Cat) Ni concentrations;

3. Actual particulate matter test data for the CCU and a randomized Ni fines concentration based on the distribution of fines data obtained from catalyst vendor;

4. Random particulate matter emission rate based on the presence of a particulate matter control device and particulate matter emission distributions for controlled

and uncontrolled units combined with reported E-Cat Ni concentrations for that CCU; and

5. Random particulate matter emission rate based on the presence of a particulate matter control device and particulate matter emission distributions for controlled and uncontrolled units combined with a randomized Ni fines concentration based on the distribution of fines data obtained from catalyst vendor.

An arithmetic average emission rate for each CCU was calculated from the 1,000 randomized runs performed for the Monte Carlo analysis, and these emission rates were directly input into the CCU emissions database. There are 127 CCUs in the database; direct Ni emissions data were available for 22 CCUs. Particulate matter emissions data were available for 51 refineries, and Ni E-Cat concentrations were available for 61 refineries.

Once the Ni emissions were included in the database, emissions from other metal HAPs were estimated based on the ratio of emission rates measured for these compounds to the emissions of Ni. Approximately 10 emission source tests measured multiple metal HAPs. The ratios used to estimate the emissions of the metal HAPs based on Ni emissions are presented in Table 4-29.

Table 4-29. Ratio of CCU Metal HAP Emissions to Nickel Emissions

CASRN	Compound Name	Ratio
7440-36-0	Antimony	0.233
7440-38-2	Arsenic	0.040
7440-41-7	Beryllium	0.0023
7440-43-9	Cadmium	0.065
7440-47-3	Chromium (total)	0.353
7440-48-4	Cobalt	0.035
7439-92-1	Lead	0.191
7439-96-5	Manganese	0.460
7439-97-6	Mercury	0.055
7440-02-0	Nickel	1.000
7782-49-2	Selenium	0.684

4.9.2 Source Characteristics

Stack parameters were available for roughly 30 CCUs based a preliminary risk assessment performed by API. Additional stack parameters are likely available in the particulate matter emissions source test reports, but these were not reviewed and compiled. Using these data, along with the process operating parameters collected in the MACT II rulemaking, the model stack parameters provided in Table 4-30 were developed.

Table 4-30. Model Stack Parameters for CCU Catalyst Regeneration Vent

CCU Catalyst Regenerator Configuration	Stack Height (ft)	Stack Diam.[a] (ft)	Stack Temp[b] (°F)	Flow Rate[c] (acfm)	Stack Velocity (ft/s)
CCU regenerator; no postcombustion unit	200	$2\cdot[\text{FlowRate}/\pi(\text{Vel}\times 60)]^{0.5}$	With WS: 300°F Non-WS: 550°F	$2\times CCU_{cap}\times (460+\text{Temp})/528$	70
CCU regenerator; with postcombustion unit	200			$2.8\times CCU_{cap}\times (460+\text{Temp})/528$	70

[a] Stack diameter calculated based on calculated flow rate and assumed stack velocity
[b] Default temperature for units with a wet scrubber (WS) is 300°F; default temperature for all other control device configurations is 550°F
[c] Flow rate calculated based on CCU capacity (CCU_{cap}) based on correlation developed from process data

4.9.3 Uncertainty in Estimates

Compared with many other sources, the CCU catalyst regenerator vent is relatively data-rich, especially with respect to Ni emissions, which are expected to be one of the main risk drivers from this source. Additionally, the relative ratio of Ni to other metal HAPs is generally consistent based on analysis of fines collected by particulate matter control devices on the CCU catalyst regenerator vent. The largest uncertainty lies with the emissions for mercury because mercury is not expected to be controlled well by the particulate matter control devices used for this vent (i.e., electrostatic precipitators (ESPs) or venturi scrubbers). Nonetheless, using the measured/calculated Ni emission rate and the emission ratios presented in Table 4-29, the nationwide mercury emissions from the CCU catalyst regenerator vent was estimated to be 1.29 tons/year. This emission rate is only 2.3 times lower than the emissions projected using the single highest emission factor derived from the mercury emissions data. Although the uncertainties increase when a given facility's emissions parameters are randomly assigned, the metal HAP emission estimates are considered to be accurate within a factor of 2 for most CCUs.

The CCU catalyst regenerator vent is the driving emission source for metal HAPs from the refinery. Therefore, the relatively high level of data and associated confidence in the metal

HAP emissions for the CCU catalyst regenerator vent leads to a relatively high level of confidence for the refinery-wide metal HAP emissions.

The organic emission factors for volatiles are based on midrange estimates, so the high-end emissions are generally no more than a factor of 2 higher than those estimated. The low-end emissions may be an order-of-magnitude less than those estimated using the emission factors presented in Table 4-28. The highest uncertainty lies with emissions that are uncontrolled for HAPs. Fortunately, only one facility is currently projected to be uncontrolled for organic HAPs. Uncontrolled formaldehyde emissions are most suspect. Formaldehyde is generally formed as a combustion product with some excess oxygen, and it is unlikely that uncontrolled formaldehyde emissions are 50 times those of controlled units. Additionally, because the industry trend has been toward complete combustion CCUs, the one CCU uncontrolled for organics should be contacted to verify that it has not modified its CCU operation (i.e., it still uses a partial combustion unit with no postcombustion device). The CCU regenerator vent is a relatively minor contributor to the overall benzene emission, but it is a major contributor to formaldehyde, cyanide, and hydrogen cyanide (HCN) emissions.

Based on the lack of data for the PAH and furan emissions, the emission estimates for these compounds have high uncertainties, likely an order of magnitude either high or low. The CARB, with the support of EPA, did conduct an emissions source test at a complete combustion FCCU (with no postcombustion device). The only dioxin isomer detected in all runs was OCDD (octachloro-dibenzo-p-dioxin); OCDF (octachloro-dibenzo-p-furan) and hetpa-CDD (hetpachloro-dibenzo-p-dioxin) were detected in one run; all dioxin/furan quantities that were detected were detected at levels below the method quantitation limit for the analysis. All PCBs isomers were below detection limits; data for PAHs have not yet been reported. This additional source test was not included in the development of the MACT II emission factors, but it confirms low emissions of these compounds from the CCU catalyst regenerator vent.

4.10 Sulfur Recovery Unit (SRU) / Sulfur Plant Vents

All crude oils contain some sulfur compound impurities. Sulfur compounds are converted to hydrogen sulfide (H_2S) in the cracking and hydrotreating processes of the refinery. The H_2S or "acid gas" is removed from the process vapors using amine scrubbers. The amine scrubbing solution is subsequently heated to release the H_2S, and the acid gas is treated in the sulfur recovery plant to yield high-purity sulfur that is then sold as product. The sulfur recovery plant consists of one or more SRUs operated in parallel and may also contain one or more catalytic tail gas treatment units and/or a thermal oxidizer.

The primary HAP components of the final sulfur plant vent are carbonyl sulfide (COS) and carbon disulfide (CS_2). These HAP components are by-products of the SRU and tail gas treatment unit (TGTU) reactions; COS may also be a product of incomplete combustion from a thermal oxidizer.

The 2000 Worldwide Refining Survey data were supplemented with data available from the MACT II project database. The additional data provided information on the number of SRUs

at each refinery, the capacity for each SRU, the type of SRU (most are Claus units), and the presence and type of TGTU and/or thermal oxidizer. Process-specific information was available for approximately 90 percent of the SRUs based on sulfur production capacity.

4.10.1 Emission Estimation Methodology

The MACT II BID (U.S. EPA, 1998b) presents a range of total sulfur HAP compound emission factors for SRU controlled by an incinerator. Based on the data presented and additional concentration data submitted by National Petrochemical and Refiners Association (NPRA), it was assumed that 75 percent of the sulfur HAPs emitted in COS and 25 percent in CS_2. Emissions of uncontrolled sulfur HAPs were estimated assuming a control efficiency of 98 percent (so that uncontrolled emissions are 50 times higher than controlled emissions). The emission factors used in the analysis are presented in Table 4-31. The controlled emission factors are based on summary data reported for five SRUs.

Table 4-31. Emission Factors for Uncontrolled SRUs

CASRN	Compound Name	Controlled SRU Emission Factor (lb/lton)[a]	Uncontrolled SRU Emission Factor (lb/lton)[a]
463-58-1	Carbonyl sulfide	0.117	5.85[b]
75-15-0	Carbon disulfide	0.040	2.00[b]

[a] Emission factor in lbs HAP per long-ton of sulfur produced
[b] Values estimated at 50 times the controlled SRU emission factor

The controlled emission factor was applied for all units that operated a TGTU, an incinerator, or both. For units for which control device information was unavailable, 50 percent of the uncontrolled emission factor was used. This is likely an overestimate of the emissions because every SRU for which information was available operated either a TGTU or an incinerator.

4.10.2 Source Characteristics

The few stack parameters that were available for the SRU vent all employed a thermal oxidizer. From these data, the model stack parameters presented in Table 4-32 were developed. These model stack parameters are suitable for units with an incinerator (the most prevalent control device), but the stack temperatures may be high for certain types of TGTUs.

Table 4-32. Model Stack Parameters for SRU Vent

SRU Production Capacity	Stack Height (feet)	Stack Diam. (feet)	Stack Temp. (°F)	Flow Rate[a] (acfm)	Stack Velocity (ft/s)
<100 ltons/day	175	3	1,200	Calculated: $65 \times SRU_{cap} \times (460+Temp)/528$	Calculated: Flow ÷ $[60 \times \pi \times (Diam/2)^{0.5}]$
≥100 ltons/day	175	5	1,200		

[a] Flow rate calculated based on SRU production capacity (SRU_{cap}) based on correlation developed from available process data

4.10.3 Uncertainty in Estimates

The HAP emission factors for SRU vents are based on limited data. However, the emission data that were available were rather consistent so that the controlled emission factors are likely accurate to within a factor of 2. The uncontrolled emission factors are more highly speculative. These emission factors were divided by 2 and applied to units that did not report TGTU or incinerator information. Although control device configuration information was available for more than 90 percent of the sulfur production capacity, the high emission factors attributed to those units without information resulted in two-thirds of the SRU HAP emissions originating from those units. Based on the prevalence of controls at units that have control configuration information, the application of half the uncontrolled emission factor for SRUs with missing data is considered to be a highly conservative assumption.

4.11 Miscellaneous Process Vents

Miscellaneous process vents include those associated with distillation units, flash or knockout drums, reactors, caustic wash accumulators, and overheads from scrubbers, strippers, and wash towers. Process vents associated with catalyst regeneration for catalytic reforming and catalytic cracking and the sulfur recovery vent were addressed separately, as previously described. There were few data available to characterize these miscellaneous process vent emissions, and the preliminary emissions estimates provided for the risk assessment runs did not include estimates for these emission sources. Based on information from Petroleum Refinery MACT I, most of these process vents are controlled. A methodology is presented to estimate emissions from these vent sources based on current information.

4.11.1 Emission Estimation Methodology

Accurate estimates of emissions from process vents are difficult to obtain because of the lack of HAP data and site-specific information on whether they are controlled. A review of the permit applications for the nine Louisiana refineries indicated they did not report any miscellaneous process vents with significant HAP emissions. Several plants reported process

vents that were vented to some type of combustion device. For example, the noncondensibles or tail gas from the vacuum and crude distillation units were sent to the RFG system at one plant, and another plant burned them in a process heater. Other process vents were also reported to be sent to the RFG system or to a flare. Although process vents at these plants appear to be controlled, other plants for which we have little information may vent certain units to the atmosphere. The effort is also complicated by the lack of information on how plants implemented the requirements for Petroleum Refinery MACT I. The rule requires that process vents at existing sources be controlled if they contain 20 ppmv or more VOCs and emit 33 kg/day or more VOCs.

The approach used to estimate emissions relies on the nationwide estimates of the impacts of MACT I . The estimates before and after control (i.e., before and after MACT I) are given in Table 4-33. These emissions were distributed among the 155 refineries in the database using the crude oil capacity. The estimates for "after control" were divided by the nationwide crude oil capacity (17 million bbl/day) to generate the emission factors in the table. An example calculation is given below for benzene emissions from process vents at a refinery with 100,000 bbl/day crude oil capacity:

Benzene (tpy) = 100,000 bbl/day × 1.8E-5 tpy/bbl/day = 1.8 tpy.

Table 4-33. Process Vent Emission Estimates from MACT I

HAP	Process Vent Emissions (tpy)		Emission Factor (tpy per bbl/day crude)
	Before Control	After Control	
2,2,4-Trimethylpentane	2,749	605	3.6E-05
Benzene	1,409	310	1.8E-05
Cresols	0.41	0.09	5.3E-09
Cumene	23	5.5	3.2E-07
Ethylbenzene	124	27.5	1.6E-06
Hexane	6,934	1,526	9.0E-05
Methyl-t-butyl ether	868	191	1.1E-05
Naphthalene	1.1	0.2	1.2E-08
Phenol	1.1	0.2	1.2E-08
Styrene	22	4.4	2.6E-07
Toluene	1,398	308	1.8E-05
Xylene	404	89	5.2E-06
Totals	0	0	

4.11.2 Source Characteristics

As with HAP emissions data, there is little information with which to characterize process vents. The characteristics are expected to be quite variable, depending on the specific plant and associated processes. The only process vent found in the 1996 NTI was for the condenser on vacuum distillation units. The vent height ranged from 10 ft to 200 ft, and the diameter ranged from 1.5 ft to 11 ft. The velocity ranged from 13 ft/s to 56 ft/s. Midrange values of 105 ft in height, 6 ft in diameter, and 35 ft/s are recommended.

4.11.3 Uncertainty in Estimates

As discussed earlier, the HAP emission estimates for process vents are uncertain because of the lack of site-specific information, including which vents at which plants are uncontrolled. The emission estimates for MACT I suggest that the nationwide emissions of HAP from process vents are not as significant as other emission points at refineries. However, process vent emissions may make a significant contribution to emissions at any refineries where these vents are not controlled. Site-specific information on uncontrolled process vents could provide a significant improvement in the emission estimates and reduce uncertainty.

5.0 Additional Data Collection

The database documented in this report is expected to be an improvement over other available databases for petroleum refineries because it is more complete with respect to the populations of refineries, emission points, and HAPs. However, during the development of this database, which took place over a relatively short time frame, some weaknesses were identified that may merit the collection of additional information to provide more accurate and defensible estimates. In addition, areas where additional information would be of little value were also identified to assist in focusing any additional data collection effort.

5.1 Recommendations for Additional Data Collection

The recommendations focus on the emission points that are the biggest contributors to HAP emissions and also those for which data should be available at individual refineries to improve the estimates. Information that would improve the estimates of **fugitive equipment leaks** includes Method 21 inspection results (site-specific data on leak frequency and screening levels when leaks are detected), HAP composition of process streams, and counts of individual components (such as pumps, valves, and flanges) by process. These data are especially needed for aromatic units because no process component counts or compositional data are currently available for aromatics units. For **wastewater treatment processes**, information on the quantity of HAPs processed in open wastewater collection and treatment systems and emissions from any control devices (such as thermal oxidizers or strippers) would be helpful. Additionally, wastewater generation rates and composition data for aromatics units are needed. For **process and storage tanks**, site-specific emission estimates generated by the companies using EPA's AP-42 procedures (*TANKS* software) would improve the estimates. Such site-specific estimates are likely to have been generated already for state or Toxics Release Inventory (TRI) emission inventories, and the companies are in the best position to develop accurate estimates based on their knowledge of throughput and composition. Specific product production rates for aromatic compounds could greatly improve product storage tank emission estimates. In general, **aromatic units** could be targeted for the collection of more-detailed, process-specific data.

Site-specific data for **cooling towers** could significantly improve emission estimates, especially for plants that monitor the cooling water. This information would include the volumetric flow rate for the water and the composition of the process streams where it is used. Any measurement data on the HAP content or THC before the water is exposed to the atmosphere would also be helpful. Finally, information on **uncontrolled process vents** is needed. Plants could identify the processes and vents, describe their use (e.g., whether continuous or periodic or infrequent venting), and provide emissions data or estimates for THC or specific HAPs. With respect to characteristics of emission points, additional information for cooling towers and uncontrolled process vents is needed to supplement the sparse available data.

