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VOC/HAP Emissions from Marine Vessel Loading Operations

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Technical Support Document for Proposed Standards

EPA-450/3-92-001a

TECHNICAL SUPPORT DOCUMENT FOR THE DEVELOPMENT OF A VOC RULE FOR MARINE VESSEL LOADING OPERATIONS

EMISSION STANDARDS DIVISION

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

May 1992

ENVIRONMENTAL PROTECTION AGENCY

Background Information
and Draft
Environmental Impact Statement
for Tank Vessel Loading Operations

Prepared by:

1/10/93
(Date)

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1. The proposed standards would significantly reduce emissions from marine tank vessel loading operations. Under Section 183(f) of the Clean Air Act Amendments, EPA is obligated to promulgate standards applicable to VOC's and any other air pollutant which causes, or contributes to, or may be reasonably anticipated to endanger public health or welfare.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.

3. The comment period for review of this document is 60 days from the date of publication of the proposed standard in the Federal Register. Mr. David Markwordt may be contacted at (919) 541-0837 regarding the date of the comment period.

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1.0 INDUSTRY DESCRIPTION

1.1 BACKGROUND

When tankships and barges are loaded with volatile liquids, volatile organic compound (VOC) vapors are expelled from the cargo tanks and, if uncontrolled, emitted to the atmosphere. These vapors, primarily hydrocarbons, form ozone in the presence of sunlight; ozone contributes to smog, which exacerbates respiratory problems in the general populace. In addition, hazardous air pollutants (HAP's) may comprise some or all of the VOC's emitted during marine vessel loading operations. Several State and local governments have enacted regulations to control VOC emissions from the loading of tankships and barges. The earliest compliance date associated with these regulations is in 1991. The primary purpose of these State and local regulations is to help these areas reduce ambient air concentrations of ozone under the National Ambient Air Quality Standards administered by the Environmental Protection Agency (EPA) and limit human exposure to HAP's.

Benzene emissions from marine vessel loading are also controlled, primarily to reduce occupational exposure to benzene vapors. A national emission standard for benzene emissions promulgated in 1990 (the benzene NESHAP) requires facilities loading more than 1.3 million liters per year (l/yr) (8,200 barrels per year [bbl/yr]) of at least 70 percent by weight benzene to control emissions.[1] Terminals subject to this regulation are required to reduce benzene emissions by 98 percent.

The addition of improperly designed vapor-handling systems could present a safety hazard to marine vessel loading operations

by increasing the operational complexity of loading operations and in particular by requiring additional handling of potentially explosive vapors. Unsafe design or operation of vapor control systems could result in fires and explosions, tank ruptures, and spills.[2] However, a well-designed control system can advance safety by properly handling vapors throughout the loading process. Therefore, the Coast Guard, which is responsible for the safety of waterborne commerce, requested in 1986 that the National Research Council (NRC) conduct a study to assess the technical, safety, and economic aspects of controlling hydrocarbon emissions from marine vessel loading operations. Participants in the NRC study included the Coast Guard, EPA, the Maritime Administration, the States of Texas, Louisiana, and New Jersey, the Bay Area Air Quality Management District (BAAQMD), and industry representatives. The result of this study is the document Controlling Hydrocarbon Emissions From Tank Vessel Loading (referred to elsewhere in this report as "the Marine Board document"). Much of the information contained in this report was taken from the Marine Board document.[3]

The committee concluded in January 1987 that controls were technically feasible but that there was a need for the Coast Guard to promulgate safety requirements and a need for EPA to set uniform emission standards to mitigate some of the safety issues that could arise from varied State regulations and eliminate the possibility of State regulations disrupting interstate commerce.[3] The Coast Guard has subsequently adopted new regulations for the safe design, installation, and operation of marine vapor control systems.[2] These regulations became effective on July 23, 1990. The Clean Air Act Amendments (CAAA) of 1990 require EPA to promulgate a national tank vessel loading rule by the fall of 1992.

1.2 STATE REGULATIONS

The States of Louisiana, Pennsylvania, and New Jersey and authorities in the San Francisco Bay Area and South Coast Air Basin have enacted regulations to control VOC emissions from

marine vessel loading operations. The State of Alaska has proposed a similar regulation.[4,5] Table 1-1 provides a comparison of the State and local regulations governing marine vessel loading.[4] The regulations presented in Table 1-1 have different requirements with respect to the types of terminals affected, the required emission reductions, the affected hydrocarbons (VOC's), and compliance dates. The most stringent regulation is the BAAQMD's Rule 44, which affects all terminals regardless of throughput or types of commodities loaded. Because of the differing requirements, tank vessels compatible with an emission control system accepted in one area might not be compatible with the regulations or equipment in another.[4] Therefore, EPA is developing a rule for marine vessel loading operations to promote nationwide installation of comparable emission control systems on vessels and at marine terminals.

1.3 WCUS DATA BASE

A primary source of information for developing VOC emissions estimates for marine vessel loading operations is the Army Corps of Engineers' Waterborne Commerce of the United States (WCUS) data base. The WCUS data base contains detailed information on the types and quantities of commodities loaded and unloaded at U.S. ports, harbors, waterways, and canals. The portion of the 1988 WCUS data base containing information about commodities loaded in bulk that emit VOC's and/or HAP's was extracted and is referred to elsewhere in this report as "the data base."

In its original form, the data base contained information about 1,800 terminals loading commodities in 13 different categories. Of the 1,800, 133 terminals had throughputs of 1,000 bbl/yr or less. These 133 terminals were removed from the data base because loadings at a terminal that constitute the 1,000 bbl/yr or less do not represent bulk loadings (i.e., the liquids are likely carried in containers). Of the remaining 1,667 terminals, 119 are affected by promulgated State regulations (CA, NJ, LA, PA). There are two locally regulated areas in California, the San Francisco Bay area, and the South Coast Air Basin; both have promulgated regulations.

TABLE 1-1. COMPARISON OF STATE AND LOCAL REGULATIONS GOVERNING MARINE LOADING[a]

	San Francisco Bay Area	South Coast Air Basin (California)	Louisiana
Regulation name	Rule 44	Rule 1142	Rule 2108
Governing body	Bay Area Air Quality Management District (BAAQMD)	South Coast Air Basi	Louisiana Department of Environmental Quality (LA DEQ)
Gasoline emissions	5.7 mg/L or 95% reduction	95% reduction	70 mg/L for barges 30 mg/L for ships
Crude oil emissions	5.7 mg/L or 95% reduction	95% reduction	30 mg/L for barges 12 mg/L for ships
Other VOC emissions[b]	5.7 mg/L or 95% reduction	95% reduction	30 mg/L for barges 12 mg/L for ships
Affected facilities	All terminals	All terminals that have a loding event greater than 1,000 bbl	All with uncontrolled emissions > 100 tons/yr
Compliance dates	July 1, 1991, for all facilities that loaded more than 1 million bbl/yr in any calendar year after 1985		December 31, 1991, for gasoline and other VOC May 1, 1992, for crude oil
Special notes	Small terminal is one loading less than 1 million bbl/yr	Loading events include loading and unloading, ballasting ito nonsegregated ballast tanks, and housekeeping operations	90% reduction in emissions is allowable instead of mg/L limits Allows the use of open flares if they are designed and operated per EPA guidelines
Regulation name	NJAC-7-27-16.3	18 AAC 50, 105, 500, and 900 (proposed regulation)	29 PA, CODE CHS, 121, 129 and 139
Governing body	New Jersey Department of Environmental Protection (NJ DEP)	Alaska Department of Environmental Conservation (AK DEC)	Environmental Quality Board (EQB)
Gasoline emissions	95% reduction	95% reduction or 2 lb/1,000 bbl	90% reduction
Crude oil emissions	Exempt	95% reduction or 2 lb/1,000 bbl	Exempt
Other VOC emissions[b]	Exempt	95% reduction or 2 lb/1,000 bbl	Exempt
Affected facilities	All loading more than 6 million gal/yr of gasoline	All terminals with throughputs greater than 5 million bbl/yr or with uncontrolled VOC emissions greater than or equal to 250 tons	All terminals
Compliance dates	June 21, 1991	June 1992	September, 1996
Special notes	Any facility that loads 60,000 gal/d between May 1 and September 15 is affected	Facilities emitting 250 tons (or greater) of VOC's per year are considered "major" facilities Alaska's proposed regulation was patterned after the rules developed by the BAAQMD	The proposed amendments require control of ballasting emissions

[a]SOURCE. Chemical Engineering, May 1990.
[b]In San Francisco, VOC's include gasoline blending stocks and aviation fuel; in Louisiana, they include any VOC that boosts a terminal to 100 tons/yr and has a true vapor pressure greater than 1.5 psia (e.g., JP-4 (jet fuel), aviation gas, gasoline blending stocks), at the loading temperature; in the South Coast Air Basin, an emissions limit of 2.0 lb per 1,000 bbl loaded is in force

Because terminals in the data base are identified only by State, the exact locations of terminals in California are not known. Therefore, terminals in California cannot be separated or further distinguished. Consequently, all terminals in California are assumed to be controlled under promulgated regulations and a composite of the two local regulations was applied.