This information would include height, area, linear flow rate, volumetric flow rate, and temperature.

5.2 Recommendations for Not Collecting Additional Data

There are likely to be no additional useful emissions data for process **heaters, boilers, and flares**. A detailed study has already been performed for process heaters and boilers, and flares are not amenable to testing. In addition, the characteristics of these emission points are reasonably well characterized from available data.

The available data for the **MACT II emission points** also appear adequate and already include many site-specific features. Additional HAP emissions data are not likely to be obtained because the nine Louisiana refineries generally did not include them in their permit applications, and other databases, such as the TRI, generally do not include emissions estimates for the full range of HAPs emitted from these sources. These vents include the **catalytic regeneration vents** associated with catalytic cracking and catalytic reforming, and the **sulfur recovery vent**.

The review of available data indicates that emissions from **loading product** into marine vessels, tank trucks, and rail cars are generally controlled. Because these emissions appear to make only a small contribution to total emissions, additional information would probably be of little value. In addition, **process vents that are controlled** by venting to a combustion device do not make a significant contribution to total emissions, and to some extent, their contribution is accounted for in the emission factors for process heaters, boilers, and flares.

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Appendix A. Data Extracted from Louisiana Permit Applications

A.1 Overview

Personnel from EC/R visited the Office of Air Quality at the Louisiana Department of Environmental Quality and extracted information from their files. One of the most useful items was an emission inventory questionnaire that petroleum refineries submitted for each emission point in their application for a Part 70 operating permit. The questionnaire included a description of the emission point, its UTM coordinates, and characteristics (stack height and diameter, exit temperature, flow rate, velocity, operating time, and operating rate). For combustion sources, the type of fuel and heat input were specified, and for tanks, the volume was reported. The questionnaire also included a list of the pollutants emitted, the average and maximum rates (lb/hr), and annual average rate (tpy). Most of these applications were submitted in the 1996 to 2000 time frame. Figure A-1 shows an example of a questionnaire response.

The applications were obtained for nine refineries that spanned a wide range of crude oil capacity (from 50,000 to 500,000 bbl/day). The refineries have a representative mix of processes typical of refineries nationwide. This information was used to characterize the emissions and emission points at these refineries in great detail and were also used to extrapolate to other refineries for which information was not available. The most useful information was for emissions from fugitive equipment leaks, wastewater treatment, storage and process tanks, product loading, and flares.

A.2 Details

The emission estimates provided by the companies were generally developed from EPA estimating procedures using site-specific data. However, not all emission points or HAP were included. For example, the company estimates were supplemented by the estimating procedures described in Section 4 to fill in data gaps for HAP from heaters and boilers, catalyst regeneration vents, and sulfur recovery. The results for benzene emissions (a HAP found at all refineries that is a carcinogen of primary interest) are shown in Figure A-2 and tabulated in Table A-1 by emission point. The diamond data points represent the company's estimates and show internal consistency in that (as would be expected) benzene emissions increase with refinery capacity. The circles are the estimates derived for the risk assessment and include emission points that were not in the questionnaire responses. The results for benzene emissions for Marathon Oil appear to somewhat out of line with the others in terms of capacity.

Table A-2 gives plant totals for emissions of the most commonly reported HAPs. One of the most detailed responses was that for BP Oil – Belle Chasse (now Tosco Refining). Tables A-3 through A-6 provide a summary of emissions by type of emission point for different processes and provides insight into the major contributors to HAP emissions. This level of detail was not available for all of the plants. Table A-7 is a listing of each of the emission points reported by the nine refineries and the characteristics. Table A-7 gives the HAP emissions estimates for each emission point. (The key to the facility ID is given in Table A-1.)

FIGURE A-1. EXAMPLE OF EMISSION INVENTORY FORM

Department of Environmental Quality
Air Quality Division
P.O. Box 82135
Baton Rouge,LA 70884-2135
(504) 765-0219

LOUISIANA

SINGLE POINT SOURCE/AREA/VOLUME SOURCE
Emission Inventory Questionnaire (EIQ)
for Air Pollutants

LDEQ

Company Name: BP Oil Company

Plant location and name (if any): Belle Chasse, Alliance Refinery

Date of Submittal: October 12, 1996

Source Id Number: 406-D-15

Descriptive name of the equipment served by this stack or vent: Marine Vapor Recovery Flare #1

Location of stack or vent (see instructions on how to determine location of area sources)
UTM zone no. [ ] 15 Horizontal coordinate 212593 mE
[X] 16 Vertical coordinate 3286725 mN

Stack and Discharge Physical Characteristics Change __ Y _x_ N	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) [X] ft [ ] ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals) and date of construction
	25	3	1600	53333	125.8	N/A

Fuel	Type of fuel used and heat input (see instructions)		Operating Characteristics	Percent of annual throughput of pollutants through this emission point			Normal operating time of this point		Normal operating rate
	Type of Fuel	Heat input (MM BTU/hr)		Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
a	Natural Gas	64.9		25	25	25	25	24	7	52	782,240 Mgal/yr
b											
c											

AIR POLLUTANT SPECIFIC INFORMATION

Pollutant	Control Equipment Code	Control Equipment Efficiency	Emission Rate Average (lbs/hr)	Emission Rate Maximum (lbs/hr)	Emission Rate Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
PM 10	000	0	0.4001	0.4001	0.6538	3		ppm by vol
Sulfur Dioxide	000	0	0.0387	0.0387	0.0632	3		ppm by vol
Nitrogen Oxides	000	0	9.0810	9.0810	14.84	3		ppm by vol
Carbon Monoxide	000	0	2.2860	2.2860	3.735	3		ppm by vol
NMNE HC (excluding those below)	000	0	14.5744	72.9040	19.92	3		ppm by vol
Benzene	000	0	7.4585	56.6244	1.842	3		ppm by vol
Cumene	000	0	0.0010	0.0048	0.0001	3		ppm by vol
Cyclohexane	000	0	0.0220	0.1102	0.0202	3		ppm by vol
Ethylbenzene	000	0	0.0103	0.0514	0.0086	3		ppm by vol
Methyl Tert Butyl Ether	000	0	2.4949	12.4836	2.777	3		ppm by vol
N-Hexane	000	0	7.5681	18.9524	6.6852	3		ppm by vol
Naphthalene	000	0	0.0003	0.0015	0.0002	3		ppm by vol
Toluene	000	0	0.1499	0.7495	0.1207	3		ppm by vol
1,2,4 - Trimethylbenzene	000	0	0.0147	0.0735	0.011	3		ppm by vol
2,2,4 - Trimethylpentane	000	0	0.0090	0.0226	0.0007	3		ppm by vol
1-methylnaphthalene	000	0	0.0002	0.0004	0.0001	3		ppm by vol
2-methylnaphthalene	000	0	<0.001	<0.001	<0.001	3		ppm by vol
Xylenes (mixed isomers)	000	0	0.0882	0.4409	0.0666	3		ppm by vol

FIGURE A-2. BENZENE EMISSION ESTIMATES FOR LA REFINERIES

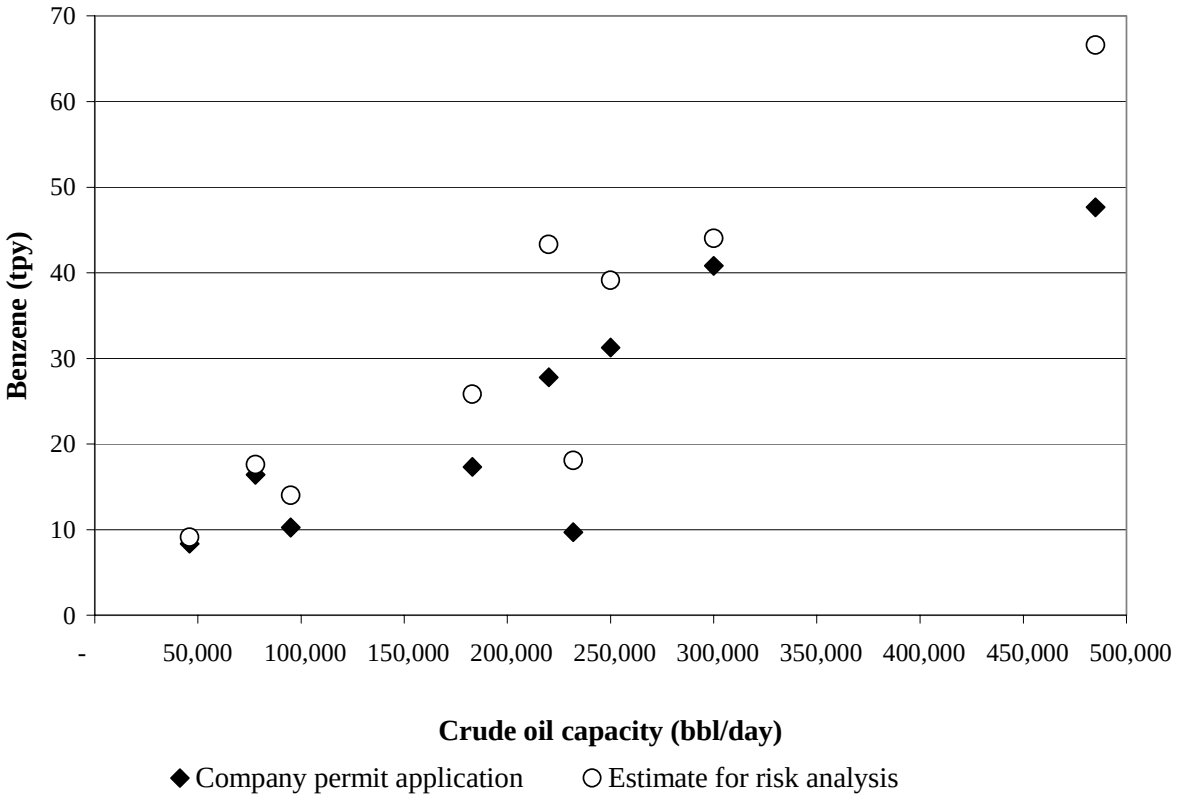

TABLE A-1. BENZENE EMISSION POINTS

ID	Refinery	Benzene emissions (tons/yr)					
		Fugitives	Wastewater	Tanks	Flares	Loading	Total
70	Pennzoil, Shreveport	3.0	3.2[c]	1.5	0.7	--	8.4
74	Valero, Krotz Springs	5.1	9.8	0.8	--	0.5	16
68	Murphy, Meraux	9.0	0.4	0.6	0.08	0.2	10
64	Exxon, Chalmette	15.8[b]	--	1.5	--	0.01	17
67	Shell, Norco	9.6	--	15.6	2.4	0.22	28
65	Marathon, Garyville	2.0	3.6	1.8	0.03	2.1	9.5
73	BP, Belle Chase	9.3	9.2	8.3	--	4.3[a]	31
61	Citgo, Lake Charles	13.2	4.4	21.7	1.3	0.2	41
63	Exxon, Baton Rouge	12.9	14.1	18.8	--	1.8	48

[a] Includes flares; [b] Includes wastewater treatment; [c] Inludes cooling tower

TABLE A-2. HAP EMISSION ESTIMATES FROM TITLE V PERMIT APPLICATIONS

			HAP Emissions (tons/year)							
Plant	**City**	**Crude(bbl/day)**	**Benzene**	**Toluene**	**Xylene**	**MtB ether**	**Hexane**	**Formaldehyde**	**Naphthalene**	**Ethyl benzene**
Pennzoil	Shreveport	46,000	8.4	106	22.4	0.0	44.4	0.0	0.1	4.3
Valero	Krotz Springs	78,000	16.4	19.6	25.7	26.6	51.4	6.8	0.8	5.4
Murphy Oil	Meraux	95,000	10.3	7.2	4.6	13.7	22.6	0.1	0.0	0.7
ExxonMobile	Chalmette	183,000	17.3	91.9	132	1.4	10.2	0.0	1.7	10.6
Shell	Norco	220,000	27.9	58.8	28.9	0.0	45.9	0.0	5.4	20.0
Marathon Oil	Garyville	232,000	9.7	23.7	26.1	3.0	31.6	0.2	0.7	3.3
BP-Alliance	Belle Chase	250,000	31.3	27.7	56.3	15.3	12.2	0.0	0.3	11.1
Citgo	Lake Charles	300,000	40.8	28.5	24.8	11.0	54.4	0.0	1.3	4.6
Exxon	Baton Rouge	485,000	47.7	116	87.7	207	76.6	0.0	10.0	36.7

			HAP Emissions (tons/year)						
Plant	**City**	**Crude(bbl/day)**	**Biphenyl**	**Cumene**	**1,3 Butadiene**	**MEK**	**MIBK**	**2,2,4Trimethylpentane**	**PNA/PAH**
Pennzoil	Shreveport	46,000	0.0	0.4	0.0	174*	0.0	0.0	0.0
Valero	Krotz Springs	78,000	0.0	0.5	0.3	0.0	0.0	1.1	21
Murphy Oil	Meraux	95,000	0.0	0.0	0.2	0.0	0.0	0.0	0.0
ExxonMobile	Chalmette	183,000	0.2	0.2	0.1	0.0	0.0	10.0	0.0
Shell	Norco	220,000	0.0	0.0	9.3	0.0	0.0	0.0	0.0
Marathon Oil	Garyville	232,000	0.0	0.1	0.0	0.0	0.0	3.5	0.0
BP-Alliance	Belle Chase	250,000	0.0	2.2	0.5	0.0	0.0	0.0	0.0
Citgo	Lake Charles	300,000	0.0	0.1	0.2	0.0	0.0	0.0	2.6
Exxon	Baton Rouge	485,000	1.3	1.9	0.3	379*	167*	64	21

* The emissions of ketones are associated with dewaxing processes at these plants.

TABLE A-3. BP EQUIPMENT LEAKS - FUGITIVE EMISSIONS

Process	Emissions (tons/yr)							
	Benzene	Toluene	Xylene	Hexane	Naphthalene	Ethyl benzene	Cumene	1,3 butadiene
aromatic extraction	3.40	4.70	3.90	0.52	0.01	1.10	0.80	
benzene-hydrodealkylation	2.70	3.20	2.50	0.32	0.00	0.77	0.49	
catalytic reforming	0.67	1.50	1.20	0.39	0.09	0.29	0.03	0.19
crude unit	0.25	0.46	0.58	1.50	0.06	0.16	0.03	0.01
hydrotreater (diesel)		0.02	0.03	0.01	0.01			
light ends recovery	0.14	0.09	0.01	0.12		0.09		0.18
merox unit	0.01	0.05	0.01	0.01			0.01	
naphfining	0.00	0.12	0.14	0.13	0.00	0.03	0.00	
saturate gas unit	0.20	0.14	0.14	0.30	0.00	0.48	0.01	
fugitives-nonSOCMI tank farm	0.38	2.07	1.62	0.58	0.14	0.37	0.05	
fugitives-SOCMI tank farm	1.53	2.12	1.73	0.23		0.49	0.36	
Total	**9.28**	**14.47**	**11.86**	**4.11**	**0.32**	**3.78**	**1.78**	**0.38**

TABLE A-4. EMISSIONS FROM BP WASTEWATER TREATMENT

Unit	Emissions (tons/yr)			
	Benzene	Toluene	Xylene	Ethyl benzene
biological treatment	0.09	0.03	0.14	0.07
cooling tower	0.54	0.15	0.12	0.04
fugitives-WW collection and treatment	6.30	7.00	10.00	2.10
skimmed oil tank	0.02	0.01	0.00	
tank-equalization	0.88	1.10	0.00	
tank-neutralized caustic	0.01	0.03	0.03	0.01
tank-neutralized caustic	0.01	0.03	0.03	0.01
tank-storm water	0.02	0.01	1.30	
tank-storm water	0.02	0.01	1.30	
thermal oxidizer-wwt	1.34	0.17	0.26	0.06
Total	**9.22**	**8.53**	**13.19**	**2.28**