State regulations tend to target (regulate) the more volatile compounds. Therefore, part of the total throughput at a terminal subject to State regulations may remain uncontrolled. For example, terminals in New Jersey that load both gasoline and jet fuel are only required to control the vapors from gasoline; they are not required to control vapors associated with the loading of jet fuel. In this example, the throughput of jet fuel represents the terminal's "residual" or remaining uncontrolled throughput. Approximately 100 of the 119 terminals affected by State or local regulations have residual throughputs. To determine the true impact of a Federal rule to control VOC and HAP emissions from marine vessel loading operations, the throughputs and emissions already controlled under state regulations were removed from the data base. Uncontrolled or "residual" emissions are considered in the data base. Costs to control these emissions were developed based on the worst-case assumption that the residual emissions constituted a separate facility.

Three terminals in Alaska would be affected by the proposed State regulation. It is possible that a national rule could take effect before this proposed regulation were promulgated. Therefore, the 3 terminals affected by proposed State regulations, the 100 facilities subject to promulgated State regulations with "residual" emissions, and the remaining 1,545 terminals now form the "current" data base. Only those emissions that are already controlled under existing regulations were removed from the data base. Figure 1-1 depicts how the original WCUS data base of 1,800 terminals was pared down to the current data base of 1,648 terminals.

- The current data base includes information on 1,648 U.S. terminals that load liquids in at least one of 13 VOC-emitting commodity categories. The amount of each liquid loaded into tankships and barges is provided for each terminal; the total annual throughput for a terminal is equal to the sum of the tankship and barge loadings of each liquid loaded at that terminal. Table 1-2 presents a summary of the commodity categories, the number of terminals that load liquids in each commodity category, and the national annual throughput of liquids in each commodity category.

1.3.1 Commodity Categories

The following 13 commodity categories were identified that contain liquids that emit VOC's and/or HAP's: gasoline, crude oil, jet fuel, naphtha/solvents, alcohols, toluene, distillate fuel, basic chemicals, miscellaneous chemicals, petroleum and coal products, crude products, gum and wood chemicals, and kerosene. Several of the commodity categories represent a wide range of liquids. For example, the basic chemicals category includes over 303 different liquids. The alcohols category includes 16 different alcohols and alcohol mixtures. The gum and wood category represents 12 chemicals (e.g., gum and wood rosins, tall oil, turpentine, etc.). Because the quantity of the individual liquids loaded within a given commodity category was not known, assumptions were made in order to estimate emissions associated with those categories. Therefore, some uncertainty is associated with the VOC and HAP emissions estimates presented in Chapter 2 for those commodity categories that cover a range of possible compounds.

1.3.2 Terminals

There are 1,648 U.S. terminals where liquids in at least one of the 13 VOC and HAP-emitting commodity categories are loaded. The majority of these commodity categories refer to petroleum products. As shown in Table 1-2, 354 terminals (21 percent) in the data base load crude oil, and 469 terminals (28 percent) load gasoline; 76 terminals load both crude oil and gasoline. The remaining 901 terminals load neither crude oil nor gasoline but

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TABLE 1-2. COMMODITIES BY ANNUAL THROUGHPUT[a]

Commodity	Commodity No.[b]	No. of terminals loading	Throughput, 1,000 bbl/yr			Throughput, 1,000 gal/yr		
			Tankships	Barges	Total national	Tankships	Barges	Total national
Gasoline	2911	493	106,000	281,000	387,000	4,463,000	11,811,000	16,274,000
Crude oil	1311	354	1,138,000	247,000	1,385,000	47,763,000	10,388,000	58,151,000[c]
Jet fuel	2912	186	28,900	62,000	91,000	1,213,000	2,589,000	3,802,000
Naphtha, solvents	2917	203	13,700	59,500	73,200	576,000	2,497,000	3,073,000
Alcohols	2813	212	10,600	36,700	47,300	447,000	1,540,000	1,987,000
Toluene	2817	169	2,760	14,300	17,000	112,000	600,000	712,000
Distillate fuel	2914	694	169,000	346,000	515,000	7,083,000	14,532,000	21,615,000
Chemicals[d]		578	127,000	159,000	287,000	5,353,000	6,686,000	12,309,000
Others[e]		378	10,000	49,800	59,800	419,000	2,092,000	2,511,000
Kerosene	2913	116	3,830	9,710	13,500	161,000	408,000	569,000
TOTAL			1,609,000	1,265,000	2,875,000	67,590,000	53,143,000	120,733,000

[a]Numbers have been rounded.
[b]Commodity number as assigned by the Army Corps of Engineers' Water Resources Support Center.
[c]Approximately 47 percent of the total nationwide throughput of crude oil is attributed to one terminal (Alyeska's Valdez, Alaska, terminal).
[d]Includes basic and miscellaneous chemicals.
[e]Includes petroleum and coal products, crude products, and gum and wood chemicals (commodity numbers 2991, 2811, and 2861, respectively).

do load liquids in at least one of the other 11 categories. Because many terminals load liquids in more than one category, the numbers in the "number of terminals loading" column in Table 1-2 do not total to 1,648.

The annual quantity of VOC-emitting liquids loaded at each of the 1,648 terminals varies widely. Table 1-3 shows the distribution of terminals by throughput. The lowest throughput of any remaining terminal is 1,006 barrels per year (bbl/yr); the highest throughput is at a crude oil terminal that loads over 657 million bbl/yr. The total nationwide quantity of VOC-emitting compounds loaded at U.S. terminals in 1988 was 2.7 billion bbl/yr.

As seen in Table 1-3, the majority of terminals have throughputs less than 1 million bbl/yr; approximately 44 percent of those terminals load gasoline and/or crude oil. Only 300 terminals (18 percent) load more than 1 million bbl/yr, and the majority (83 percent) of these terminals load gasoline and/or crude oil. (The annual throughput associated with each terminal in the data base is provided in Appendix E).

TABLE 1-3. NUMBER OF TERMINALS BY THROUGHPUT

Throughput (TP), bbl/yr[a]	No. of terminals	
	All[b]	Gas and crude[c]
1,000 <TP <10,000	1,652	767
10,000 <TP <50,000	405	134
50,000 <TP <100,000	187	80
100,000 <TP <500,000	385	194
500,000 <TP <1,000,000	130	76
1,000,000 <TP <5,000,000	215	135
5,000,000 <TP <10,000,000	50	38
10,000,000 <TP <50,000,000	29	25
TP >50,000,000	6	6
TOTAL	1,648	747

[a]Barrels per year.
[b]Includes all terminals in the current base.
[c]Includes only those terminals in the data base that load gasoline and/or crude oil.

1.4 REFERENCES FOR CHAPTER 1

1. Environmental Protection Agency. National Emissions Standard for Hazardous Air Pollutants; Benzene Emissions From Chemical Manufacturing Process Vents, Industrial Solvent Use, Benzene Waste Operations, Benzene Transfer Operations, and Gasoline Marketing System; Final Rule. Code of Federal Regulations. 40 CFR Part 61. Washington, D.C. Office of Federal Register. March 7, 1990.

2. Department of Transportation. U.S. Coast Guard. Marine Vapor Control Systems; Final Rule. Title 33. Code of Federal Regulations. Part 154 et al. Washington, DC. Office of Federal Register. June 21, 1990.