TABLE A-5. EMISSIONS FROM BP TANKS

Tank contents	Emissions (tons/yr)				
	Benzene	**Toluene**	**Xylene**	**Hexane**	**Ethyl benzene**
Benzene	1.7				
Crude oil	0.05	0.02	0.01	0.03	
Distillates	0.7	0.7	0.5	0.3	0.2
Gasoline	0.09	0.1	0.03	0.02	0.01
Heavy blending	0.2	0.2	0.04	0.02	0.01
Light gas blending	0.5	0.6	0.2	0.1	0.04
Naphtha	0.05	0.02	0.01	0.03	0.01
Other petrochemicals	1.5	0.5		0.01	0.04
Swing tanks	3.5	1.7	0.6	0.2	0.05
Slop gasoline	0.02	0.01	0.01	0.02	0.01
Slop oil	0.03	0.05	0.01	0.01	0.01
Xylene			0.26		
Total	**8.34**	**3.9**	**1.67**	**0.74**	**0.38**

TABLE A-6. EMISSIONS FROM BP MARINE VESSEL LOADING

Unit	Emissions (tons/yr)						
	Benzene	**Toluene**	**Xylene**	**MTB Ether**	**Hexane**	**Naphthalene**	**Ethyl benzene**
flare	1.80	0.12	0.07	2.80	0.69		0.01
flare	1.80	0.12	0.07	2.80	0.69		0.01
Fugitives	0.30	0.11	0.09		3.00	0.01	0.06
Fugitives	0.30	0.11	0.09		3.00	0.01	0.06
Product dock loading	0.07	0.16	14.60				2.30
Product dock loading	0.07	0.16	14.60				2.30
Total	**4.34**	**0.78**	**29.52**	**5.60**	**7.38**	**0.02**	**4.74**

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
61	CVS area	3xxx3	cooling tower	50000	gal/min									
61	marine vessel loading	3ix34	flare										469143	3337646
61	marine vessel loading	3ix35	flare				100	4.6		1832			469215	3338134
61	Lift station	3ix38	flare				51	1.6					468162	3337773
61	flare	3ix41	flare- S central CVS	3	MM Btu/hr		180	2.5		1832			468723	3338573
61	fugitives	3misc6	fugitives-miscellaneous										468900	3338500
61	straight run fractionator heater	3vii1	heater	60.65	MM Btu/hr	RFG	115.5	5.6		580			469685	3338556
61	crude charge furnace	3xxx1	heater	300	MM Btu/hr	RFG	200	7		300	104400	45	469105	3339266
61	vacuum charge furnace	3xxx2	heater	500	MM Btu/hr	RFG	200	10		400	231000	49	469068	3339266
61	alcohol tanks	3ix29	tank-alcohol FR 3 tanks										468696	3338444
61	aromatics tanks	3ix24	tank-aromatics FR 13 tanks										468681	3338367
61	crude oil tanks	3ix14	tank-crude FR 20 tanks										467498	3337786
61	distillate tanks	3ix22	tank-distillate fixed-12 tanks										467760	3338002
61		3ix33	tank-garage 3 tanks										469249	3338500
61	gasoline tanks	3ix17	tank-gasoline FR 10 tanks										467870	3338267
61	gasoline tanks	3ix15	tank-gasoline FR 22 tanks										466330	3337786
61	gasoline tanks	3ix18	tank-gasoline FR 4 tanks										467670	3337686
61	heavy naphtha	3ix30	tank-heavy naphtha fixed 6 tanks										468086	3338892
61	kerosene tanks	3ix21	tank-kerosene FR 11 tanks										467475	3337844
61	naphtha tanks	3ix16	tank-naphtha FR 4 tanks										467628	3338002
61		3ix42	tank-slop FR-7 tanks										467800	3338360
61	wastewater treatment	3ix37	wastewater treatment										468345	3339891
63	tank farm	tanks-cb	catch basin										675140	3373350
63	lube, dewax, hydrofining	96	condensate blowdown drum										674900	3374000
63	hydroprocessing	hydro-ct	cooling tower										674760	3373700
63	distillation-"pipestill"	psla-ct	cooling tower										675138	3373687
63	Reformer	reform-ct	cooling tower										674352	3373395
63	alkylation - light ends	vle-ct	cooling tower										674897	3373226
63	wastewater treatment	wcla-off	figitives-offsite										675120	3373580
63	docks complex	91/92	flare				66.8	13.8		1800	605000	67.1	673550	3373550
63	light hydrocarbon recovery	c3st-fug	fugitives										674311	3373010
63	docks complex	docks-fug	fugitives										673336	3373013
63	hydroprocessing	hydro-fug	fugitives										674760	3373700
63	light oil finishing	lofu-fug	fugitives										674195	3373325
63	docks complex	m-fug	fugitives										674873	3380699

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
63	distillation-"pipestill"	psla-fug	fugitives										675138	3373687
63	Reformer	reform-fug	fugitives										674372	3373544
63	lube, dewax, hydrofining	spec-fug	fugitives										674904	3374024
63	tank farm	tanks-fug	fugitives										675140	3373350
63	alkylation - light ends	vle-fug	fugitives										674897	3373226
63	wastewater treatment	wcla-fug	fugitives										675120	3373580
63	distillation-"pipestill"	5	heater	229	MM Btu/hr		186	6.9		378	38192	17	675100	3373500
63	distillation-"pipestill"	6	heater	130	MM Btu/hr		124	4.9		352	16000	14.1	675100	3373500
63	distillation-"pipestill"	7	heater	180	MM Btu/hr		212	6.9		417	42700	19	675100	3373500
63	distillation-"pipestill"	8	heater	95	MM Btu/hr		149	5.6		546	22000	14.9	675100	3373500
63	distillation-"pipestill"	9	heater	290	MM Btu/hr		147	6		341	115	0.1	675100	3373500
63	distillation-"pipestill"	11	heater	130	MM Btu/hr		130	503		379	37		675100	3373500
63	distillation-"pipestill"	12	heater	290	MM Btu/hr		147	6		329	1163	0.7	675100	3373500
63	distillation-"pipestill"	14	heater	177	MM Btu/hr		130	5.3		407	1705	1.3	675100	3373500
63	distillation-"pipestill"	15	heater	394	MM Btu/hr		123	5		407	581	0.5	675100	3373500
63	distillation-"pipestill"	17	heater	142	MM Btu/hr		129	3.5		365	147	0.3	675100	3373500
63	Reformer	31	heater	151	MM Btu/hr		170.6	7.3		903	43726	17.3	674260	3373388
63	Reformer	32	heater	151	MM Btu/hr		188	8.8		911	50815	13.9	674260	3373388
63	Reformer	33	heater	117	MM Btu/hr		123.3	7.1		911	35085	14.8	674260	3373388
63	Reformer	34	heater	184	MM Btu/hr		87	5.3		901	52098	39.3	674260	3373388
63	Reformer	35	heater	55	MM Btu/hr		105	3.9		540	3530	4.9	674260	3373388
63	Reformer	36	heater	29	MM Btu/hr		75	6.9		824	2166	1	674260	3373388
63	Reformer	37	heater	47	MM Btu/hr		75	6.9		1119	12574	5.6	674260	3373388
63	Reformer	38	heater	110	MM Btu/hr		180	5.5		289	6673	4.7	674260	3373388
63	Reformer	39	heater	76	MM Btu/hr		180	4.8		533	16451	15.5	674260	3373388
63	Reformer	40	heater	123	MM Btu/hr		137	6.9		538	13702	6.1	674260	3373388
63	Reformer	41	heater	232	MM Btu/hr		172	8.2		657	46303	14.6	674260	3373388
63	hydroprocessing	42	heater	143	MM Btu/hr		160	8.9		541	17691	4.7	674760	3373700
63	hydroprocessing	43	heater	41	MM Btu/hr		135	3.9		491	5300	7.4	674760	3373700
63	hydroprocessing	44	heater	32	MM Btu/hr		135	3.9		463	6184	8.6	674760	3373700
63	sulfur recovery	68	heater	28	MM Btu/hr		221	4.6		1200	36225	36.4	674495	3372930
63	sulfur recovery	69	heater	28	MM Btu/hr		221	4.6		1200	35800	35.9	674495	3372900
63	hydroprocessing	76	heater	25	MM Btu/hr		100	5			1854	1.6	674950	3373800
63	Reformer	81	heater	72	MM Btu/hr		111	5.5		560	35564	24.9	674260	3373388
63	distillation-"pipestill"	10	heater - air preheat				156	7.9		360	79000	27	675100	3373500

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
63	distillation-"pipestill"	13	heater - air preheat				156	7.9		327	89500	30.4	675100	3373599
63	distillation-"pipestill"	16	heater - air preheat				146	8.9		374	105000	28.1	675100	3373500
63	lube, dewax, hydrofining	spec-solv	solvent emissions										674904	3374024
63	docks complex	m-tanks	tanks										674376	3380507
63	tank farm	ref-tanks	tanks										675140	3373350
64	boiler - steam	35	boiler	158	MMBtu/hr	RFG	65	4.7		272	52000	50	212958	3314932
64	boiler - steam	66	boiler	300	MMBtu/hr	RFG	62	7		350	105000	44.8	212880	3314925
64	boiler - steam	69	boiler	200	MMBtu/hr	RFG	60	5		300	70000		212955	3314947
64	boiler - steam	70	boiler	300	MMBtu/hr	RFG	62	7.05		350	105000	44.8	212955	3314947
64	FCCU	71	catalyst unloading	2.50E+04	lb/day								213195	3315256
64	FCCU?	27	CO boiler	320	MMBtu/hr	RFG	140	9		536	147040	38.5	212879	3314929
64	coker -API	1C	coker #1										212864	3314896
64	coker -API	2C	coker #2										212864	3314896
64	compressor	50	compressor	2.7	MMBtu/hr	NG	25	0.66		759	1235	60.1	212906	3314861
64	compressor	51	compressor	2.7	MMBtu/hr	NG	25	0.66		759	1235	60.1	212907	3314863
64	FCCU compressor	52	compressor	7	MMBtu/hr	NG	35	1.18		759	3154	48	213100	3314800
64	FCCU compressor	53	compressor	9.2	MMBtu/hr	NG	35	1.2		759	4146	61.1	212908	3314864
64	isom recycle compressor	56a	compressor	4.9	MMBtu/hr	NG	20	1		759	2208	47.1	212953	3314733
64	isom recycle compressor	56b	compressor	4.9	MMBtu/hr	NG	20	1		759	2208	47.1	212953	3314733
64	cooling tower	76	cooling tower	27619	gal/min								213203	3314769
64	loading -crude terminal	CTAPI	crude terminal										212864	3314896
64	flare	28	flare	165.5	MMBtu/hr	NG	181			200	21714		212520	3314800
64	flare	29	flare	125	MMBtu/hr	RFG	181	5.7		200	21714		212800	3314700
64	flare-loading	68	flare	5.7	MMBtu/hr	NG	35	3.2		1800	2800	16	212800	3314700
64	fugitives	FE	fugitives -leaks										213761	3321789
64	crude heaters	1	heater	154	MMBtu/hr	RFG	130	7.66		471	48930	17.4	212964	3314733
64	crude heaters	2	heater	154	MMBtu/hr	RFG	130	7.66		466	51018	18.1	212953	3314733
64	crude heaters	4	heater	88	MMBtu/hr	RFG	150	4.7		626	42028	40.4	212955	3314760
64	sulfolane hot oil	11	heater	120	MMBtu/hr	RFG	123	8.7		565	63100	17.7	212979	3314902
64	Reformer	14	heater	130	MMBtu/hr	RFG	116	8.7		780	72221	20.2	213052	3314900
64	reformer	20	heater	158	MMBtu/hr	RFG	160.6	9.4		455	71152	17.1	213077	3315030
64	pretreater charge	21	heater	26	MMBtu/hr	RFG	43	3.9		609	14056	19.6	213024	3315069
64	hydrocarbon recycle splitter	24	heater	50	MMBtu/hr	RFG	67.9	4.4		870	33000	35.6	213123	3315114
64	coker charge	26	heater	53	MMBtu/hr	RFG	150	5.8		1042	37711	23.8	212640	3315487
64	crude charge	37	heater	136	MMBtu/hr	RFG	170	7.2		613	65000	26.7	213132	3314795

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
64	reformer reheater	38	heater	50	MMBtu/hr	RFG	140	5.5		537	29619	20.8	213000	3314987
64	HDS charge	39	heater	40.4	MMBtu/hr	RFG	100	5		544	21590	18.3	212862	3314887
64	reformer	41	heater	300.7	MMBtu/hr	RFG	256.8	9.8		415	125679	27.8	213198	3314786
64	crude vacuum heater	43	heater	94.5	MMBtu/hr	RFG	170	6.1		336	36500	80.8	213176	3314754
64	CFHT charge	44	heater	55.2	MMBtu/hr	RFG	170	6.3		277	24500	12	213242	3314844
64	FCCU charge	45	heater	56.2	MMBtu/hr	RFG	150	4.9		308	20507	18.1	213195	3315256
64	FCCU regenerator	47	heater	3.79	MMBtu/hr	NG	242	8.33		140	131150	39.5	213123	3315114
64	FCCU air heater	48	heater	100	MMBtu/hr	RFG	242			140	97520		213123	3315114
64	alky isostripper	49	heater	108	MMBtu/hr	RFG	190	6.3		407	46165	24.7	213114	3315196
64	coker charge	60	heater	175	MMBtu/hr	RFG	200	5.63		350	63262	42.4	212480	3314826
64	CHFT fract. charge	61	heater	37.6	MMBtu/hr	RFG	170	6.3		336	18000	9.6	213251	3314866
64	crude heaters	65	heater	96.4	MMBtu/hr	RFG	170	6.08		400	39800	22.5	213132	3314396
64	isom charge	17a	heater	25	MMBtu/hr	RFG	52	2.8		639	12705	34.4	212993	3314958
64	isom charge	17b	heater	25	MMBtu/hr	RFG	52	2.8		670	13128	39.8	212995	3314954
64	reformer charge	19a	heater	164	MMBtu/hr	RFG	150	10		535	77048	16.4	213013	3314982
64	reformer charge	19b	heater	164	MMBtu/hr	RFG	150	10		535	77048	16.4	213007	3314982
64	hydrocracker charge	23c	heater	34.3	MMBtu/hr	RFG	130	3.42		840	18420	33.9	213073	3315002
64	Detol reboiler	85a	heater	85.9	MMBtu/hr	RFG	124.5	7.7		530	84000	30	213408	3314893
64	f-103 reactor charge	85b	heater	43.7	MMBtu/hr	RFG	124.5	7.7		530	84000	30	213408	3314893
64	f-103 reactor charge	85c	heater	22.8	MMBtu/hr	RFG	124.5	7.7		530	84000	30	213408	3314893
64	hydrocracker charge		heater	34.2	MMBtu/hr	RFG	130	3.4		970	20000	36.5	213073	3315002
64	loading-truck rack	1-96	loading - truck	2.10E+02	MMgal/yr		10	0.21		77	160	77	214149	3314654
64	loading-product	LD	loading product	2.00E+02	MMgal/yr								212800	3314800
64	reboiler	7	reboiler	26	MMBtu/hr	RFG	66	4.5		832	16272	17.1	213078	3314762
64	reboiler	9	reboiler	85	MMBtu/hr	RFG	86.5	5.8		729	36837	23.2	213030	3314748
64	rerun tower	12	reboiler	30.7	MMBtu/hr	RFG	41	3.33		551	22739	44.3	212972	3314928
64	prefractionator	16	reboiler	36.6	MMBtu/hr	RFG	103	4.6		527	16050	16.1	213065	3314787
64	pretreater	22	reboiler	24	MMBtu/hr	RFG	43	3.9		628	12796	17.9	213030	3315067
64	HDS stripper	40	reboiler	47.5	MMBtu/hr	RFG	150	5		528	26265	22.3	212864	3314896
64	hydrocarbon stab	25a	reboiler	44	MMBtu/hr	RFG	55.4	4.2		710	25950	31.2	213074	3314018
64	hydrocarbon stab	25a	reboiler	44	MMBtu/hr	RFG	55.4	4.2		710	25950	31.2	213069	3315017
64	reboiler	8a	reboiler	67.35	MMBtu/hr	RFG	66	4.5		832	16272	17.1	213078	3314762
64	reboiler	8b	reboiler	67.35	MMBtu/hr	RFG	105	4.4		1007	46211	50.7	213080	3314724
64	catalytic reformer	73	Regeneration vent #1	3.00E+01	MMCF/day		158	0.5		844	614	52.1	213198	3314786
64	catalytic reformer	74	Regeneration vent #3	3.00E+01	MMCF/day		158	0.5		844	614	52.1	213013	3314982