3. Controlling Hydrocarbon Emissions From Tank Vessel Loading. Marine Board, National Research Council. pp. 1-22. 1987.

4. Hill, J. Controlling Emissions From Marine Loading Operations. Chemical Engineering. pp. 133-143. May 1990.

5. Proposal to Regulate Emissions of Volatile Organic Compounds From Loading Crude Oil Tankers. Alaska Department of Environmental Conservation. Division of Environmental Quality. Juneau, Alaska. May 30, 1990.

2.0 EMISSIONS AND EMISSION CONTROL

This chapter discusses the estimated volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions associated with marine vessel loading operations and the types of control systems available for reducing these emissions. Section 2.1 describes emission sources associated with marine vessel loading. Section 2.2 shows the emission factors used to estimate cargo loading emissions and describes how nationwide emissions were estimated. Emissions from ballasting are outlined in Section 2.3. The different types of emission control technology available for use during loading at marine terminals are presented in Section 2.4. Current practices at marine terminals and potential safety problems are discussed in Section 2.5.

2.1 EMISSION SOURCES

The following two sources of emissions were considered in estimating nationwide VOC and HAP emissions from marine vessel loading operations: (1) emissions discharged during cargo loading and (2) emissions that occur as a result of tankship ballasting. Emissions from cargo loading represent the majority of emissions from marine vessel tanks; ballasting emissions make up only a small percentage of the total emissions.

Figure 2-1 shows how vapors are emitted during cargo loading. When liquid cargo is loaded into a tank, some of the cargo vaporizes; these vapors are then displaced by the incoming liquid and forced out of the vents as the tank is filled. Cargo loading emissions may be divided into two categories: arrival and generated emissions. Arrival emissions are attributed to any vapors remaining in the otherwise empty cargo tanks prior to

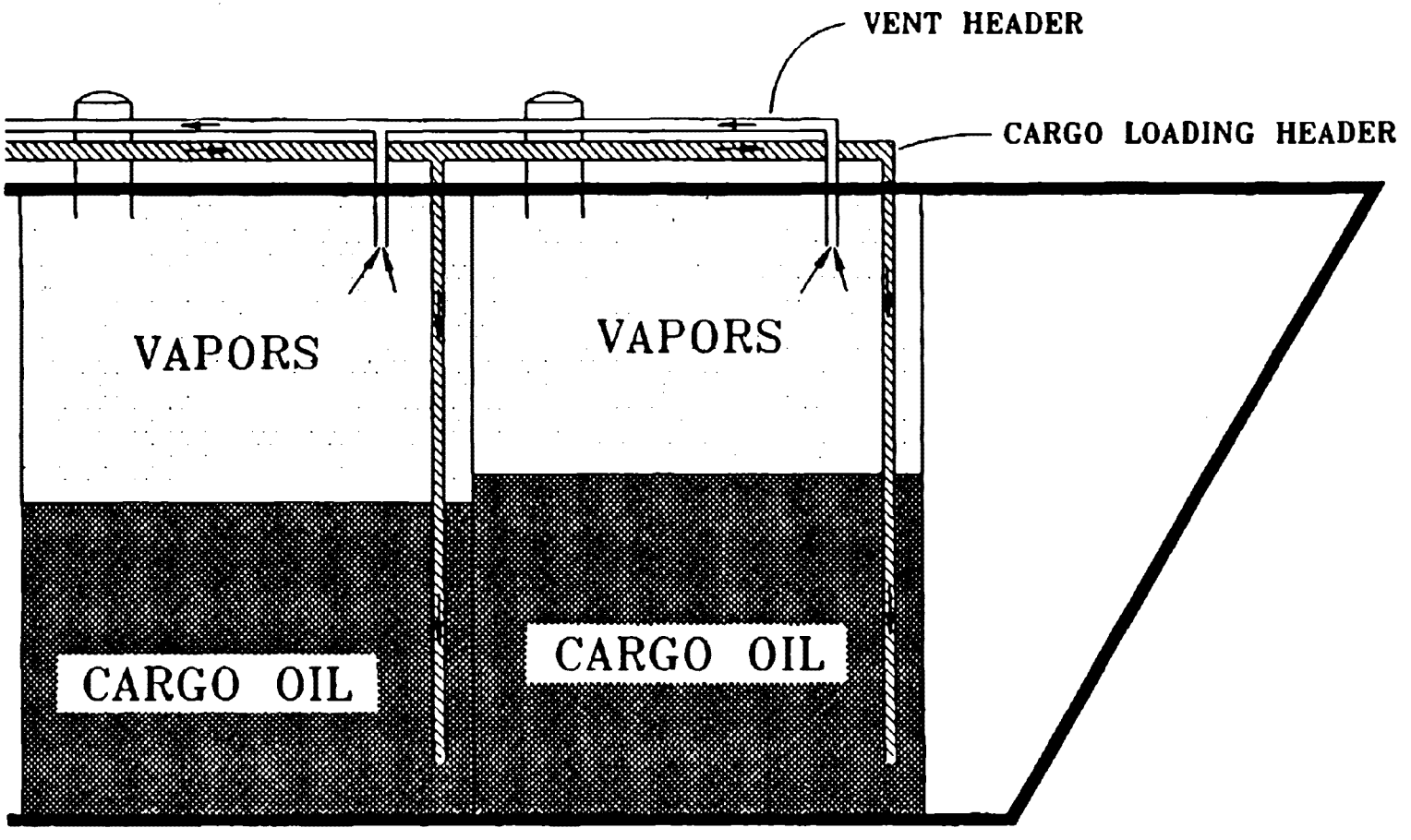

Figure 2-1. Emissions from cargo loading.[1]

loading. Generated emissions refer to the evaporation of cargo as it is loaded.

Emissions from tankship ballasting also occur as a result of vapor displacement. After unloading its cargo, a tankship may travel without cargo; to maintain stability, the tankship pumps water into some of the empty cargo tanks as ballast. Ballasting emissions occur as the ballast water enters the cargo tanks and displaces vapors remaining in the tank from the previous cargo. These vapors are forced through the tank vents and emitted to the atmosphere.

Most tankships have segregated ballast tanks (i.e., separate from the cargo tanks) and, therefore, do not emit vapors during ballasting.[1] New tankships are required to have segregated ballast tanks. Ballasting emissions will further decline as older vessals are retired and replaced with new ones.

2.2 CARGO LOADING: EMISSION FACTORS AND EMISSIONS

The estimated emission factors and emissions associated with cargo loading and tankship ballasting are discussed below.

2.2.1 Cargo Loading Emission Factors

2.2.1.1 VOC Emission Factors. A national estimate of annual VOC emissions from cargo loading was developed using the annual throughputs of each commodity provided in the Waterborne Commerce of the United States (WCUS) data base and both theoretically and empirically derived emission factors. Emission factors from the EPA document "Compilation of Air Pollutant Emission Factors" (AP-42) were used where possible.[2] For several commodities not listed in AP-42, emission factors available in Scott Environmental Technology's Inventory of Emissions From Marine Operations Within the California Coastal Waters were used.[3] These emission factors are based on data from actual emission tests. Emission factors for petroleum and coal products and for crude products were taken from Controlling Hydrocarbon Emissions From Tank Vessel Loading by the Marine Board of the National Research Council.[1] Table 2-1 lists the emission factors and their sources for each commodity category.

TABLE 2-1. VOC EMISSIONS FACTORS FOR CARGO LOADING

Commodity category	Commodity, No.(s)	Emission factors	
		Tankships, lb/1,000 gal	Barges, lb/1,000 gal
Gasoline	2911	1.80[2]	3.40[2]
Crude oil	1311	0.61[2]	1.00[2]
Crude oil	1311	3.1[a,1]	NA
Jet fuel	2912	0.50[4]	1.20[2]
Naphtha, solvents	2917	0.40[2]	0.80[b]
Alcohols	2813	0.50[3]	1.20[c]
Toluene	2817	0.40[c]	0.80[b]
Distillate fuel	2914	0.005[2]	0.005[3]
Chemicals[d]	2819, 2891	0.005[3]	0.005[3]
Others[e]	2911, 2811, 2861	0.005[1]	0.005[1]
Kerosene	2913	0.005[2]	0.013[2]

Note: Numbers by emission factors refer to references in the text.