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
64	wastewater treatment	1S	sump 1-wwt										212864	3314896
64	wastewater treatment	2S	sump 2-wwt										212864	3314896
64	wastewater treatment	3S	sump 3-wwt										212864	3314896
64	wastewater treatment	AS	sump-alky										212864	3314896
64	tanks	CF-TK	tanks-coker feed	1.84E+02	MMgal/yr								212660	3314954
64	tanks	C-TK	tanks-crude oil	3.66E+03	MMgal/yr								212941	3314719
64	tanks	2-96	tanks-diesel/gasoline	1.20E+02	MMgal/yr								213607	3314859
64	tanks	FD-TK	tanks-distillate (finishes)	1.10E+03	MMgal/yr								214492	3314602
64	tanks	GO-TK	tanks-FCC feed (gas oil)	1.06E+03	MMgal/yr								212878	3315372
64	tanks	FG-TK	tanks-gasoline	2.06E+03	MMgal/yr								214290	3314733
64	tanks	GA-TK	tanks-gasoline additives	1.34E+00	MMgal/yr								213130	3315284
64	tanks	UG-TK	tanks-gasoline(unfinished)	1.64E+03	MMgal/yr								213088	3315093
64	tanks	MX-TK	tanks-mixed xylene	2.10E+02	MMgal/yr								212729	3314756
64	tanks	ME-TK	tanks-MTBE	3.09E+02	MMgal/yr								213132	3315205
64	tanks	N-TK	tanks-naphtha	4.56E+02	MMgal/yr								212743	3315089
64	tanks	OX-TK	tanks-o-xylene	2.46E+02	MMgal/yr								213134	3314740
64	tanks	PX-TK	tanks-p-xylene	4.97E+01	MMgal/yr								213142	3314733
64	tanks	SO-TK	tanks-slop oil	1.88E+01	MMgal/yr								212738	3315011
64	tanks	T-TK	tanks-toluene	6.11E+01	MMgal/yr								212696	3314911
64	tanks	UD-TK	tanks-unfinished distillate	5.06E+02	MMgal/yr								212740	3314787
64	wastewater treatment	WW-TK	tanks-wastewater	684	MMgal/yr								213000	3314000
64	sru thermal oxidizer	46	thermal oxidizer	46.7	MMBtu/hr	RFG	150	5.25		565	17700	13.4	212842	3314974
64	api separator thermal oxidizer	86	thermal oxidizer	3.1	MMBtu/hr	NG	100	1		1600	1850	39.3	212854	3314724
65	boiler - steam	1-74a	boiler - steam	100	MMBtu/hr	RFG	150	8		321	31510	10.5	731777	3327938
65	boiler - steam	1-74B	boiler - steam	100	MMBtu/hr	RFG	150	8		321	31510	10.5	731777	3327938
65	cooling tower	123-91	cooling tower	1.50E+04	gal/min								732534	3327854
65	marine vessel loading	107-90	flare	30	MMBtu/hr	NG	48		300	2400	1.99E+06	110	731675	3326600
65	flare	83-74	flare-north	1.8	MMBtu/hr	NG	200	3		2000	1410	4.5	732164	3327604
65	flare	69-74	flare-south	16.1	MMBtu/hr	NG	200	3		2000	1910	4.5	732164	3327604
65	crude unit	unit 10	fugitives										731534	3327854
65	naphtha hydrotreater	unit 11	fugitives										731534	3327854
65	platformer	unit 12	fugitives										731534	3327854
65	hydrotreater distillate	unit 14	fugitives										731534	3327854
65	heavy gas oil	unit 15	fugitives										731534	3327854
65	Merox unit	unit 16	fugitives										731534	3327854

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
65	Merox-light stream	unit 18	fugitives										731534	3327854
65	saturated gas plant	unit 22	fugitives										731534	3327854
65	FCCU	unit 25	fugitives										731534	3327854
65	butane isomarization	unit 28	fugitives										731534	3327854
65	intermediate product	unit 41	fugitives										731534	3327854
65	fuel gas	unit 43	fugitives										731534	3327854
65	marine vessel loading	unit 50	fugitives										731534	3327854
65	flare knock out drum	unit 59	fugitives										731534	3327854
65	pipeline	unit 63	fugitives										731534	3327854
65	loading truck rack	unit 65	fugitives										731534	3327854
65	blending facilities	unit 67	fugitives										731534	3327854
65	fugitives	unit 7	fugitives										731534	3327854
65	hydrotreater	unit 8	fugitives										731534	3327854
65	penex dip	unit 9	fugitives										731534	3327854
65	wastewater treatment	60-74	fugitives-wwt										731795	3327656
65	alkylation	85-74	heater-alkylation reboiler	269	MMBtu/hr	RFG	183.5	9		320	80400	21.1	732164	3327604
65	boiler - steam	111-91	heater-boiler	350	MMBtu/hr	NG	205	12.9		530	155954	20	732164	3327604
65	crude oil	2-74	heater-crude	278	MMBtu/hr	RFG	200	12.25		350	127600	18.4	732164	3327604
65	crude oil	3-74	heater-crude	278	MMBtu/hr	RFG	200	12.25		350	127600	18.4	732164	3327604
65	deasphalting	102-90	heater-deasphalting	221	MMBtu/hr	RFG	150	7.72		400	56100	20	732164	3327604
65	FCCU	84-74	heater-FCCU charge	220	MMBtu/hr	RFG							732164	3327604
65	heavy gas oil	12-74	heater-heavy gas oil charge	123.5	MMBtu/hr	RFG	150	7.96		750	70400	23.6	732164	3327604
65	heavy gas oil	13-74	heater-heavy gas oil reboile	71.1	MMBtu/hr	RFG	150	7.96		750	70400	23.6	732164	3327604
65	light gas oil	10-74	heater-light gas oil charge	77.3	MMBtu/hr	RFG	150	5.71		750	34700	222	732164	3327604
65	light gas oil	11-74	heater-light gas oil reboiler	68	MMBtu/hr	RFG	172	5.21		730	27400	21.4	732164	3327604
65	LSR HTU	100-85	heater-LSR HTU charge	17.2	MMBtu/hr	RFG	113	1.75		643	5170	35.8	732164	3327604
65	LSR HTU	101-85	heater-LSR HTU reboiler	15	MMBtu/hr	RFG	113	2.17		408	5153	23.2	732164	3327604
65	naphtha charge	6-74	heater-naphtha charge	52.8	MMBtu/hr	RFG	192	5.5		760	28600	18.8	732164	3327620
65	naphtha stripper	7-74	heater-naphtha stripper	61.4	MMBtu/hr	RFG	192	5.75		670	39500	25.3	732164	3327604
65	platformer	89-74	heater-platformer	209	MMBtu/hr	RFG	200	9		500	49500	13	732164	3327604
65	platformer	8-74	heater-platformer charge	408	MMBtu/hr	RFG	200	10.75		610	241600	44.4	732164	3327604
65	platformer	9-74	heater-platformer reboiler	60.8	MMBtu/hr	RFG	200	4.75		630	30000	28.2	732164	3327604
65	saturated gas plant	92-80	heater-saturated gas	72.5	MMBtu/hr	RFG	156	6.5		600	33300	16.75	732164	3327604
65	thermal drying	124-1-91	heater-thermal drying	4	MMBtu/hr	NG	25	0.33		75	200	38	732164	3327604
65	crude still	4-74	heater-vacuum still	138	MMBtu/hr	RFG	200	7.63		850	70800	25.9	732164	3327604

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
65	crude still	5-74	heater-vacuum still	138	MMBtu/hr	RFG	200	7.63		850	70800	25.9	732164	3327604
65	land treatment	128-93	landtreatment	10	acres								731534	3327854
65	marine vessel loading	134-96	loading-uncontrolled										731534	3327854
65	tanks	AL-TK	tank-alkylate (2)										731534	3327854
65	tanks	CT-TK	tank-cat. gas isom. (2)										731534	3327854
65	tanks	DA-TK	tank-deashpalted oil (1)										731534	3327854
65	tanks	GO_TK	tank-gas oil (1)										731534	3327854
65	tanks	hvynp-tk	tank-heavy FCCU naphtha(1)										731534	3327854
65	tanks	SHVO-TK	tank-HVGO feed (1)										731534	3327854
65	tanks	NP-TK	tank-naphtha feed										731534	3327854
65	tanks	NG-TK	tank-NG condensate (2)										731534	3327854
65	tanks	PL-TK	tank-platformate (2)										731534	3327854
65	tanks	RF-TK	tank-raffinate swing (3)										731534	3327854
65	tanks	CR-TK	tanks-crude oil (8)										731534	3327854
65	tanks	FO-TK	tanks-fuel oil (11)										731534	3327854
65	tanks	GS-TK	tanks-gasoline (6)										731534	3327854
65	tanks	SL-TK	tank-slop oil (2)										731534	3327854
65	tanks	SG-Tk	tank-sour gas oil (2)										731534	3327854
65	tanks	SN-TK	tank-sour naphtha (2)										731534	3327854
65	wastewater treatment	124-10-91	tank-wwt	21000	gal								731534	3327854
65	wastewater treatment	124-11-91	tank-wwt	3780	gal								731534	3327854
65	wastewater treatment	124-12-91	tank-wwt	3780	gal								731534	3327854
65	wastewater treatment	124-3-91	tank-wwt	21000	gal								731534	3327854
65	thermal oxidizer	14-74	thermal oxidizer 1	52.4	MMBtu/hr	NG	200	5.71		1200	63000	41	732164	3327604
65	thermal oxidizer	70-74	thermal oxidizer 2	30	MMBtu/hr	NG	200	5.71		1200	63000	41	732164	3327604
65	thermal oxidizer	?-74	thermal oxidizer 3		MMBtu/hr	NG	200	5.71		1200	63000	41	732164	3327604
65	FCCU	86-74	vent-FCCU regenerator				220	8		140	243595	80.7	732164	3327604
65	platformer	62-74	vent-regenerator				50	0.5		900	192	16	731534	3327854
67	coker	2-84	flare-coker				225	3.72		1832		20	750831	3321568
67	utilities	3-84	flare-east				208	5.69		1832		65.62	750563	3321529
67	fractionation plant	3-93	flare-fractionation				50	5.48		1832		20	750368	3323159
67	GO	1-90	flare-GO-1				225	35.48		1832		20	750321	3321440
67	west OPS	9-84	flare-ground				52	17.07		1832		20	750381	3321814
67	HCU	4-84	flare-HCU				225	14.55		1832		20	750603	3321315
67	marine vessel loading	5-89	flare-marine vapor recovery	8214	MMscf/yr		65	11.9		1832		65.62	750164	3320825

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
67	west OPS	5-84	flare-west				300	17.52		1832		20	750384	3321839
67	distribution	3003-95	fugitives-distribution				3						750586	3329930
67	marine vessel loading	3012-95	fugitives-marine vapor recovery				3						750148	3320816
67	tank	1006-95	tank	91000	bbl/yr		7.5						750102	3321882
67	tank	1007-95	tank	91000	bbl/yr		7.5						750114	3321879
67	tank	1071-95	tank	17	MMbbl/yr		30.33						749976	3321244
67	tank	1072-95	tank	17	MMbbl/yr		29.33						749958	3321189
67	tank	1204-95	tank-external float	4.1	MMbbl/yr		40	45					750333	3322285
67	tank	1207-95	tank-external float	0.64	MMbbl/yr		30.33	114.58					749872	3321258
67	tank	1225-95	tank-external float	28.1	MMbbl/yr		40	160					750484	3322593
67	tank	1226-95	tank-external float	28.1	MMbbl/yr		40	160					750575	3322495
67	tank	1227-95	tank-external float	28.1	MMbbl/yr		40.25	120					750435	3322425
67	tank	1228-95	tank-external float	28.1	MMbbl/yr		40.25	120					750538	3322399
67	tank	1229-95	tank-external float	28.1	MMbbl/yr		40.25	125					750457	3322512
67	tank	1231-95	tank-external float	14.4	MMbbl/yr		40	45					750427	3322677
67	tank	1232-95	tank-external float	14.4	MMbbl/yr		40	45					750429	3322643
67	tank	1233-95	tank-external float	24.2	MMbbl/yr		40	164					750696	3322874
67	tank	1241-95	tank-external float	30.4	MMbbl/yr		40.25	140					750321	3322179
67	tank	1242-95	tank-external float	30.4	MMbbl/yr		40	140					750460	3322102
67	tank	1246-95	tank-external float	308	MMgal/yr		40	140					750791	3322924
67	tank	1247-95	tank-external float	308	MMgal/yr		40	180					750832	3323090
67	tank	1248-95	tank-external float	9.9	MMbbl/yr		40	100					750383	3322134
67	tank	1253-95	tank-external float	28.1	MMbbl/yr		40	140					750531	3322993
67	tank	1254-95	tank-external float	28.1	MMbbl/yr		40	140					750617	3322971
67	tank	1255-95	tank-external float	28.1	MMbbl/yr		40	140					750554	3323075
67	tank	1265-95	tank-external float	2.2	MMbbl/yr		40	45					750403	3322236
67	crude tank group	5002-97	tank-external float	10	MMbbl/yr									
67	tank	1022-95	tank-fixed roof	120	MMgal/yr		38.5						750561	3323162
67	tank	1023-95	tank-fixed roof	120	MMgal/yr		38.5						750659	3323137
67	tank	1044-95	tank-fixed roof	140	MMgal/yr		39						750715	3321918
67	tank	1045-95	tank-fixed roof	140	MMgal/yr		37						750673	3321998
67	tank	1073-95	tank-fixed roof	1.9	MMbbl/yr		40			130			750123	3321112
67	tank	1074-95	tank-fixed roof	8.6	MMbbl/yr		40			130			750197	3321016
67	tank	1075-95	tank-fixed roof	8.6	MMbbl/yr		40			130			750118	3321036
67	tank	1024-95	tank-gas oil-fixed roof	120	MMgal/yr		38.5						750762	3323111

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
67	tank	1025-95	tank-gas oil-fixed roof	120	MMgal/yr		38.5						750784	3323196
67	tank	1026-95	tank-gas oil-fixed roof	120	MMgal/yr		38.5						750681	3323223
67	tank	1027-95	tank-gas oil-fixed roof	120	MMgal/yr		38.5						750583	3323247
67	tank	1028-95	tank-gas oil-fixed roof	120	MMgal/yr		39						750901	3323384
67	tank	1029-95	tank-gas oil-fixed roof	120	MMgal/yr		39						750919	3323458
67	tank	1030-95	tank-gas oil-fixed roof	120	MMgal/yr		39						750825	3323406
67	tank	1036-95	tank-gas oil-fixed roof	100	MMgal/yr		39						750811	3323303
67	tank	1224-95	tank-internal float	12.4	MMbbl/yr		39.67	100					750547	3321961
67	tank	1230-95	tank-internal float	28.1	MMbbl/yr		40	110					750617	3322053
67	tank	1263-95	tank-internal float	35	MMbbl/yr		40	120					750316	3321135
67	tank	1041-95	tank-kerosene-fixed roof	150	MMgal/yr		28						749895	3321362
67	tank	1042-95	tank-kerosene-fixed roof	150	MMgal/yr		28						749995	3321321
67	tank	1043-95	tank-kerosene-fixed roof	690	MMgal/yr		28						750285	3321814
67	tank	1047-95	tank-kerosene-fixed roof	140	MMgal/yr		39						750589	3322277
67	tank	1048-95	tank-kerosene-fixed roof	140	MMgal/yr		40						750643	3322456
67	wharf loading - uncontrolled	3307-95	wharf loading - uncontrolle	652	MMgal/yr		15						749875	3320770
68	alky reboiler	1-77	alky reboiler	164	MMBtu/hr	RFG	200	8.83		416	16195	5.6	215946	3314755
68	boiler - steam	10-72	boiler	82	MMBtu/hr	RFG	31	4		1100	21800	29	215864	3314573
68	boiler - steam	2-80	boiler	101	MMBtu/hr	RFG	80	5		325	21023	17.8	215846	3314562
68	boiler - steam	8-72	boiler	40	MMBtu/hr	RFG	25	3.5		1100	7300	12.6	215858	3314557
68	hydrobon charge heater	14-72	charge heater	46.9	MMBtu/hr	RFG	126	4.7		725	13525	14.4	215983	3314682
68	platformer	17-72	charge heater	200	MMBtu/hr	RFG	180	7.5		580	44356	16.9	215945	3314679
68	platformer	18-72	charge heater	128	MMBtu/hr	RFG	185	7.5		560	44356	16.9	215949	3314688
68	DHT	5-73	charge heater	43.4	MMBtu/hr	RFG	48	4.2		1100	11728	14	215975	3314581
68	compressors (8)	1-88	compressors (8)	1440	MMBtu/hr	NG	35	0.75		750	4000	151	215935	3314595
68	crude heaters	12-72a	crude heaters	377.6	MMBtu/hr	RFG	170	10.3		350	115000	23	215989	3314669
68	flare	1-94	flare	0.687	MMBtu/hr	NG	40	5		1500	11.5	0.01	216070	3315310
68	marine vessel loading	1-92	flare-marine loading	3.60E-01	MMBtu/hr	NG	88	0.82		538		65.6	215574	3314093
68	flare	20-72	flare-North	7.50E+00	MMBtu/hr	NG	200	0.32		1832	35424	65.6	216269	3314771
68	flare	3-77	flare-South	7.50E+00	MMBtu/hr	NG	200	0.32		1832	35424	65.6	216252	3314708
68	fugitives	fugitives	fugitives -leaks										215916	3314637
68	fractionator	2-92	heater	200.6	MMBtu/hr	RFG	150	9		350	56874	14.9	216094	3314569
68	loading	5-88	loading-river dock	1.48E+07	bpy								216076	3313937
68	FCCU	5-72	preheater	32.6	MMBtu/hr	RFG	41.2	3.5		1100	11839	20.5	215852	3314581
68	hydrobon reboiler	15-72	reboiler	44.5	MMBtu/hr	RFG	125	4.5		625	12384	13.2	215852	3314581