[a]This emission factor is used solely for the terminal at Valdez, Alaska.
[b]Barge emission factor = twice the corresponding tankship emission factor.
[c]Estimated (see Section 2.2.1).
[d]Includes basic chemicals (Commodity No. 2819) and miscellaneous chemicals (Commodity No. 2891).
[e]Includes petroleum and coal products, crude products, and gum and wood chemicals (Commodity Nos. 2991, 2811, and 2861, respectively).

There are two sets of emission factors for crude oil. The higher emission factors apply solely to the terminal at Valdez, Alaska. Data provided by the State of Alaska and the terminal operating company (Alyeska) indicated that emissions associated with loadings at this facility were approximately four and a half times higher than originally estimated using emission factors from AP-42.[2,4] Crude oil at the Valdez terminal is loaded at a temperature near 38°C (100°F). It is thought that the temperature differential between the hot crude oil and the cool vessel causes convective cells to form inside the tank. These convective cells provide constant activity in the atmosphere inside the tank and may prevent a vapor blanket from forming on the liquid surface, thus increasing emissions. Because of the unique physical characteristics associated with crude oil loading at the Valdez terminal and to avoid a gross underestimation of emissions, the emissions for the Valdez terminal were estimated using the actual test data taken at the facility.[4]

For a few commodities, emission factors were available for tankship loading but not for barge loading. For those commodities having both emission factors available, the emission factors for barge loading are approximately twice the emission factors for tankship loading. Therefore, for those commodities where only tankship emission factors were available, the emission factors for barges were estimated by doubling the emission factors given for tankships. (The difference in emission factors between tankships and barges is due to differences in tank configuration. Tankship tanks are deeper and have less relative surface area per volume loaded than barges; consequently, a smaller percentage cargo evaporates.)[1]

Emission factors were estimated for those commodities that did not already have emission factors. Emission factors were not available for toluene and the alcohols category. The emission factors for toluene were estimated using the following loading loss equation provided in AP-42:[2]

Loading loss equation:

$$L_L = 12.46 \frac{SPM}{T} (1 - \frac{eff}{100}),$$

where:

S = saturation factor;

P = true vapor pressure, psia;

M = molecular weight;

T = temperature (°R); and

eff = control efficiency, percent.

The equation above was used to compare the loading losses calculated for toluene with the loading losses calculated for a commodity for which emission factors were available (i.e., benzene). If the variables S, T, and eff are assumed to be the same for both toluene and benzene, then the loading losses for these two commodities can be compared using values for molecular weight (M) and vapor pressure (P) as follows:

$$R = \frac{P_T M_T}{P_B M_B} = 0.29,$$

where:

R = ratio of toluene loading losses to benzene loading losses;

P_T = vapor pressure of toluene at 60°F = 0.3 psia;

P_B = vapor pressure of benzene at 60°F = 1.2 psia;

M_T = molecular weight of toluene = 92; and

M_B = molecular weight of benzene = 78.

Based on the ratio above, the emission factors for toluene were estimated to be about one quarter to one third those for benzene. (An emission factor for loading benzene into tankships equal to 1.5 pounds [lb] emitted per 1,000 gallons [gal] loaded was provided in the Scott document.[3] However, emissions from benzene loading are not included in the nationwide emissions estimate because they will be covered under a national emission standard for hazardous air pollutants [NESHAP] that will go into effect on March 7, 1992.)

Emission factors for alcohols were obtained by comparing the vapor pressure of methanol with the vapor pressures of other

commodities for which emission factors were available. The alcohols category includes 16 different alcohols and alcohol mixtures; information regarding the annual quantity of each type of alcohol loaded at marine terminals was not available. Therefore, methanol was chosen to represent alcohols because it has a high vapor pressure and represents a worst-case scenario for VOC emissions from loading alcohol. The vapor pressure of methanol is close to that of Jet Naphtha (i.e., jet fuel or JP4) over the temperature range from 10° to 21°C (50° to 70°F). Therefore, the emission factors for JP4 were applied as the emission factors for alcohols. A check on the validity of all emission factors was performed by comparing vapor pressures with emission factors.

2.2.1.2 HAP Emission Factors. A national estimate of HAP emissions was developed for all of the commodity categories in the WCUS data base except jet fuel and naphtha/solvents. Total HAP emissions associated with the commodity categories were estimated as a percentage of corresponding VOC emissions (based on available speciation data) for all categories. Table 2-2 presents the HAP emission factors used for the commodity categories.

Individual HAP emissions associated with loading gasoline, crude oil, distillate fuel, and kerosene was estimated based on the total quantity loaded (i.e., throughput), the total estimated VOC emissions, and speciation data showing the relative quantities of HAP's (e.g., benzene, toluene, hexane, etc.) present in the vapors of the commodities.[5] Toluene is a HAP and for this reason all emissions associated with the toluene category are HAP's.

Available speciation data for the jet fuel and naphtha/solvents categories did not include any HAP's.[6] Therefore, HAP emission factors for these two commodity categories are taken to be zero. Additional data regarding potential HAP's associated with these commodity categories are still being sought.

TABLE 2-2. HAP EMISSIONS FACTORS[a]

Commodity category	HAP	Emission factor for tankers, lb/1,000 gal	Emission factor for barges, lb/1,000 gal
Gasoline	Benzene	0.015	0.029
	Toluene	0.026	0.048
	Hexane	0.035	0.066
	Xylene	0.008	0.015
	Others	0.0033	0.0061
	Total	0.087	0.164
Crude oil[b]	Benzene	6.4×10^{-3}	0.010
	Toluene	4.3×10^{-3}	7.0×10^{-3}
	Hexane	0.067	0.11
	Xylenes	9.6×10^{-4}	1.6×10^{-3}
	Ethylbenzene	2.3×10^{-4}	3.7×10^{-4}
	Total	0.079	0.13
Crude oil[c]	Benzene	0.32	NA
	Toluene	0.022	NA
	Hexane	0.34	NA
	Xylenes	4.9×10^{-3}	NA
	Ethylbenzene	1.2×10^{-3}	NA
	Total	0.40	NA
Jet fuel		0	0
Naptha, solvents		0	0
Alcohols	Methanol Ethylene glycol	0.15	0.36
Toluene	Toluene	0.40	0.80
Distillate fuel	Xylene	7.5×10^{-5}	1.8×10^{-5}
	Benzene	3.9×10^{-5}	9.2×10^{-5}
	Toluene	3.3×10^{-5}	7.9×10^{-5}
	Ethylbenzene	2.0×10^{-6}	4.8×10^{-6}
	O-Xylene	2.5×10^{-6}	6.0×10^{-6}
	Total	8.4×10^{-5}	2.0×10^{-4}
Chemicals	All[d]	0.005	0.005
Others[e]	Xylenes	2.4×10^{-4} 1.2×10^{-4} 7.0×10^{-4} 4.3×10^{-4}	6.1×10^{-4} 3.1×10^{-4} 1.8×10^{-4} 1.1×10^{-3}
Kerosene	Hexane	2.4×10^{-4}	6.1×10^{-4}
	Benzene	1.2×10^{-4}	3.1×10^{-4}
	Toluene	7.0×10^{-5}	1.8×10^{-4}
	Total	4.3×10^{-4}	1.1×10^{-3}

[a]HAP emission factors are given in lb/1,000 gal to allow for easier comparison to VOC emission factors.
[b]HAP emission factors given are for all terminals except Valdez, Alaska.
[c]HAP emission factors given are for Valdez, Alaska, only.
[d]Approximately 60 of the 250 chemicals loaded onto marine vessels are HAP's. However, the worst-case assumption was made for this category and all chemicals emissions were presumed to be HAP's.
[e]Unspecified xylenes may be loaded under the crude products subcategory of "others."