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
68	hydrobon reboiler	16-72	reboiler	50	MMBtu/hr	RFG	125	4.5		500	11000	11.7	215979	3314671
68	platformer	19-72	reboiler	50	MMBtu/hr	RFG	125	3.7		510	4091	6.3	215981	3314677
68	rose heater	1-80	rose heater	135	MMBtu/hr	RFG	110	8		350	41600	10.8	216076	3314621
68	sulfur recovery incinerator	1-93	sulfur recovery incinerator	16.5	MMBtu/hr	RFG	200	2		500	16400	87	215966	3314628
68	sulfur recovery incinerator	6-73	sulfur recovery incinerator	4	MMBtu/hr	RFG	180	4.5		1053	16973	17.8	216035	3314577
68	tank	80-16	tank-MTBE	1.60E+06	bpy		32						216486	3314972
68	tanks	cap-crude	tanks-crude oil (7)	4.00E+07	bpy		32	215					216388	3314760
68	tanks	cap-gasoline	tanks-gasoline (7)	2.34E+07	bpy		32	215					216528	3315036
68	tanks	cap-heavy oil	tanks-heavy oil (8)	5.04E+07	bpy		40		0.545				215943	3314946
68	tanks	cap-mid	tanks-middle distillate (6)	1.70E+07	bpy		40		1091				216347	3315108
68	tanks	cap-naphtha	tanks-naphtha (2)	8.60E+06	bpy		40		48				216158	3314791
68	tanks	25-2	tank-sourwater	4.30E+05	bpy		32						215935	3315007
68	tanks	cap-slop oil	tanks-slop oil (2)	1.90E+05	gal/yr		16		0.349				216130	3315206
68	wastewater treatment	150-2	tank-wwt	4.97E+03	bpy		40		1571				216219	3315222
68	wastewater treatment	80-14	tank-wwt	7.20E+08	gal/yr		40	120					216222	3315128
68	wastewater treatment	80-17	tank-wwt	2.63E+03	bpy		40	120					216188	3315240
68	vacuum heater	1-76	vacuum heaters	196	MMBtu/hr	RFG	110	7.5		300	53000	20	216061	3314629
68	FCCU	2-97	vent-FCC	2.97E+04	lb/hr coke		180	16.9		600	180556	80.5	215868	3314814
68	platformer	21-72	vent-regenerator				80	3		100	1.7	0.58	215958	3314669
70	CO boiler	b2001	boiler	146.3	MM Btu/hr	RFG	200	3.5		280	80079	130	425392	3592365
70		i-a	boiler	175.4	MM Btu/hr	RFG	40	5		570	70450	59.8	425333	3592583
70		i-b	boiler	175.4	MM Btu/hr	RFG	40	5		570	70450	59.8	425333	3592573
70	boiler - steam	iv-f	boiler	44.3	MM Btu/hr	RFG	75	3.5		430	15359	26.6	425353	3592583
70	boiler - steam	iv-g	boiler	44.3	MM Btu/hr	RFG	75	3.5		430	15359	26.6	425353	3592573
70	catalytic dewaxing	viii-a	compressor	7.50E+00	MM Btu/hr	RFG	15	0.5		650	3500	297	425538	3592525
70	catalytic dewaxing	viii-b	compressor	3.50E+02	bhp	NG	15	0.5		650	3500	297	425538	3592519
70	catalytic dewaxing	viii-c	compressor	3.50E+02	bhp	NG	15	0.5		650	3500	297	425538	3592513
70	catalytic dewaxing	viii-d	compressor	3.50E+02	bhp	NG	15	0.5		650	3500	297	425538	3592497
70	catalytic dewaxing	viii-e	compressor	3.50E+02	bhp	NG	15	0.5		650	3500	297	425538	3592491
70	platformer	viii-f	compressor	4.40E+02	bhp	NG	30	0.67		650	4400	210	425486	3592252
70	platformer	viii-g	compressor	4.40E+02	bhp	NG	30	0.67		650	4400	210	425486	3592260
70	platformer	viii-h	compressor	4.40E+02	bhp	NG	30	0.67		650	4400	210	425486	3592258
70	platformer	viii-i	compressor	4.40E+02	bhp	NG	30	0.67		650	4400	210	425486	3592268
70	platformer	viii-j	compressor	4.40E+02	bhp	NG	30	0.67		650	4400	210	425518	3592241
70	platformer	viii-k	compressor	4.40E+02	bhp	NG	30	0.67		650	4400	210	425517	3592241

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
70	tank	t-146	cone roof tank-MEK	8400	gal		18	10					425836	3592453
70	tank	t-147	cone roof tank-MEK/toluen	101000	gal		36	22					425845	3592453
70	tank	t-149	cone roof tank-MEK/toluen	100800	gal		36	22					425845	3592441
70	tank	t-301	cone roof tank-MEK/toluen	48000	gal		24	18.5					425793	3592540
70	tank	t-402	cone roof tank-MEK/toluen	17000	gal		20	12					425793	3592558
70	tank	t-503	cone roof tank-MEK/toluen	38000	gal		20	18.5					425793	3592552
70	tank	t-504	cone roof tank-MEK/toluen	17000	gal		20	12					425793	3592546
70	tank	t-145	cone roof tank-toluene	8400	gal		18	10					425831	3592453
70	Lubes	ctlub	cooling tower										425691	3592444
70	Marley	ctmar	cooling tower										425222	3592588
70	Udex	ctudx	cooling tower										425406	3592580
70	wastewater treatment	to2002	flare	1.95E+00	MM Btu/hr	NG	45	3		1600	8900	21	425429	3592074
70	main refinery flare	v-g	flare	3.11E+01	MM Btu/hr	RFG	198	2		1000	17720	94	425587	3592116
70	secondary refinery flare	v-h	flare	7.79E+00	MM Btu/hr	RFG	100	1.67		1000	4436	33.7	425683	3592373
70	gasoline bulk terminal	vi-ia	flare	1.10E-01	MM Btu/hr	RFG	45	8		1800	106827	35.4	425353	3592602
70	East process area	fuep	fugitives										425672	3592532
70	tank farm/CCU area	futfccu	fugitives										425489	3592111
70	truck loading	futl	fugitives										425356	3592637
70	West process area	fuwp	fugitives										425349	3592541
70	wastewater treatment-drains&sepa	vi-a	fugitives										425550	3592200
70	naphtha	ii-e	heater	27.5	MM Btu/hr	RFG	88	2.7		630	10000	28.9	425264	3592549
70	naphtha	ii-f	heater	12.5	MM Btu/hr	RFG	85.6	2.7		495	4637	13.4	425265	3592552
70	platformer	ii-i	heater	47.6	MM Btu/hr	RFG	50.5	4.5		700	21534	22.6	425272	3592553
70	crude still	iii-a	heater	33.3	MM Btu/hr	RFG	101	4.2		700	15078	18.5	425553	3592557
70	asphalt furnace	iii-b-a	heater	4.7	MM Btu/hr	RFG	45	2.5		1000	1980	6.7	425597	3592492
70	asphalt furnace	iii-b-b	heater	0.86	MM Btu/hr	RFG	24	1.5		1000	490	4.6	425597	3592489
70	NMP unit	iii-c	heater	21.4	MM Btu/hr	RFG	81	2.75		1000	12208	34.3	425599	3592532
70	raffinate furnace	iii-d	heater	20.9	MM Btu/hr	RFG	75	3		560	8318	19.6	425599	3592541
70	crude charge	iii-f	heater	101.5	MM Btu/hr	RFG	117	6		760	48294	28.5	425476	3592493
70	crude charge	iii-g	heater	18.9	MM Btu/hr	RFG	55	4.5		700	8559	9	425476	3592501
70	naphtha reboiler	iii-h	heater	10.9	MM Btu/hr	RFG	33	2.75		575	3613	10.1	425410	3592496
70	lube oil hydrotreater	iii-i	heater	8.6	MM Btu/hr	RFG	45	3.6		630	3673	6.1	425674	3592523
70	lube oil hydrotreater	iii-m	heater	8	MM Btu/hr	RFG	80	2.5		485	2956	10	425679	3592523
70	platformer	ii-k	heater	36.1	MM Btu/hr	RFG	97	4		510	13657	18.1	425252	3592561
70	platformer	ii-s	heater	34.2	MM Btu/hr	RFG	80	4.7		850	17473	16.7	425240	3592561

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
70	crude	ii-v	heater	7.2	MM Btu/hr	RFG	52	2		605	3003	15.9	425411	3592517
70	crude vacuum heater	iv-a	heater	42.1	MM Btu/hr	RFG	75	4.5		540	16403	17.2	425453	3592422
70	NMP extraction	iv-b	heater	17.2	MM Btu/hr	RFG	75	3.25		590	7060	14.2	425599	3592555
70	MEK dewaxing	iv-c	heater	29.2	MM Btu/hr	RFG	75	4.5		530	11270	11.8	425727	3592498
70	MEK dewaxing	iv-d	heater	21.2	MM Btu/hr	RFG	75	4.25		535	8223	9.7	425751	3592499
70	wax hydrofinisher	iv-e	heater	20.9	MM Btu/hr	RFG	55	2		635	747	4	425788	3592493
70	hydrotreater charge	v-b	heater	1.16E+01	MM Btu/hr	RFG	115	2.2		700	5252	23.7	425838	3592543
70	hydrotreater still	v-c	heater	8.60E+00	MM Btu/hr	RFG	115	2.8		700	9157	24.3	425805	3592492
70	hydrotreater still	v-d	heater	8.05E+00	MM Btu/hr	RFG	115	1.9		700	3642	21	425830	3592492
70	hydrogen reformer	v-e-a	heater	8.00E+01	MM Btu/hr	RFG	115	4.42		700	36192	86.9	425789	3592592
70	hydrogen reformer	v-e-b	heater	8.00E+01	MM Btu/hr	RFG	115	4.42		700	36192	86.9	425789	3592492
70		v-e-c	heater	1.70E+01	MM Btu/hr	RFG	115	4.42		700	36192	86.9	425789	3592492
70	sulfur recovery incinerator	v-f	heater	6.30E+00	MM Btu/hr	RFG	175	2.5		1200	6283	59.3	425866	3592413
70	DDD reactor charge	v-i-b	heater	3.75E+01	MM Btu/hr	RFG	45	4.58		500	11107	11.3	425498	3592500
70	DDD light diesel	v-i-c	heater	1.65E+01	MM Btu/hr	RFG	45	3.58		800	6712	1101	425497	3592546
70	DDD reboiler	v-i-d	heater	1.71E+01	MM Btu/hr	RFG	38	2.5		820	3337	11.3	425498	3592495
70	DDD vacuum charge	v-i-e	heater	3.80E+00	MM Btu/hr	RFG	84.3	2.88		550	12645	32.4	425497	3592552
70	tank heater	vii-a	heater	7.50E+00	MM Btu/hr	RFG	54	0.83		600	1034	31.8	425682	3592275
70	tank heater	vii-c	heater	1.25E+01	MM Btu/hr	RFG	46	0.83		600	1034	31.9	425791	3592074
70	tank heater	vii-d	heater	1.24E+02	MM Btu/hr	RFG	46	0.83		600	1034	31.9	425751	3592085
70	tank heater	vii-e	heater	1.60E+00	MM Btu/hr	RFG	46	0.83		600	661	20.4	425753	3592252
70	residual	t-174	tank cone roof	1.00E+06	gal		40	67		175			425418	3592265
70	distillate tanks	t-47	tank cone roof distillate	2.10E+05	gal		30	35					425542	3592451
70	distillate tanks	t-48	tank cone roof distillate	2.10E+05	gal		30	35					425542	3592431
70	distillate tanks	t-52	tank cone roof distillate	2.30E+06	gal		31	114.7					425428	3591825
70	distillate tanks	t-72	tank cone roof distillate	4.20E+05	gal		35.6	45					425444	3592312
70	distillate tanks	t-73	tank cone roof distillate	4.20E+05	gal		35.6	45		80			425443	3592264
70	tank-gasoline	t-29	tank cone roof gasoline	210000	gal		30	35					425240	3592413
70	lube oil	t-64	tank cone roof lube oil	4.20E+05	gal		40	42.5					425174	3592267
70	tank slop oil	t-59	tank cone roof slop oil	2.52E+04	gal		10	20					425414	3592337
70	crude	t-175	tank floating roof crude	3.36E+06	gal		42.8	127					425142	3591971
70	crude	t-43	tank floating roof crude	3.36E+06	gal		40.5	117.2					425232	3592171
70	crude	t-44	tank floating roof crude	3.36E+06	gal		40.5	117.2					425230	3592043
70	crude	t-49	tank floating roof crude	2.30E+06	gal		30	114.6					425355	3592078
70	crude	t-60	tank floating roof crude	3.40E+06	gal		40	120					425605	3592359

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
70	crude	t-61	tank floating roof crude	3.40E+06	gal		40	120					425169	3592074
70	crude	t-77	tank floating roof crude	3.40E+06	gal		48	110					425291	3591983
70	distillate tanks	t-50	tank floating roof distillate	2.30E+06	gal		28	114.6					425352	3591924
70	tank	t-55	tank floating roof distillate	1.00E+06	gal		40	67					425448	3592192
70	distillate tanks	t-74	tank floating roof distillate	2.30E+06	gal		48	90					425449	3592000
70	distillate tanks	t-75	tank floating roof distillate	2.30E+06	gal		48	90					425521	3591906
70	tank-gasoline	t-26	tank floating roof gasoline	210000	gal		40	30					425281	3592413
70	tank-gasoline	t-27	tank floating roof gasoline	210000	gal		40	30					425280	3592374
70	tank-gasoline	t-30	tank floating roof gasoline	210000	gal		30	35					425201	3592414
70	tank-gasoline	t-32	tank floating roof gasoline	210000	gal		30	35					425161	3592415
70	tank-gasoline	t-53	tank floating roof gasoline	1.00E+06	gal		40	67					425213	3592241
70	tank-gasoline	t-56	tank floating roof gasoline	1.00E+06	gal		40	67					425510	3592191
70	tank-gasoline	t-57	tank floating roof gasoline	1.00E+06	gal		40	67					425213	3592307
70	tank-gasoline	t-58	tank floating roof gasoline	1.00E+06	gal		40	67					425253	3592306
70	tank-gasoline	t-67	tank floating roof gasoline	1.00E+06	gal		40	67					425343	3592162
70	tank-gasoline	t-68	tank floating roof gasoline	1.00E+06	gal		40	67					425394	3592162
70	tank-gasoline	t-76	tank floating roof gasoline	3.40E+06	gal		48	110					425531	3591795
70	tank	t-54	tank floating roof lube oil	1.00E+06	gal		40	67					425253	3592241
70	tank slop oil	t-69	tank floating roof slop oil	2.10E+05	gal		40	30					425393	3592339
70	tank	t-199	tank-cone roof distillate	3.80E+06	gal		40	130					425150	3591900
70	wastewater treatment	t-188	tank-open top wastewater st	228000	gal		16	49					425520	3592052
73	wastewater treatment	308-T-16/17	bio treatment	1.30E+09	gal/yr		23						212088	3286186
73	cooling tower	303-R-1	cooling tower	1.50E+05	gal/min								212014	3287443
73	wastewater treatment	308-R-1	cooling tower	1.50E+05	gal/min								212014	3287443
73	marine vessel loading	406-D-15	flare	64.9		NG	25	3		1600	53333	126	212593	3286725
73	marine vessel loading	406-D-16	flare	64.9		NG	25	3		1600	53333	126	212593	3286725
73	catalytic reforming	1391-FF	Fugitives										212132	3287232
73	aromatic extraction from reformat	1791-FF	Fugitives										212094	3287218
73	benzene-hydrodealkylation	1792-FF	Fugitives										212094	3287218
73	crude unit	191-FF	Fugitives										211930	3287303
73	naphfining	291-FF	Fugitives										211941	3287279
73	hydrotreater (diesel)	292-FF	Fugitives										211930	3287250
73	marine vessel loading	406E-FF	Fugitives										212094	3287218
73	marine vessel loading	406N-FF	Fugitives										212094	3287218
73	tank farm	412-A-FF	fugitives-nonSOCMI tank farm										212094	3287218

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
73	tank farm	412-FF	fugitives-SOCMI tank farm										212094	3287218
73	coker	100-H-1	Heater	10.8	MM Btu/hr	RFG	50	2		610	3757	19.9	211659	3286650
73	coker	100-H-2	Heater	10.2	MM Btu/hr	RFG	30	2.25		539	2792	11.7	211659	3286650
73	catalytic reforming	1391-H-1	Heater	180	MM Btu/hr	fuel gas	206	11.5		423	97000	15.6	211920	3287460
73	catalytic reforming	1391-H-2/3	Heater	268	MM Btu/hr	fuel gas	217	12.9		914	96374	12.3	211884	3287447
73	catalytic reforming	1391-H-4	Heater	134	MM Btu/hr	fuel gas	145	7.2		531	50399	20.8	211884	3287433
73	catalytic reforming	1391-H-5	Heater	7	MM Btu/hr	fuel gas				531	3242	4.9	211838	3287429
73	aromatic extraction from reformat	1791-H-1	Heater	74	MM Btu/hr	fuel gas	125	6.4		534	16739	8.6	212056	3287319
73	benzene-hydrodealkylation	1792-H-1	Heater	92.8	MM Btu/hr	fuel gas	148	7.5		534	36720	13.9	211944	3287341
73	naphfining	291-H-1	Heater	85.3	MM Btu/hr	fuel gas	130	6.3		619	18000	9.8	211960	3287285
73	naphfining	291-H-2	Heater	109	MM Btu/hr	fuel gas	127	6.3		515	22657	12	211941	3287279
73	hydrotreater (diesel)	292-H-1	Heater	25.7	MM Btu/hr	fuel gas	92	4		613	6056	8	211930	3287303
73	hydrotreater (diesel)	292-H-2	Heater	45.9	MM Btu/hr	fuel gas	121	5.3		615	11869	9.1	213032	3287254
73	crude unit	191-H-1	Heater (crude charge)	925	MM Btu/hr	fuel gas	209	15.4		379	294690	26.4	211973	3287182
73	crude unit	191-H-2	Heater (vacuum charge)	131	MM Btu/hr	fuel gas	209	8.5		702	51353	15	211982	3287169
73	crude unit	191-H-2	Heater (vacuum charge)	305	MM Btu/hr	fuel gas	209	9		349	68853	18	211968	3287168
73	sulfur recovery	591-D-21-X	incinerator	11.1	MM Btu/hr	fuel gas	150	1.8		1049			212017	3287525
73	landfarm	308-landfarm	landfarm										212014	3287443
73	marine vessel loading	406-N	Product dock loading										212040	3288550
73	marine vessel loading	406-X	Product dock loading										212156	3288047
73	catalytic reforming	1391-V-4	Regeneration vent										211920	3287460
73	wastewater treatment	308-T-11	skimmed oil tank										212177	3286141
73	THD charge tank	100-T-103	Tank				40	85					211934	3287301
73	tank farm	100-T-204	tank-alkylate	2.90E+08	gal/yr		40	200					211741	3287730
73	benzene prod	100-T-107	tank-benzene	3.80E+07	gal/yr		33.7	34					211742	3287302
73	benzene prod	100-T-108	tank-benzene	3.80E+07	gal/yr		33.7	34					211841	3287312
73	tank farm	100-T-400	tank-benzene	3.70E+08	gal/yr		42	140					211670	3288029
73	tank farm	100-T-310	tank-diesel	4.40E+08	gal/yr		40	200					211610	3288339
73	tank farm	100-T-311	tank-diesel	4.40E+08	gal/yr		40	200					211503	3288302
73	tank farm	100-T-312	tank-diesel	4.40E+08	gal/yr		40	173					211397	3288266
73	tank farm	100-T-313	tank-diesel	4.40E+08	gal/yr		40	189					211580	3288179
73	tank farm	100-T-350	tank-diesel	3.70E+09	gal/yr		40	100					211643	3287957
73	wastewater treatment	308-T-14	tank-equalization	1.30E+09	gal/yr								212199	3286178
73	crude storage	100-T-001	Tank-FR-crude	1.50E+09	gal/yr		40	200					211659	3286650
73	crude storage	100-T-002	Tank-FR-crude	1.50E+09	gal/yr		40	200					211704	3286521

TABLE A-7. SOURCE PARAMETERS FROM PERMIT APPLICATIONS

ID	Process	Source	Description	Throughput	Units	Fuel	ht (ft)	dia (ft)	ft^2	T (F)	cfm	ft/s	H (UTM)	V (UTM)
73	crude storage	100-T-003	Tank-FR-crude	6.10E+08	gal/yr		40	200					211749	3286390
73	crude storage	100-T-004	Tank-FR-crude	6.10E+08	gal/yr		40	200					211784	3286287
73	crude storage	100-T-005	Tank-FR-crude	6.10E+08	gal/yr		40	200					211834	3286143
73	crude storage	100-T-006	Tank-FR-crude	6.10E+08	gal/yr		40	200					211883	3286002
73	crude storage	100-T-007	Tank-FR-crude	6.10E+08	gal/yr		40	200					211923	3285884
73	Naphtha	100-T-104	Tank-FR-naphtha	6.80E+08	gal/yr		40	173					211920	3287209
73	Naphtha	100-T-105	Tank-FR-naphtha	6.80E+08	gal/yr		40	173					211799	3287172
73	tank farm	100-T-200	tank-gasoline	1.10E+08	gal/yr		40	200					211823	3287492
73	tank farm	100-T-202	tank-gasoline	2.90E+08	gal/yr		40	200					211777	3287624
73	tank farm	100-T-302	tank-gasoline	1.60E+09	gal/yr		40	145					211464	3288069
73	tank farm	100-T-303	tank-gasoline	3.10E+09	gal/yr		40	145					211439	3288144
73	tank farm	100-T-351	tank-gasoline	3.70E+09	gal/yr		40	100					211661	3287905
73	tank farm	100-T-211	tank-heavy FCC gasoline	5.90E+08	gal/yr		40	200					211647	3287540
73	tank farm	100-T-325	tank-heavy raffinate	1.50E+08	gal/yr		42	85					211674	3287844
73	tank farm	100-T-213	tank-heavy reformate	2.20E+08	gal/yr		40	140					211583	3287726
73	tank farm	100-T0212	tank-light FCC gasoline	5.90E+08	gal/yr		40	200					211617	3287626
73	tank farm	100-T-251	tank-light raffinate	3.20E+09	gal/yr		40	100					211695	3287975
73	Reformer	100-T-106	tank-light reformate	9.20E+07	gal/yr		40	128					211914	3287357
73	wastewater treatment	308-T-73	tank-neutralized caustic										212229	3286096
73	wastewater treatment	308-T-76	tank-neutralized caustic										212229	3286096
73	wastewater treatment	308-T-15A	tank-storm water	1.30E+09	gal/yr		48						212148	3286067
73	wastewater treatment	308-T-15B	tank-storm water	1.30E+09	gal/yr		48						212229	3286096
73	tank farm	100-T-113	tank-swing	6.70E+08	gal/yr		40	90					611637	3287249
73	tank farm	100-T-250	tank-swing	1.80E+08	gal/yr		40	100					211695	3287975
73	tank farm	100-T-326	tank-swing	1.80E+08	gal/yr		42	85					211712	3287857
73	tank farm	100-T-201	tank-xylene	3.10E+07	gal/yr		42	100					211854	3287551
73	tank farm	100-T-203	tank-xylene	3.10E+07	gal/yr		42	100					211805	3287693
73	wastewater treatment	308-W-43	thermal oxidizer-wwt	2.4	MM Btu/hr	fuel gas							212048	3286169
74	catalytic cracking	5-96	FCC vent				167	4		450	90478	120	619719	3377350

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzen	Trimethyl benzene
61	CVS area	3xxx3	cooling tower	0.01	0.03			0.03				
61	marine vessel loading	3ix34	flare	0.06	0.06	0.01		0.04				
61	marine vessel loading	3ix35	flare	0.10	0.09	0.03		0.14			0.01	
61	Lift station	3ix38	flare	0.08	0.13	0.03	0.01	0.16				
61	flare	3ix41	flare- S central CVS	1.25				0.11				
61	CVS area	3misc7	fugitives & wastewater	0.21	0.42	0.12		0.57				
61	fugitives	3misc6	fugitives-miscellaneous	13.00	9.66	12.21	6.58	5.21		0.38	2.29	
61	aromatics tanks	3ix24	tank-aromatics FR 13 tanks	9.54								
61	crude oil tanks	3ix14	tank-crude FR 20 tanks	0.22	0.18			1.70				
61	distillate tanks	3ix22	tank-distillate fixed-12 tanks							0.25		
61		3ix33	tank-garage 3 tanks	0.22	0.09	0.03	0.02	0.49				
61	gasoline tanks	3ix17	tank-gasoline FR 10 tanks	2.00	2.20	1.08		2.70			0.24	
61	gasoline tanks	3ix15	tank-gasoline FR 22 tanks	1.95	2.01	0.49	1.09	2.48			0.10	
61	gasoline tanks	3ix18	tank-gasoline FR 4 tanks	0.22	0.22	0.01	2.90	1.06				
61	heavy naphtha	3ix30	tank-heavy naphtha fixed 6 ta	6.93	9.37	6.71		37.30			1.46	
61	kerosene tanks	3ix21	tank-kerosene FR 11 tanks							0.14		
61	naphtha tanks	3ix16	tank-naphtha FR 4 tanks	0.09	0.29	0.10		0.52			0.02	
61		3ix42	tank-slop FR-7 tanks	0.55	0.60	0.30		0.74			0.07	
61	wastewater treatment	3ix37	wastewater treatment	4.37	3.13	3.66	0.39	1.16		0.52	0.45	
63	tank farm	tanks-cb	catch basin		0.22	0.30						
63	hydroprocessing	hydro-ct	cooling tower			0.12		0.38				
63	distillation-"pipestill"	psla-ct	cooling tower		0.13	0.25		0.32				0.14
63	Reformer	reform-ct	cooling tower	0.21	0.45	0.58		1.01			0.14	0.10
63	wastewater treatment	wcla-off	figitives-offsite	1.90	5.18	5.72	4.38			0.46	0.54	
63	light hydrocarbon recovery	c3st-fug	fugitives	0.11								
63	alkylation - light ends	vle-fug	fugitives	0.64	0.49	0.20	0.15	1.57				
63	lube, dewax, hydrofining	spec-fug	fugitives	0.28	1.51	0.60		0.27		0.34	0.16	0.38
63	docks complex	m-fug	fugitives	0.16	2.45	1.09		0.29		0.32	0.46	0.43
63	hydroprocessing	hydro-fug	fugitives	0.81	0.83	1.83		3.48		0.34	0.99	0.91
63	docks complex	docks-fug	fugitives	1.43	4.09	4.45		1.51		0.32	1.02	1.75
63	distillation-"pipestill"	psla-fug	fugitives	0.67	1.74	4.25		4.13		1.60	3.54	2.46
63	light oil finishing	lofu-fug	fugitives	0.91	7.33	9.45		1.85		0.72	2.50	3.47
63	wastewater treatment	wcla-fug	fugitives	12.03	9.31	4.99	17.90			0.90	0.55	
63	Reformer	reform-fug	fugitives	2.94	8.50	17.40		5.31		1.26	2.66	7.79
63	tank farm	tanks-fug	fugitives	4.98	21.70	19.20		7.03		2.86	5.17	6.45

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
63	docks complex	m-tanks	tanks	1.80	5.89	1.77		7.08			0.83	0.22
63	tank farm	ref-tanks	tanks	18.80	45.90	15.50	185.00	42.40		0.86	18.10	3.70
64	coker -API	1C	coker #1		1.78	3.82				0.13		
64	coker -API	2C	coker #2		1.79	3.82				0.13		0.31
64	loading -crude terminal	CTAPI	crude terminal		0.11	0.23				0.01		0.02
64	fugitives	FE	fugitives -leaks	15.82	25.16	66.00	0.56	5.35		0.79	4.75	5.35
64	loading-truck rack	1-96	loading - truck	0.01	0.38	0.76		0.08		0.02	0.01	0.06
64	loading-product	LD	loading product		19.04	17.74				0.04	0.34	1.51
64	wastewater treatment	1S	sump 1-wwt		0.08	0.18				0.01		0.01
64	wastewater treatment	2S	sump 2-wwt		0.19	0.42				0.01		0.03
64	wastewater treatment	3S	sump 3-wwt		0.10	0.21				0.01		0.02
64	wastewater treatment	AS	sump-alky		0.23	0.50				0.01		0.04
64	tanks	CF-TK	tanks-coker feed							0.15		
64	tanks	C-TK	tanks-crude oil	0.69	0.40	0.03		1.36			0.01	
64	tanks	2-96	tanks-diesel/gasoline	0.09	2.32	4.59		0.49		0.14	0.04	0.38
64	tanks	FD-TK	tanks-distillate (finishes)		0.19	0.40				0.01		0.03
64	tanks	GO-TK	tanks-FCC feed (gas oil)			0.96				0.01		0.07
64	tanks	FG-TK	tanks-gasoline	0.25	0.63	0.19		1.48			0.09	0.02
64	tanks	GA-TK	tanks-gasoline additives	0.02	0.02	0.02					0.02	
64	tanks	UG-TK	tanks-gasoline(unfinished)	0.15	0.38	0.11		1.07			0.06	0.01
64	tanks	MX-TK	tanks-mixed xylene		4.96	21.20					5.24	0.36
64	tanks	ME-TK	tanks-MTBE				0.88					
64	tanks	N-TK	tanks-naphtha	0.05	0.05	0.02		0.38				
64	tanks	OX-TK	tanks-o-xylene			1.62						
64	tanks	PX-TK	tanks-p-xylene			3.46						
64	tanks	SO-TK	tanks-slop oil	0.25		0.08						0.01
64	tanks	T-TK	tanks-toluene		31.34							
64	tanks	UD-TK	tanks-unfinished distillate		0.58	1.26				0.04		0.10
64	wastewater treatment	WW-TK	tanks-wastewater		2.13	4.58				0.14		0.01
65	marine vessel loading	107-90	flare	2.14	8.67	12.05		14.55			0.03	
65	flare	83-74	flare-north	0.01	0.02	0.01		0.09	0.01			
65	flare	69-74	flare-south	0.02	0.02	0.01		0.09	0.04			
65	Merox-light stream	unit 18	fugitives	0.01	0.00							
65	butane isomarization	unit 28	fugitives		0.01						0.01	
65	Merox unit	unit 16	fugitives	0.00	0.00	0.00		0.01				