The alcohols and chemicals commodity categories both represent more than one liquid, so estimating VOC and HAP emissions associated with these two categories requires that certain assumptions be made. The alcohols category includes 16 different alcohols and alcohol mixtures. Of these 16 compounds, two are on the list of 190 HAP's provided in Title III of the Clean Air Act Amendments (CAAA) of 1990.[7] These two compounds are methanol and ethylene glycol. Because the individual quantities of methanol and ethylene glycol loaded are not known, quantities loaded are estimated based on the amount of these two compounds produced relative to the annual production of the remaining 14 compounds in the alcohols category. The vapor pressures and molecular weights of methanol and ethylene glycol are also taken into account when estimating HAP emissions associated with the alcohols category (the vapor pressure of methanol is approximately 1,500 times that of ethylene glycol).[7]

The chemicals category includes over 250 different chemicals, and, of these 250, approximately 60 also appear on the list of 190 HAP's provided in Title III of the CAAA of 1990.[7] Because the individual quantity of each chemical loaded was not known, and due to the large number of chemicals, the worst-case assumption was made and the entire throughput associated with the chemicals category was used to estimate HAP emissions for the chemicals category.

The "others" commodity category includes "crude products." A list of compounds included in the crude products subcategory revealed that some crude products (e.g., miscellaneous xylenes) are HAP's.[8] Therefore, all emissions associated with the throughput of crude products are considered HAP's to avoid underestimating the potential HAP emissions from this category. Neither of the remaining two subcategories in the others category include HAP's.

Emissions of HAP's associated with the distillate fuel and kerosene categories were estimated based on speciation data obtained from EPA's VOC/PM Speciate data base.[6]

2.2.2 Cargo Loading Emissions

2.2.2.1 VOC Emissions. Cargo loading VOC emissions were calculated for each commodity category using the quantity (i.e., throughput) of the commodity loaded (in tons), the appropriate emission factor, and the density of the cargo (in tons per 1,000 gallons). Emissions of VOC's were calculated according to the following equation:

$$E_V = (c/d) \times f,$$

where:

E_V = mass of VOC emissions;
c = mass of the cargo (commodity);
d = density of the cargo (mass per unit volume); and
f = commodity-specific emission factor (mass per unit volume).

Emissions from cargo loading were estimated for each of the 1,648 terminals in the data base based on the quantity (throughput) of each commodity loaded at each terminal and the equation above. For a terminal loading more than one commodity, the emissions associated with each commodity were calculated separately and then summed to determine the total emissions for that terminal. The sum of the emissions from the 1,648 terminals in the data base represents the estimated nationwide annual emissions from cargo loading.

The cumulative national VOC emissions from cargo loading are estimated to be 75,200 megagrams per year (Mg/yr) (1.7×10^8 pounds per year [lb/yr]). Crude oil is the major source of emissions at 49,300 Mg/yr (1.1×10^8 lb/yr) (66 percent of all emissions). One facility (at Valdez, Alaska) accounts for 39,000 Mg/yr (8.6×10^7 lb/yr) of total estimated crude oil emissions (i.e., 79 percent of estimated annual crude oil emissions and 52 percent of total estimated annual VOC emissions.) Gasoline is the second largest source of emissions, contributing 21,900 Mg/yr (4.8×10^7 lb/yr) (29 percent of all emissions). Nationwide emissions may be overstated because emissions from some commodity categories (e.g., alcohols) were

estimated based on worst-case assumptions. As stated in Chapter 1, terminals that are affected by promulgated State or local regulations requiring control of marine vessel loading emissions have been identified in the data base. Table 2-3 shows nationwide emissions for the current data base (i.e., with controlled emissions removed). However, nationwide emissions shown in Table 2-4 are estimated based on the assumption that all emissions are uncontrolled. Approximately 19 percent of the total estimated VOC emissions shown in Table 2-4 are already subject to control under promulgated State regulations.

2.2.2.2 HAP Emissions. Cargo loading HAP emissions were calculated for five commodity categories using the mass quantity of VOC emissions and the percentage of VOC emissions estimated to be HAP's. The following equation was used to calculate HAP emissions.

$$E_H = E_V \times p,$$

where:

E_H = mass of HAP emissions;

E_V = mass of VOC emissions; and

p = mass percent of vapor comprised by HAP's.

Emissions of HAP's from cargo loading were estimated for all terminals. The sum of these HAP emissions represents the estimated nationwide annual HAP emissions from cargo loading. Table 2-5 shows estimated annual HAP emissions from cargo loading by commodity for terminals in the current data base.

The cumulative national HAP emissions from cargo loading were estimated to be 7,947 Mg/yr (1.75×10^7 lb/yr). Like the nationwide VOC emission estimates, the HAP emission estimates do not include emissions already subject to promulgated State regulations. Also, HAP emissions may be overstated because the entire throughput of the chemicals category was used to calculate HAP emissions from that category and some chemicals may actually be loaded in containers.

Gasoline and crude oil are the major sources of HAP emissions at 1,054 Mg/yr (2.3×10^6 lb/yr) and 6,346 Mg/yr (1.4×10^7 lb/yr), respectively. Of the 6,346 Mg/yr of HAP

TABLE 2-3. ANNUAL VOC EMISSIONS BY COMMODITY (CONTROLLED EMISSIONS EXCLUDED)

Commodity	Commodity No.	Emission factor for tankers, lb/1,000 gal	Emission factors for barges, lb/1,000 gal	Density, tons/1,000 gal	Tanker emissions estimate, Mg/yr	Percentage of tanker emissions, percent	Barge emissions estimate, Mg/yr	Percentage of barge emissions, percent	Total emissions estimate, Mg/yr	Percentage of total emissions, percent	Ballasting emissions, Mg/yr
Gasoline	2911	1.800	3.400	3.125	3,640	7.47	18,200	69.0	21,900	27.08	--
Crude oil[a]	1311	0.610	1.000	3.620	44,600	91.44	4,710	17.85	49,300	65.59	950
Jet fuel	2912	0.500	1.200	3.075	275	0.56	1,409	5.34	1,680	2.24	--
Naphtha, solvents	2917	0.400	0.800	3.100	105	0.21	906	3.43	1,011	1.34	--
Alcohols	2813	0.500	1.200	3.305	101	0.21	838	3.18	940	1.25	--
Toluene	2817	0.400	0.800	3.614	20	0.04	218	0.82	238	0.32	--
Dist. fuel	2914	0.005	0.012	2.792	16	0.02	79	0.30	95	0.13	--
Chemicals[b]		0.005	0.005	3.750	12	0.03	15	0.06	27	0.04	
Others[c]		0.005	0.005	3.464	1.0	0.00	4.7	0.02	5.7	0.01	--
Kerosene	2913	0.005	0.013	3.375	0.4	0.00	2.4	0.01	2.8	0.00	--
TOTAL					48,800	100	26,400	100	75,200	100	

[a]Approximately 76 percent of annual estimated crude oil emissions are attributed to one terminal (Valdez)
[b]Includes "Basic Chemicals" (Commodity No. 2819) and "Miscellaneous Chemicals" (Commodity No. 2891).
[c]Includes "Petroleum and Coal Products," "Crude Oil Products," and "Gum and Wood Chemicals" (Commodity Nos. 2991, 2811, and 2861, respectively).

TABLE 2-4. ANNUAL VOC EMISSIONS BY COMMODITY (CONTROLLED EMISSIONS INCLUDED)

Commodity	Commodity No.	Emission factor for tankers, lb/1,000 gal	Emission factors for barges, lb/1,000 gal	Density, tons/1,000 gal	Tanker emissions estimate, Mg/yr	Percentage of tanker emissions, percent	Barge emissions estimate, Mg/yr	Percentage of barge emissions, percent	Total emissions estimate, Mg/yr	Percentage of total emissions, percent	Ballasting emissions, Mg/yr
Gasoline	2911	1.800	3.400	3.125	5,850	11.3	31,500	76.8	37,300	40.0	-
Crude oil[a]	1311	0.610	1.000	3.620*	45,200	87.4	5,740	14.0	51,500	55.2	950
Jet fuel	2912	0.500	1.200	3.075	378	2.98	1,650	4.03	2,030	2.18	--
Naphtha, solvents	2917	0.400	0.800	3.100	105	0.82	906	2.21	1,010	1.08	--
Alcohols	2813	0.500	1.200	3.305	109	0.86	868	2.12	978	1.05	--
Toluene	2817	0.400	0.800	3.614	20	0.16	218	0.53	238	0.26	--
Dist. fuel	2914	0.005	0.012	2.792	16	0.13	79	0.19	95	0.10	--
Chemicals[b]		0.005	0.005	3.750	12	0.10	15	0.04	27	0.03	--
Others[c]		0.005	0.005	3.464	1	0.01	5	0.01	6	0.006	--
Kerosene	2913	0.005	0.013	3.375	0	0.00	2	0.01	3	0.003	--
TOTAL					51,700	100	41,000	100	93,200	100	--

[a]Approximately 76 percent of annual estimated crude oil emissions are attributed to one terminal (Valdez)

[b]Includes "Basic Chemicals" (Commodity No. 2819) and "Miscellaneous Chemicals" (Commodity No. 2891).

[c]Includes "Petroleum and Coal Products," "Crude Oil Products," and "Gum and Wood Chemicals" (Commodity Nos. 2991, 2811, and 2861, respectively).

TABLE 2-5. HAP EMISSIONS ESTIMATES

Commodity	HAP	Mass percent of HAP's	HAP emissions, Mg/yr
Gasoline	Benzene	0.80	184
	Toluene	1.17	312
	Hexane	1.49	421
	Xylene	0.46	97
	Others[a]	0.90	40
	Subtotal	4.82	1,054
Crude oil	Benzene	1.05	108
	Toluene	0.70	72
	Hexane	10.93	1,125
	Xylene	0.16	16
	Ethylbenzene	0.04	4
	Total	12.87	1,325
Crude oil (Valdez)	Benzene	1.05	408
	Toluene	0.70	272
	Hexane	10.93	4,264
	Xylenes	0.16	62
	Ethylbenzene	0.04	15
	Total	12.87	5,021
Jet fuel	All	0	0
Naphtha, solvents	All	0	0
Alcohols	Methanol, ethylene glycol	30	282
Toluene	Toluene	100.	238
Distillate fuel	Xylene	0.15	0.14
	Benzene	0.77	0.73
	Toluene	0.66	0.63
	Ethylbenzene	0.04	0.04
	O-xylene	0.05	0.05
	Subtotal	1.67	1.59
Chemicals	All	100	27
Others	All	29.05	1.66
Kerosene	Hexane	4.7	0.13
	Benzene	2.4	0.07
	Toluene	1.4	0.04
	Subtotal	8.5	0.24
Total	All		7,947

[a]Includes cumene, naphthalene, ethylbenzene, and isooctane. Source: Reference 5.

emissions associated with crude oil, 5,020 Mg/yr (1.1 x 10^7 lb/yr) are attributable to the terminal at Valdez, Alaska, alone. This is primarily due to the extremely high throughput and elevated emission factors associated with this facility.

Emissions of HAP's associated with the loading of all of the commodity categories except gasoline and crude oil comprise less than one-third of total HAP emissions. Toluene emissions associated with cargo loading are equal to the VOC estimate of 238 Mg/yr (5.2 x 10^5 lb/yr). (All vapors from toluene loadings are HAP's.) The two compounds responsible for HAP emissions associated with the alcohols category are methanol and ethylene glycol. The total estimated HAP emissions of methanol and ethylene glycol are 282 Mg/yr (6.2 x 10^5 lb/yr) and 0.4 Mg/yr (882 lb/yr). Approximately 60 of the 250 different chemicals in the "chemicals" category are HAP's.[7] Since the different throughputs and emission factors were not known for each chemical, the worst-case assumption was made and the entire chemicals throughput was assumed to be HAP's. For this reason, VOC and HAP emissions are the same for the chemicals category at 27 Mg/yr (6 x 10^5 lb/yr).

Emissions of HAP's associated with loading distillate fuel and kerosene are very low, due primarily to their low VOC emission factors. Total HAP emissions associated with distillate fuel loadings are 1.6 Mg/yr (3.5 x 10^3 lb/yr). Total HAP emissions from kerosene cargo loadings are 0.24 Mg/yr (529 lb/yr).

2.3 TANKSHIP BALLASTING

Tankship ballasting emissions were estimated using the annual quantities of cargo unloaded, the density of the cargo, the percentage of ballast water loaded, the fraction of ships using cargo tanks for ballast, and a ballasting emission factor. The following equation was used to calculate ballasting emissions:[1]

$$E_B = (c/d) \times P \times 0.30 \times f,$$

where:

E_B = mass of VOC emissions from ballasting;

c = mass of cargo;

d = density of commodity (mass per unit volume);

P = percentage of tankships without equipment to prevent ballasting emissions; and

f = commodity-specific emission factor (mass per unit volume).

The data base contains unloading information only for crude oil; no information was obtained regarding the unloading of other commodities. Therefore, nationwide ballasting emissions were calculated only for crude oil. However, crude oil represents the majority of VOC-emitting compounds unloaded at marine terminals (approximately 76 percent of the nationwide ballasting emissions estimated by the Marine Board for 1984 were attributed to crude oil). The percentage of tankships without equipment to prevent ballasting emissions was assumed to be 5.2 percent, based on information provided by the Marine Board.[1] A tankship ballasting emission factor of 1.2 lb/1,000 gallons of crude oil unloaded was provided in AP-42.[2] Approximately 30 percent of the volume of the tank was assumed to be filled with ballast water.[1] Based on these assumptions and no clean ballast tanks, the total VOC emissions from crude oil tankship ballasting were estimated to be approximately 950 Mg/yr (2.1×10^6 lb/yr). Based on the portion of HAP's in crude oil vapor, total HAP emissions from ballasting are 120 Mg/yr (2.7×10^5 lb/yr). Benzene accounts for 9.9 Mg/yr (2.2×10^4 lb/yr) of HAP emissions from crude oil tankship ballasting, and toluene accounts for 6.6 Mg/yr (1.5×10^4 lb/yr). Hexane accounts for the largest portion of HAP emissions from crude oil tankship ballasting 104 Mg/yr (2.3×10^5 lb/yr). Ballasting emissions will diminish in the future because most tankships built since 1980 are required by domestic law and

international agreement to use segregated ballast tanks (SBT's) and, thus, do not emit vapors during ballasting.[1]

2.4 EMISSION CONTROLS

This section describes the types of emission control systems available for controlling VOC and HAP emissions from marine vessel loading operations. The information contained in this section is taken primarily from Chapter 3 of the Marine Board's Controlling Hydrocarbon Emissions From Tank Vessel Loading.[1]

Several emission control processes are applicable to controlling emissions during marine vessel loading; these processes fall into two major categories: combustion and recovery. Combustion processes include flares and incinerators. Recovery processes include lean oil absorbers, refrigeration systems, and carbon-bed adsorbers. All of these vapor control systems are described below. However, incineration was assumed to be the control method of choice when estimating the costs of control in Chapter 3 of this document. The primary reason for selecting incineration is that many marine terminals load more than one commodity, and recovery processes are best suited to terminals that load only one commodity. When selecting a vapor control system for an actual terminal, the decision of whether or not to recover the commodity also depends on (1) the nature of the VOC stream (specifically, its expected variability in flow rate and hydrocarbon content) and (2) locational factors, such as the availability of utilities and the distance from the tankship or barge to the vapor control system.[1]

Compared to recovery processes, flares and incinerators are inexpensive to install and easy to operate. Combustion systems tend to be well suited to low-volume terminals that are located far from existing utility hookups. Combustion processes are more economic than other control technologies if the VOC vapor vented from the tankships and tank barges is lean and the potential value of the recovered VOC is low. Conversely, if the VOC stream is relatively rich and the terminal has a high throughput, adequate space, and easily accessible utilities, then it may be economic to recover the VOC. Recovery systems are more expensive

to install and operate than combustion systems; however, the value of the recovered VOC can make recovery cost effective.[1]

2.4.1 Closed Loading of Vessels

Controlling emissions from tank vessel loading requires that the compartments on both tankships and barges be closed to the atmosphere during loading. Closed loading is done with hatches and ports closed, but it does not necessarily preclude venting vapors to the atmosphere (tank vents are generally open to the atmosphere). Most tankships are already equipped for closed loading as a result of having inert gas systems on board (closed loading is necessary to maintain the legally required minimum inert gas pressure in the cargo tanks).[1] Barges generally do not use inert gas, so they are usually open loaded. Equipment necessary for closed loading includes (1) devices to protect tanks from underpressurization and overpressurization, (2) level-monitoring and alarm systems to prevent overfilling, and (3) devices for cargo gauging and sampling.[1] The types of equipment included in each of these three categories is explained in detail in the Marine Board document.[1]

2.4.2 Combustion Processes

The combustion processes described in this section include flares (both open and enclosed) and incinerators (recuperative and regenerative). Flares and incinerators combust VOC vapors as they arrive from the vessel or from intermediate vapor-recovery equipment. The combustion products are mainly carbon dioxide (CO_2) and water; small amounts of nitrous oxides (NO_x) and carbon monoxide (CO) are also produced. Both flares and incinerators are more than 98 percent efficient if operated properly.