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
65	fuel gas	unit 43	fugitives	0.04								
65	fugitives	unit 7	fugitives		0.02	0.02					0.02	
65	heavy gas oil	unit 15	fugitives	0.04	0.02						0.02	0.02
65	saturated gas plant	unit 22	fugitives		0.04	0.04					0.04	
65	intermediate product	unit 41	fugitives	0.01	0.06	0.06		0.04			0.02	0.01
65	flare knock out drum	unit 59	fugitives	0.08	0.04	0.04					0.04	
65	hydrotreater distillate	unit 14	fugitives	0.03	0.02	0.23					0.02	0.02
65	naphtha hydrotreater	unit 11	fugitives	0.03	0.11	0.06		0.17			0.02	0.00
65	loading truck rack	unit 65	fugitives	0.09	0.09	0.09					0.09	0.09
65	hydrotreater	unit 8	fugitives	0.00				0.41			0.18	0.18
65	blending facilities	unit 67	fugitives	0.15	0.15	0.15		0.13			0.15	0.15
65	marine vessel loading	unit 50	fugitives	0.27	0.13	0.13		0.26			0.13	0.13
65	FCCU	unit 25	fugitives	0.07	0.21	0.32		0.31			0.07	0.17
65	penex dip	unit 9	fugitives	0.00				0.62			0.26	0.26
65	platformer	unit 12	fugitives	0.23	0.33	0.18		0.58			0.03	0.03
65	crude unit	unit 10	fugitives	0.16	0.91	0.81		0.86			0.24	0.09
65	pipeline	unit 63	fugitives	0.79	2.00	1.70		1.55			0.39	
65	wastewater treatment	60-74	fugitives-wwt	3.52	2.65	2.13		0.54			0.40	
65	land treatment	128-93	landtreatment		0.16	0.10		0.26				
65	marine vessel loading	134-96	loading-uncontrolled		0.06	0.18		0.02				
65	tanks	AL-TK	tank-alkylate (2)			0.01					0.00	
65	tanks	CT-TK	tank-cat. gas isom. (2)	0.04	0.12	0.19		0.05		0.06	0.04	0.10
65	tanks	DA-TK	tank-deashpalted oil (1)	0.01	0.04	0.04				0.01	0.01	
65	tanks	GO_TK	tank-gas oil (1)	0.98	4.15	3.56				0.52	0.75	
65	tanks	hvynp-tk	tank-heavy FCCU naphtha(1)		0.00	0.01		0.00			0.00	0.00
65	tanks	SHVO-TK	tank-HVGO feed (1)	0.02	0.08	0.07				0.01	0.02	
65	tanks	NP-TK	tank-naphtha feed	0.01	0.03	0.04		0.02			0.01	
65	tanks	NG-TK	tank-NG condensate (2)	0.10	0.04	0.02		0.59			0.00	
65	tanks	PL-TK	tank-platformate (2)	0.14	0.40	0.40				0.04	0.09	
65	tanks	RF-TK	tank-raffinate swing (3)	0.10	0.03	0.04		0.57		0.00	0.00	
65	tanks	CR-TK	tanks-crude oil (8)	0.03	0.09			0.90				0.11
65	tanks	FO-TK	tanks-fuel oil (11)		2.06	2.60		8.60		0.06	0.12	
65	tanks	GS-TK	tanks-gasoline (6)	0.23	0.29	0.27	2.97	0.10		0.02	0.04	0.07
65	tanks	SL-TK	tank-slop oil (2)	0.10	0.18	0.17					0.03	0.02
65	tanks	SG-Tk	tank-sour gas oil (2)	0.02	0.09	0.07				0.01		

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
65	tanks	SN-TK	tank-sour naphtha (2)	0.05	0.02	0.03		0.03		0.00	0.01	0.00
65	wastewater treatment	124-3-91	tank-wwt	0.01	0.00			0.01				
65	wastewater treatment	124-12-91	tank-wwt	0.01	0.00			0.01				
65	wastewater treatment	124-11-91	tank-wwt	0.02	0.01			0.04				
65	wastewater treatment	124-10-91	tank-wwt	0.05	0.03			0.01				
65	thermal oxidizer	14-74	thermal oxidizer 1	0.01	0.02			0.01	0.07			
65	thermal oxidizer	70-74	thermal oxidizer 2	0.01	0.02			0.01	0.07			
65	thermal oxidizer	?-74	thermal oxidizer 3	0.01	0.02			0.01	0.07			
65	FCCU	86-74	vent-FCCU regenerator	0.08	0.22	0.27		0.22				
67	coker	2-84	flare-coker	0.06				0.44				
67	utilities	3-84	flare-east	0.81				2.50				
67	GO	1-90	flare-GO-1	0.10				0.05				
67	west OPS	9-84	flare-ground					0.58				
67	HCU	4-84	flare-HCU	0.16				20.10				
67	marine vessel loading	5-89	flare-marine vapor recovery	1.17	0.36	0.06		0.29			0.01	
67	west OPS	5-84	flare-west	0.10				0.20				
67	distribution	3003-95	fugitives-distribution	9.48	17.25	15.70		8.78		4.26	4.54	
67	marine vessel loading	3012-95	fugitives-marine vapor recove	0.13	0.01			0.04				
67	tank	1006-95	tank	0.02								
67	tank	1007-95	tank	0.02								
67	tank	1071-95	tank							0.05	0.13	
67	tank	1072-95	tank							0.05	0.15	
67	tank	1207-95	tank-external float	0.03	0.01	0.01						
67	tank	1248-95	tank-external float	0.06	0.04	0.01		0.02				
67	tank	1232-95	tank-external float	0.02	0.07	0.01		0.12				
67	tank	1231-95	tank-external float	0.02	0.08	0.02		0.14				
67	tank	1246-95	tank-external float	0.08	0.08	0.04		0.03			0.03	
67	tank	1265-95	tank-external float	0.31	0.05	0.04		0.02				
67	tank	1204-95	tank-external float	0.34	0.05	0.01		0.02				
67	tank	1225-95	tank-external float	0.04	0.12	0.03		0.22			0.01	
67	tank	1226-95	tank-external float	0.04	0.12	0.03		0.22			0.01	
67	tank	1247-95	tank-external float	0.02	0.04	0.02		0.37			0.01	
67	tank	1242-95	tank-external float	0.04	0.12	0.03		0.28			0.01	
67	crude tank group	5002-97	tank-external float	0.09	0.11	0.01		0.27				
67	tank	1228-95	tank-external float	0.15	0.50	0.11		0.88			0.03	

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
67	tank	1229-95	tank-external float	0.16	0.53	0.12		0.95			0.04	
67	tank	1227-95	tank-external float	0.16	0.54	0.12		0.95			0.04	
67	tank	1253-95	tank-external float	0.20	0.67	0.15		1.20			0.04	
67	tank	1254-95	tank-external float	0.20	0.67	0.15		1.20			0.04	
67	tank	1255-95	tank-external float	0.20	0.67	0.15		1.20			0.04	
67	tank	1241-95	tank-external float	0.15	0.50	0.11		2.93			0.03	
67	tank	1233-95	tank-external float	2.45	1.51	0.12		1.22			0.04	
67	tank	1023-95	tank-fixed roof	0.08						0.04	0.06	
67	tank	1022-95	tank-fixed roof	0.09						0.05	0.07	
67	tank	1044-95	tank-fixed roof	0.11	0.19	0.03				0.01		
67	tank	1045-95	tank-fixed roof	0.11	0.19	0.03				0.01		
67	tank	1073-95	tank-fixed roof	1.64	5.92	2.08				0.09	2.60	
67	tank	1074-95	tank-fixed roof	3.71	13.42	4.72				0.16	5.88	
67	tank	1075-95	tank-fixed roof	3.71	13.42	4.72				0.16	5.88	
67	tank	1028-95	tank-gas oil-fixed roof	0.02								
67	tank	1029-95	tank-gas oil-fixed roof	0.02								
67	tank	1030-95	tank-gas oil-fixed roof	0.10						0.06		
67	tank	1026-95	tank-gas oil-fixed roof	0.08						0.04	0.06	
67	tank	1024-95	tank-gas oil-fixed roof	0.09						0.05	0.07	
67	tank	1025-95	tank-gas oil-fixed roof	0.09						0.05	0.07	
67	tank	1027-95	tank-gas oil-fixed roof	0.09						0.05	0.07	
67	tank	1036-95	tank-gas oil-fixed roof	0.12						0.06	0.10	
67	tank	1263-95	tank-internal float	0.05	0.03	0.01		0.02				
67	tank	1224-95	tank-internal float	0.20	0.10			0.10				
67	tank	1230-95	tank-internal float	0.09	0.29	0.06		0.51			0.02	
67	tank	1048-95	tank-kerosene-fixed roof	0.10								
67	tank	1041-95	tank-kerosene-fixed roof	0.09	0.19	0.03				0.01		
67	tank	1042-95	tank-kerosene-fixed roof	0.09	0.19	0.03				0.01		
67	tank	1043-95	tank-kerosene-fixed roof	0.09	0.19	0.03				0.01		
67	tank	1047-95	tank-kerosene-fixed roof	0.09	0.19	0.03				0.01		
67	wharf loading - uncontrolle	3307-95	wharf loading - uncontrolled	0.22	0.36	0.05				0.12	0.07	0.06
68	marine vessel loading	1-92	flare-marine loading	0.18	1.28	0.57	2.57	0.18			0.01	
68	flare	20-72	flare-North	0.04	0.02				0.07			
68	flare	3-77	flare-South	0.04	0.02				0.07			
68	fugitives	fugitives	fugitives -leaks	8.99	4.79	2.89	7.10	17.30		0.01	0.55	

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
68	loading	5-88	loading-river dock	0.05	0.10	0.14		0.11		0.01	0.02	
68	tank	80-16	tank-MTBE				0.57					
68	tanks	cap-crude	tanks-crude oil (7)	0.03	0.02	0.01		0.14			0.00	
68	tanks	cap-gasolin	tanks-gasoline (7)	0.24	0.23	0.10	3.50	0.24			0.02	
68	tanks	cap-mid	tanks-middle distillate (6)	0.20	0.35	0.49		0.41		0.00	0.08	
68	tanks	cap-naphtha	tanks-naphtha (2)	0.03	0.02	0.01		0.26			0.00	
68	tanks	25-2	tank-sourwater	0.01	0.00			0.05				
68	tanks	cap-slop oil	tanks-slop oil (2)	0.06	0.17	0.25		0.49			0.03	
68	wastewater treatment	80-14	tank-wwt	0.01	0.02	0.02		0.02			0.00	
68	wastewater treatment	80-17	tank-wwt	0.01	0.01	0.01		0.12			0.00	
68	wastewater treatment	150-2	tank-wwt	0.39	0.23	0.14		3.26			0.03	
70	tank	t-504	cone roof tank-MEK/toluene		0.06							
70	tank	t-147	cone roof tank-MEK/toluene		0.07							
70	tank	t-149	cone roof tank-MEK/toluene		0.14							
70	tank	t-503	cone roof tank-MEK/toluene		0.22							
70	tank	t-402	cone roof tank-MEK/toluene		0.23							
70	tank	t-301	cone roof tank-MEK/toluene		0.40							
70	tank	t-145	cone roof tank-toluene		0.06							
70	Udex	ctudx	cooling tower	0.25	0.29	0.05		0.12			0.01	
70	Lubes	ctlub	cooling tower	0.40	0.45	0.08		0.19			0.02	
70	Marley	ctmar	cooling tower	0.52	0.59	0.11		0.25			0.02	
70	gasoline bulk terminal	vi-ia	flare	0.69	3.51	1.98		0.74		0.03	0.51	0.61
70	truck loading	futl	fugitives	0.02	0.59	0.11		0.23			0.02	0.00
70	wastewater treatment-drains	vi-a	fugitives	1.94	5.37	2.63		1.24		0.07	0.20	0.93
70	West process area	fuwp	fugitives	0.60	18.60	3.37		7.20		0.01	0.67	0.07
70	East process area	fuep	fugitives	1.17	36.10	6.52		13.96			1.30	0.14
70	tank farm/CCU area	futfccu	fugitives	1.20	37.80	6.80		14.60			1.36	0.14
70	residual	t-174	tank cone roof	0.05	0.05	0.03						
70	distillate tanks	t-72	tank cone roof distillate			0.02					0.00	0.00
70	distillate tanks	t-73	tank cone roof distillate			0.02					0.00	0.00
70	distillate tanks	t-47	tank cone roof distillate	0.01	0.01	0.01						
70	distillate tanks	t-48	tank cone roof distillate	0.02	0.02	0.01						
70	distillate tanks	t-52	tank cone roof distillate			0.07					0.01	0.00
70	tank-gasoline	t-29	tank cone roof gasoline	0.47	0.02			2.09				
70	lube oil	t-64	tank cone roof lube oil	0.01		0.00						0.00

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
70	tank slop oil	t-59	tank cone roof slop oil	0.07	0.04	0.01		2.20			0.00	0.00
70	crude	t-60	tank floating roof crude	0.00	0.00	0.00		0.01			0.00	0.00
70	crude	t-49	tank floating roof crude	0.01	0.01	0.00					0.00	
70	crude	t-77	tank floating roof crude	0.03	0.01	0.00		0.01			0.00	0.00
70	crude	t-43	tank floating roof crude	0.06	0.06	0.02		0.04			0.00	0.00
70	crude	t-61	tank floating roof crude	0.02	0.07	0.03		0.05			0.01	0.01
70	crude	t-44	tank floating roof crude	0.10	0.07	0.01		0.07			0.00	0.00
70	crude	t-175	tank floating roof crude	0.12	0.24	0.04		0.06			0.01	
70	distillate tanks	t-50	tank floating roof distillate			0.01					0.00	0.00
70	tank	t-55	tank floating roof distillate	0.07	0.11	0.02		0.01				0.00
70	tank-gasoline	t-26	tank floating roof gasoline	0.03	0.00	0.00						
70	tank-gasoline	t-27	tank floating roof gasoline	0.01				0.04				
70	tank-gasoline	t-32	tank floating roof gasoline	0.01	0.00			0.05				
70	tank-gasoline	t-30	tank floating roof gasoline	0.01	0.00			0.05				
70	tank-gasoline	t-53	tank floating roof gasoline	0.02	0.06	0.02		0.04				0.01
70	tank-gasoline	t-56	tank floating roof gasoline	0.06	0.09	0.02		0.00			0.01	0.00
70	tank-gasoline	t-58	tank floating roof gasoline	0.03	0.08	0.02		0.06			0.01	0.01
70	tank-gasoline	t-67	tank floating roof gasoline	0.05	0.12	0.03		0.12			0.01	0.01
70	tank-gasoline	t-68	tank floating roof gasoline	0.05	0.12	0.03		0.12			0.01	0.01
70	tank-gasoline	t-76	tank floating roof gasoline	0.06	0.15	0.04		0.14			0.01	0.01
70	tank-gasoline	t-57	tank floating roof gasoline	0.06				0.53				
70	tank	t-54	tank floating roof lube oil	0.06	0.01	0.03		0.02			0.01	0.01
70	tank slop oil	t-69	tank floating roof slop oil	0.00	0.00	0.00		0.02			0.00	0.00
70	tank	t-199	tank-cone roof distillate			0.09						
70	wastewater treatment	t-188	tank-open top wastewater stor	0.07	0.08	0.17		0.20			0.10	
73	wastewater treatment	308-T-16/17	bio treatment	0.09	0.03	0.14					0.07	
73	cooling tower	303-R-1	cooling tower	0.28	0.06	0.06		0.02		0.00	0.02	0.01
73	wastewater treatment	308-R-1	cooling tower	0.54	0.15	0.12		0.03		0.00	0.04	0.02
73	marine vessel loading	406-D-15	flare	1.80	0.12	0.07	2.80	0.69			0.01	0.01
73	marine vessel loading	406-D-16	flare	1.80	0.12	0.07	2.80	0.69			0.01	0.01
73	hydrotreater (diesel)	292-FF	Fugitives		0.02	0.03		0.01		0.01		
73	merox unit	7591-FF	fugitives	0.01	0.05	0.01		0.01				0.01
73	naphfining	291-FF	Fugitives	0.00	0.12	0.14		0.13		0.00	0.03	0.02
73	light ends recovery	6191-FF	fugitives	0.14	0.09	0.01		0.12			0.09	
73	saturate gas unit	7991-FF	Fugitives	0.20	0.14	0.14		0.30		0.00	0.48	0.06

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzen	Trimethyl benzene
73	crude unit	191-FF	Fugitives	0.25	0.46	0.58		1.50		0.06	0.16	0.12
73	marine vessel loading	406N-FF	Fugitives	0.30	0.11	0.09		3.00		0.01	0.06	0.01
73	marine vessel loading	406E-FF	Fugitives	0.30	0.11	0.09		3.00		0.01	0.06	0.01
73	catalytic reforming	1391-FF	Fugitives	0.67	1.50	1.20		0.39		0.09	0.29	0.48
73	benzene-hydrodealkylation	1792-FF	Fugitives	2.70	3.20	2.50		0.32		0.00	0.77	0.11
73	aromatic extraction from re	1791-FF	Fugitives	3.40	4.70	3.90		0.52		0.01	1.10	0.17
73	tank farm	412-A-FF	fugitives-nonSOCMI tank far	0.38	2.07	1.62		0.58		0.14	0.37	0.58
73	tank farm	412-FF	fugitives-SOCMI tank farm	1.53	2.12	1.73		0.23			0.49	0.08
73	wastewater treatment	308-FF	fugitives-WW collection and	6.30	7.00	10.00					2.10	
73	landfarm	308-landfar	landfarm	0.02	0.00	0.00						
73	marine vessel loading	406-N	Product dock loading	0.07	0.16	14.60					2.30	
73	marine vessel loading	406-X	Product dock loading	0.07	0.16	14.60					2.30	
73	wastewater treatment	308-T-11	skimmed oil tank	0.02	0.01	0.00						
73	THD charge tank	100-T-103	Tank	0.77	0.27						0.02	0.01
73	tank farm	100-T-204	tank-alkylate	0.12	0.16	0.05		0.03			0.01	0.03
73	tank farm	100-T-400	tank-benzene	0.57								
73	benzene prod	100-T-107	tank-benzene	0.57								
73	benzene prod	100-T-108	tank-benzene	0.57								
73	tank farm	100-T-310	tank-diesel	0.13	0.13	0.11	0.02	0.05			0.03	0.49
73	tank farm	100-T-311	tank-diesel	0.13	0.13	0.11	0.02	0.05			0.03	0.49
73	tank farm	100-T-312	tank-diesel	0.13	0.13	0.11	0.02	0.05			0.03	0.49
73	tank farm	100-T-313	tank-diesel	0.13	0.13	0.11	0.02	0.05			0.03	0.49
73	tank farm	100-T-350	tank-diesel	0.13	0.13	0.11	0.02	0.05			0.03	0.49
73	wastewater treatment	308-T-14	tank-equalization	0.88	1.10	0.00						
73	crude storage	100-T-001	Tank-FR-crude	0.01	0.00	0.00		0.00				0.00
73	crude storage	100-T-002	Tank-FR-crude	0.007	0.003	0.001		0.004				0.001
73	crude storage	100-T-003	Tank-FR-crude	0.007	0.003	0.001		0.004				0.001
73	crude storage	100-T-004	Tank-FR-crude	0.007	0.003	0.001		0.004				0.001
73	crude storage	100-T-005	Tank-FR-crude	0.007	0.003	0.001		0.004				0.001
73	crude storage	100-T-006	Tank-FR-crude	0.007	0.003	0.001		0.004				0.001
73	crude storage	100-T-007	Tank-FR-crude	0.007	0.003	0.001		0.004				0.001
73	Naphtha	100-T-104	Tank-FR-naphtha	0.01	0.00	0.00		0.00			0.00	0.00
73	Naphtha	100-T-105	Tank-FR-naphtha	0.01	0.00	0.00		0.00			0.00	0.00
73	tank farm	100-T-302	tank-gasoline	0.03	0.04	0.01	0.00	0.01			0.00	0.01
73	tank farm	100-T-303	tank-gasoline	0.03	0.04	0.01	0.00	0.01			0.00	0.01

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Benzene	Toluene	Xylene	Methyl t-butyl	Hexane	Formaldehyd	Naphthalene	Ethyl benzene	Trimethyl benzene
73	tank farm	100-T-351	tank-gasoline	0.03	0.04	0.01	0.00	0.01			0.00	0.01
73	tank farm	100-T-200	tank-gasoline	0.12	0.16	0.05		0.03			0.01	0.03
73	tank farm	100-T-202	tank-gasoline	0.12	0.16	0.05		0.03			0.01	0.03
73	tank farm	100-T-211	tank-heavy FCC gasoline	0.03	0.05	0.01		0.01			0.00	0.01
73	tank farm	100-T-325	tank-heavy raffinate	0.03	0.05	0.01		0.01			0.00	0.01
73	tank farm	100-T-213	tank-heavy reformate	0.03	0.05	0.01		0.01			0.00	0.01
73	tank farm	100-T0212	tank-light FCC gasoline	0.12	0.16	0.05		0.03			0.01	0.03
73	tank farm	100-T-251	tank-light raffinate	0.03	0.04	0.01	0.00	0.01			0.00	0.01
73	Reformer	100-T-106	tank-light reformate	0.77	0.27						0.02	0.01
73	wastewater treatment	308-T-73	tank-neutralized caustic	0.01	0.03	0.03					0.01	0.00
73	wastewater treatment	308-T-76	tank-neutralized caustic	0.01	0.03	0.03					0.01	0.00
73	wastewater treatment	308-T-15A	tank-storm water	0.02	0.01	1.30						
73	wastewater treatment	308-T-15B	tank-storm water	0.02	0.01	1.30						
73	tank farm	100-T-113	tank-swing	1.16	0.56	0.21	3.20	0.05			0.02	0.07
73	tank farm	100-T-250	tank-swing	1.16	0.56	0.21	3.20	0.05			0.02	0.07
73	tank farm	100-T-326	tank-swing	1.16	0.56	0.21	3.20	0.05			0.02	0.07
73	tank farm	100-T-201	tank-xylene			0.13						
73	tank farm	100-T-203	tank-xylene			0.13						
73	wastewater treatment	308-W-43	thermal oxidizer-wwt	1.34	0.17	0.26					0.06	
74	cooling tower	7-96	cooling tower	0.18	0.18	0.18	0.18	0.18	5.26		0.18	
74	flare	6-96	flares					1.56				
74	fugitives	9-96	fugitives	5.10	12.20	15.70	23.60	46.40		0.63	2.93	4.05
74	loading	3-96	loading	0.51	1.91	4.56	0.59	0.56		0.17	0.78	1.75
74	tank farm	2-96	tanks-fixed roof	0.07	0.18	0.23		0.15				
74	tank farm	1-96	tanks-floating roof	0.76	0.87	1.10	1.24	0.95			0.08	
74	wastewater treatment	8-96	wastewater treatment	9.79	4.23	3.94	0.95	0.80	1.54	0.01	1.41	

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Biphenyl	Cumene	1,3 Butadiene	MEK	MIBK	Phenol	Methanol	2,2,4-Trimethylpentane
61	fugitives	3misc6	fugitives-miscellaneous		0.03	0.11				3.29	
61	alcohol tanks	3ix29	tank-alcohol FR 3 tanks							1.24	
61	wastewater treatment	3ix37	wastewater treatment		0.07	0.09				1.19	
63	tank farm	tanks-cb	catch basin								0.18
63	lube, dewax, hydrofining	96	condensate blowdown drum				10.10	0.50			
63	alkylation - light ends	vle-ct	cooling tower								0.28
63	wastewater treatment	wcla-off	figitives-offsite		0.12		1.96	0.18	1.56	3.00	
63	hydroprocessing	hydro-fug	fugitives	0.10							
63	Reformer	reform-fug	fugitives		0.16						
63	light oil finishing	lofu-fug	fugitives	0.16	0.13						
63	light hydrocarbon recovery	c3st-fug	fugitives							0.58	
63	distillation-"pipestill"	psla-fug	fugitives	0.56	0.30						
63	alkylation - light ends	vle-fug	fugitives							2.21	
63	docks complex	docks-fug	fugitives							1.03	2.90
63	wastewater treatment	wcla-fug	fugitives		0.52		1.65	0.92		2.76	
63	tank farm	tanks-fug	fugitives	0.43	0.22					5.01	9.47
63	lube, dewax, hydrofining	spec-fug	fugitives				30.10				
63	lube, dewax, hydrofining	spec-solv	solvent emissions				335.00	165.00		7.00	
63	docks complex	m-tanks	tanks								2.30
63	tank farm	ref-tanks	tanks		0.49	0.31				1.50	49.10
64	coker -API	1C	coker #1	0.01							
64	coker -API	2C	coker #2	0.01							
64	fugitives	FE	fugitives -leaks	0.12	0.11	0.07					6.00
64	loading-truck rack	1-96	loading - truck		0.01						0.11
64	loading-product	LD	loading product		0.02						
64	tanks	2-96	tanks-diesel/gasoline	0.01	0.01						0.67
64	tanks	GO-TK	tanks-FCC feed (gas oil)	0.01	0.02						
64	tanks	FG-TK	tanks-gasoline		0.03						2.01
64	tanks	UG-TK	tanks-gasoline(unfinished)		0.02	0.01					1.20
64	wastewater treatment	WW-TK	tanks-wastewater	0.01							
65	marine vessel loading	107-90	flare								1.15
65	pipeline	unit 63	fugitives								0.02
65	marine vessel loading	134-96	loading-uncontrolled		0.01						
65	tanks	AL-TK	tank-alkylate (2)								2.30
65	tanks	GO_TK	tank-gas oil (1)	0.04	0.03						

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Biphenyl	Cumene	1,3 Butadiene	MEK	MIBK	Phenol	Methanol	2,2,4-Trimethylpentane
65	tanks	SHVO-TK	tank-HVGO feed (1)	0.00	0.00						
65	tanks	FO-TK	tanks-fuel oil (11)		0.05						
65	tanks	SG-Tk	tank-sour gas oil (2)	0.00	0.00						
67	fractionation plant	3-93	flare-fractionation			0.30					
67	GO	1-90	flare-GO-1			0.20					
67	west OPS	9-84	flare-ground			3.41					
67	west OPS	5-84	flare-west			5.40					
68	fugitives	fugitives	fugitives -leaks		0.02	0.18					
70	tank	t-146	cone roof tank-MEK				0.13				
70	tank	t-504	cone roof tank-MEK/toluene				0.42				
70	tank	t-149	cone roof tank-MEK/toluene				0.75				
70	tank	t-147	cone roof tank-MEK/toluene				0.92				
70	tank	t-503	cone roof tank-MEK/toluene				2.89				
70	tank	t-402	cone roof tank-MEK/toluene				3.09				
70	tank	t-301	cone roof tank-MEK/toluene				5.10				
70	Udex	ctudx	cooling tower				0.42				
70	Lubes	ctlub	cooling tower				0.66				
70	Marley	ctmar	cooling tower				0.87				
70	gasoline bulk terminal	vi-ia	flare		0.03						
70	West process area	fuwp	fugitives		0.07						
70	tank farm/CCU area	futfccu	fugitives		0.14		7.29				
70	wastewater treatment-drains&sepa	vi-a	fugitives		0.03		13.23				
70	East process area	fuep	fugitives		0.13		138.50				
70	wastewater treatment	t-188	nk-open top wastewater storage				0.01				
73	cooling tower	303-R-1	cooling tower		0.01	0.00					
73	wastewater treatment	308-R-1	cooling tower		0.02	0.01					
73	marine vessel loading	406N-FF	Fugitives		0.01						
73	marine vessel loading	406E-FF	Fugitives		0.01						
73	saturate gas unit	7991-FF	Fugitives		0.01						
73	merox unit	7591-FF	fugitives		0.01						
73	crude unit	191-FF	Fugitives		0.03	0.01					
73	light ends recovery	6191-FF	fugitives			0.18					
73	catalytic reforming	1391-FF	Fugitives		0.03	0.19					
73	benzene-hydrodealkylation	1792-FF	Fugitives		0.49						
73	aromatic extraction from reformate	1791-FF	Fugitives		0.80						

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	Biphenyl	Cumene	1,3 Butadiene	MEK	MIBK	Phenol	Methanol	2,2,4-Trimethylpentane
73	tank farm	412-A-FF	ugitives-nonSOCMI tank farm		0.05						
73	tank farm	412-FF	fugitives-SOCMI tank farm		0.36						
73	THD charge tank	100-T-103	Tank		0.01						
73	tank farm	100-T-204	tank-alkylate		0.03	0.01					
73	tank farm	100-T-310	tank-diesel		0.02						
73	tank farm	100-T-311	tank-diesel		0.02						
73	tank farm	100-T-312	tank-diesel		0.02						
73	tank farm	100-T-313	tank-diesel		0.02						
73	tank farm	100-T-350	tank-diesel		0.02						
73	tank farm	100-T-200	tank-gasoline		0.03	0.01					
73	tank farm	100-T-202	tank-gasoline		0.03	0.01					
73	tank farm	100-T-211	tank-heavy FCC gasoline		0.01	0.00					
73	tank farm	100-T-325	tank-heavy raffinate		0.01	0.00					
73	tank farm	100-T-213	tank-heavy reformate		0.01	0.00					
73	tank farm	100-T0212	tank-light FCC gasoline		0.03	0.01					
73	Reformer	100-T-106	tank-light reformate		0.01						
73	tank farm	100-T-113	tank-swing		0.04	0.01					
73	tank farm	100-T-250	tank-swing		0.04	0.01					
73	tank farm	100-T-326	tank-swing		0.04	0.01					
74	cooling tower	7-96	cooling tower							0.18	
74	flare	6-96	flares			0.09					
74	fugitives	9-96	fugitives		0.35	0.22				27.40	0.74
74	loading	3-96	loading		0.16						0.03
74	wastewater treatment	8-96	wastewater treatment			0.02			0.21	0.12	0.34

TABLE A-8. HAP EMISSION ESTIMATES FROM PERMIT APPLICATIONS (tpy)

ID	Process	Source	Description	2-Methyl naphthalene	PNA/ PAH	Anthracene	Chrysene	Fluorene	Phenanthren	Pyrene	Cresol
61	fugitives	3misc6	fugitives-miscellaneous	0.52				0.01	0.03		
61	distillate tanks	3ix22	tank-distillate fixed-12 tanks	0.94		0.08	0.07	0.12	0.49	0.13	
61	kerosene tanks	3ix21	tank-kerosene FR 11 tanks	0.20							
63	light hydrocarbon recovery	c3st-fug	fugitives						0.11		
63	Reformer	reform-fug	fugitives						0.12		
63	alkylation - light ends	vle-fug	fugitives						0.16		
63	docks complex	m-fug	fugitives						0.30		
63	docks complex	docks-fug	fugitives						0.47		
63	hydroprocessing	hydro-fug	fugitives						0.67		
63	light oil finishing	lofu-fug	fugitives						0.69		
63	tank farm	tanks-fug	fugitives			0.35			2.80		
63	distillation-"pipestill"	psla-fug	fugitives			0.44			3.63		
63	tank farm	ref-tanks	tanks		20.60						
64	coker -API	1C	coker #1								0.04
64	coker -API	2C	coker #2								0.04
64	fugitives	FE	fugitives -leaks			0.08					0.29
64	loading-truck rack	1-96	loading - truck								0.01
64	wastewater treatment	AS	sump-alky								0.01
64	tanks	2-96	tanks-diesel/gasoline								0.05
64	tanks	GO-TK	tanks-FCC feed (gas oil)								0.01
64	tanks	UD-TK	tanks-unfinished distillate								0.01
64	wastewater treatment	WW-TK	tanks-wastewater								0.05
68	loading	5-88	loading-river dock		0.02						
74	fugitives	9-96	fugitives		20.70						