The primary drawback to using combustion processes is that they do not recover the VOC and use fuel in the process. Also, incinerating chlorinated compounds may lead to the formation and emission of acid gases. Another drawback is that combustion devices are potential ignition sources. However, newly manufactured combustion devices have flame arresters to guard against flash back. This concern is especially important if the displaced vapors are not inerted or enriched. Vapors from

vessels with inert gas systems have oxygen contents below 8 percent, which is too low to support combustion. The lack of oxygen greatly reduces the risk of explosion; however, it also requires the combustion system to draw in additional air (to raise oxygen levels to the point where the mixture will burn). Diluting the vapors increases the size of the combustor and the amount of supplemental fuel needed to maintain minimum combustion temperatures.[1] Enrichment of vapors involves adding fuel (usually methane or propane) to the VOC mixture to make it too rich to support combustion.

The primary advantage of using combustion instead of recovery systems is that combustion devices are generally cheaper to install and to operate. Combustion processes are also more efficient than recovery processes in reducing the VOC content of the vapor stream. In addition, combusting VOC's is more practical at terminals where several different commodities are loaded. (For additional information on combustion processes, see Chapter 3 of the Marine Board document).[1]

2.4.2.1 Flares. Flares combust VOC's by igniting the VOC-laden vapors as they pass through one or more burners. Flares may be either open or enclosed. An enclosed flare is of the same fundamental design as an open flare but with a protective cylindrical shroud around the burners. Enclosed flares allow for control of operating temperature and residence time as well as emission testing. Flares are the least expensive control system. Flares require little operator attention and will burn on their own so long as the incoming vapors contain enough hydrocarbon. Pilot burners are used to ensure that a flame is maintained in the event that the main flame goes out; the pilot burner is much smaller than the primary burners. Flares are usually more than 98 percent efficient as long as the combustion zone stays properly lighted. Flares, especially open ones, need to be located away from people and equipment for safety reasons.[1]

2.4.2.2 Incinerators. Incinerators operate by combusting VOC vapors in a confined chamber under controlled conditions.

Vapors enter the reaction chamber, combust, and then exit through an exhaust stack. Supplemental combustion air and fuel are added to the reaction mixture to maximize combustion efficiency.[1] Combustion air is added to maintain an excess of oxygen, and supplemental fuel is added to maintain the desired operating temperature.

There are two basic designs of incinerators: recuperative and regenerative. Regenerative incinerators differ from recuperative incinerators in that they have heat-exchange media upstream and downstream of the reaction chamber. By periodically reversing the flow direction, regenerative incinerators can recover more energy than a recuperative incinerator equipped with a heat exchanger.[9]

When outfitted with a heat exchanger, recuperative incinerators can achieve up to 70 percent energy recovery. High destruction efficiencies (99+ percent) can be achieved by operating at higher temperatures or by increasing the residence time (via a larger combustion chamber), both of which result in increased fuel consumption. Recuperative incinerators are better suited to lower flows and richer gas streams more capable of supporting their own combustion.[9]

Regenerative incinerators operate in much the same way as recuperative incinerators with heat exchangers. Regenerative incinerators, however, have direct-contact beds of silica gravel or ceramic burls that absorb heat from the exhaust gas. Periodically, the direction of the gas flow through the incinerator is reversed. The bed that was being heated by the exhaust gas now preheats the incoming stream. By using this method of direct-contact heat exchange and reversing flow, energy recovery can be up to 95 percent efficient. Control efficiencies of up to 99 percent destruction can be achieved. The high-energy recovery makes regenerative incinerators well suited to lean, high-volume gas streams. In many cases, the pilot burner alone will supply the heat input necessary to maintain combustion.[9]

The incinerator costs presented in Chapter 3 of this document were estimated based on the assumption that regenerative incinerators will be used to control loading emissions.

Regenerative incinerators were used in the estimates in order to better utilize the Marine Board costs. The incinerator and fuel costs in the Marine Board estimate indicated that a regenerative incinerator was used. Marine Board costs also assumed that vapors would be inerted prior transport to the incinerator. However, marine vessel loading is a batch process, and would require constant startup and shutdown of the incinerator or idling, which would raise fuel consumption. Because of this, most combustion systems will likely use a recuperative incinerator or enclosed flare and an enrichment system. This system would be slightly less complex and more streamlined than the one used by EPA for costs estimates.

2.4.3 Recovery Processes

Recovery processes are more complex to design and operate than are combustion processes; however, the value of the recovered product can make recovery a feasible alternative in some cases. Most recovery processes can recover 80 to 95 percent of the VOC with moderate installation and operating costs. Achieving higher efficiencies can be very costly because severe operating conditions are required (e.g., temperatures below -200°F or pressures above 250 psia). If further reduction of VOC's is needed, a small flare or incinerator can follow the recovery unit and polish the outlet stream.[1]

The recovery processes described in this section include lean oil absorption, refrigeration, and carbon bed adsorption.

2.4.3.1 Lean Oil Absorption. Lean oil absorbers use condensation and cooling under pressure to transfer hydrocarbons (VOC's) from a rich vapor into a lean oil. Any hydrocarbon liquid with sufficiently low vapor pressure can be used as the lean oil. Tankship- and barge-loading terminals could use crude, product, or another specially designated lean oil supply. The recovered hydrocarbon can be either incorporated and sold as part of the lean oil or stripped from it and handled separately. When

possible, the same commodity being loaded should be used as the lean oil supply because it will work well and saves the added expense of another material. The commodity can then be returned to a storage tank or to the vessel being loaded.

Lean oil absorption processes are very efficient at recovering hydrocarbon from rich streams but much less efficient at removing hydrocarbon from lean streams that contain little hydrocarbon. Lean oil absorbers usually operate at pressures of 100 to 200 psia. To further reduce the existing vapor's hydrocarbon content, some absorption units also cool the lean oil. Typically, an absorber can remove 80 to 90 percent of a vapor's hydrocarbon by simply increasing the pressure. Efficiencies of up to 95 percent can be achieved by lowering the operating temperature as well. However, at temperatures much below 60°F, hydrate formation may cause freeze-up problems. If the system is under pressure, water can freeze, even at temperatures above 32°F. If necessary, antifreeze (e.g., ethylene glycol) can be used to lower the liquid hydrocarbon's freezing point.[1]

2.4.3.2 Refrigeration. Direct refrigeration systems remove hydrocarbons by cooling the vapors through a series of low-temperature heat exchangers. These systems are best suited to vapors from non-inerted product carriers, i.e., vapors that do not contain as much CO_2, light ends, or corrosion-causing contaminants, such as hydrogen sulfide (H_2S). (Inerted vapors contain about 15 percent CO_2 by volume; H_2S is contained in crude oil vapors.)[1]

Most direct refrigeration systems use sea or river water to cool the vapors to around 60°F. This step removes most of the water and heavy hydrocarbons from the vapor. Next, as many as four refrigeration loops cool the remaining vapor to somewhere in the -100° to -150°F range. The number of loops needed and the intermediate operating temperatures depend on the hydrocarbon (VOC) species present and the desired recovery efficiency. Usually the first heat exchanger removes water from the vapor at

around 32°F, the second heat exchanger cools the vapor to below 0°F to remove intermediate-weight hydrocarbons, and so on.[1]

To further improve hydrocarbon reduction, it is useful to compress the vapors, further reducing the equilibrium hydrocarbon content. Compression is usually done after the first or second exchanger, at which point most of the water and heavy hydrocarbons have been removed. After the vapor has passed through the low-temperature heat exchangers, it expands and reaches ambient pressure as it is vented to the atmosphere. This expansion lowers the temperature further and drops out additional hydrocarbon.

Direct refrigeration can remove up to 99 percent of a stream's VOC content when very low temperatures are used. However, below 60°F, hydrates may form and plug heat exchanger surfaces and lines. Hydrate formation may be avoided by injecting ethylene glycol or other antifreeze or by operating the refrigeration unit intermittently to allow periodic thawing. However, using antifreeze becomes very expensive at lower operating pressures, and intermittent operation may limit loading rates on tankships and barges.[1]

2.4.3.3 Carbon Bed Adsorption. Carbon bed adsorbers use activated carbon or a similar adsorptive medium to adsorb hydrocarbons selectively. Air and very light hydrocarbons pass through the medium, while heavier hydrocarbons are adsorbed to the medium's surface. Carbon beds operate effectively regardless of whether or not the incoming vapors have been inerted. However, by Coast Guard regulation, vapors routed to a vapor recovery unit need not be enriched, inerted, or diluted.[10] After the capacity of the adsorptive medium is used up--that is, after most of the adsorptive sites are already holding hydrocarbons--hydrocarbons will "break through" and appear in increasing amounts in the exiting vapor. At this time, the medium needs to be recharged, or the exiting vapor will eventually contain as much hydrocarbon as the untreated vapor, and the pressure drop across the adsorption unit may become unacceptable.[1]

Although disposal of spent carbon is an option, most terminals are large enough for activated carbon regeneration to be economical. The best method for regenerating the spent carbon is to use a vacuum pump to desorb the hydrocarbons. Another alternative, steam stripping, requires a steam source and generates an oily wastewater stream that requires proper disposal.[1]

Carbon bed adsorbers can be more than 99 percent effective at removing hydrocarbons; however, carbon beds are not as effective at removing light ends such as ethane and propane. Such light species tend to adsorb poorly, and slight temperature increases may drive them off. Alternatively, when heavier, more strongly attracted species pass through the bed, they may displace the lighter species from the active sites. Also, H_2S and other contaminants present in crude oil and other "dirty" commodities permanently poison activated carbon. Poisoning of the activated carbon can be avoided, however, by treating the vapor with caustic (sodium hydroxide) prior to routing the vapor to the adsorber.[1]

2.5 CURRENT PRACTICES AND SAFETY ASPECTS

The technology for controlling VOC and HAP emissions from marine vessel loading operations is available and already in use on vessels and at marine terminals that load highly toxic or noxious cargoes with volatile vapors, such as ammonia, chlorine, acrylonitrile, and epichlorohydrin. These and other hazardous fluids are routinely captured for reuse or disposal.[1] Applying these control technologies to terminals with high throughputs and loading rates (typical of terminals that load gasoline and crude oil) will require that terminal operators maintain safe operating practices due to the increased handling of potentially explosive vapors.

Loading the tank vessels with hydrocarbon cargoes presents three main hazards: (1) fire due to the ignition of spilled liquid or unconfined vapors, (2) explosion due to the ignition of vapor-air mixtures in confined spaces, and (3) water pollution as a result of spills. Adding vapor-handling systems could increase

the risks of such events occurring by adding to the operational complexity of loading operations, and in particular by requiring additional handling of potentially explosive vapors. An additional consideration is the possible personnel exposure to vapors. However, the risks associated with vapor control can be minimized through proper personnel training and management. Also, redundant safety systems are required at terminals and on board vessels to ensure that the temporary failure of one system would not expose operations to undue risks.[1] The U.S. Coast Guard has addressed these safety issues by adopting new regulations for the safe design, installation, and operation of marine vapor control systems; these regulations became effective on June 21, 1990.[10]

2.6 REFERENCES FOR CHAPTER 2

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3.0 COSTS

This chapter presents the estimated capital and annual costs of controlling emissions from marine vessel loading operations. These costs include the costs of retrofitting both the marine terminals and the vessels that load at these terminals. Section 3.1 discusses the model terminals and vessels that were developed in order to simplify the cost-estimating procedures. The capital and annual costs of retrofitting the model vessels is discussed in Section 3.2; Section 3.3 presents the capital and annual costs of retrofitting the model terminals with an incineration system or a carbon adsorption system. Nationwide costs are discussed in Section 3.4.

3.1 DEVELOPMENT OF MODEL TERMINALS AND VESSELS

3.1.1 Background

In April 1987, the Marine Board of the National Council on Engineering and Technical Systems (Marine Board) contracted with United Technical Design, Inc. (UTD) to prepare a cost estimate for marine vapor control systems. The Marine Board provided UTD with four model vessels and three model terminals. The four model vessels are (1) a crude oil tankship (70 kilo dead weight tons [kdwt]), (2) a product tankship (35 kdwt), (3) a crude-oil ocean barge (19 kdwt), and (4) an inland river barge. The three model terminals are (5) a product terminal serving inland river barges, (6) a crude oil terminal, and (7) a product terminal serving ships and barges. The numbers preceeding the individual model descriptions correspond to the Marine Board model number.

United Technical Design estimated the cost of installing an incineration-based emissions control system at each of the three model terminals, as well as the cost of retrofitting the model

vessels (i.e., tankships and barges) loaded at those terminals. Equipment needed for vessel retrofit includes systems aboard vessels that make closed loading possible: devices to protect tanks from overpressurization, level monitoring and alarm systems to prevent overfilling, and devices for final cargo gauging and sampling. Vessels need piping and manifolds to collect vapors and carry them ashore for disposition. Tank gauging and alarms, detonation arrestors, and other safety devices on vessels and at terminals are needed to prevent overpressurization and prevent fires and explosions.

3.1.2 New Models

The three Marine Board model terminals are designed for throughputs of 8 million barrels per year (mm bbl/yr), 70 mm bbl/yr, and 29 mm bbl/yr, respectively (based on loading one vessel 2,000 hours per year at maximum capacity). However, the majority (1,348 out of 1,648) of the terminals in the current data base have throughputs of less than 1 million bbl/yr. To better represent actual terminals, the existing three model terminals were modified to create eight model terminals. Most of the new model terminals are designed with lower throughputs than the original models and more closely parallel the throughputs of VOC-emitting commodities at actual terminals. The model vessels used are the same as those created by the Marine Board.

In order to estimate terminal costs, each terminal represented in the data base was assigned to one of the eight model terminals. The actual terminals were assigned to model terminals based on the commodities loaded (product or crude oil), vessels loaded (barge or ship), and throughput (bbl/yr). (Product is defined as any commodity other than crude oil.) Table 3-1 presents a brief summary of the eight model terminals and shows the number of actual terminals represented by each model. The four model vessels are presented in Table 3-2.

Terminals assigned to Models 6A, 6B, and 6C load crude oil only. Terminals assigned to other models load at least one product commodity and may or may not also load crude oil. Models 5A, 5B, and 5C are based on Marine Board Model Terminal 5

and represent terminals that load product commodities onto barges only. Models 7A and 7B are based on Marine Board Model Terminal 7 and represent terminals that load product commodities onto either ships only or both ships and barges. Model 6A is based on Marine Board Model Terminal 6 and represents terminals that load crude oil onto ships or ships and barges. Models 6B and 6C are based on Marine Board Model Terminal 5 and represent terminals that load crude oil onto barges only. A detailed description of the four model vessels and eight new model terminals is provided in Appendix A.

3.2 MODEL VESSELS

The Marine Board developed four model vessels for use with the model terminals.[1] The model vessels are (1) a crude oil tankship (70 kdwt), (2) a product tankship (35 kdwt), (3) a crude-oil ocean barge (19 kdwt), and (4) an inland river barge. The characteristics of the four model vessels and associated retrofit costs are presented in Table 3-2.

The capital costs for the model vessel retrofits are taken from the UTD cost estimate.[2] The UTD model vessel costs differ from the Marine Board costs only for Model Vessel 2, 35 kdwt product ships. The Marine Board wholly adopted UTD's cost estimates with the exception of Model Vessel 2. The Marine Board estimate includes shipboard inert gas generators while UTD's estimate does not. The UTD estimate is used for Model Vessel 2, as dock-mounted inert gas generators are more economical than those mounted shipboard.

Model Vessel 3 is a 19 kdwt crude oil ocean barge. It is not used by any of the Marine Board or modified model terminals. Terminals that load crude oil onto barges and terminals that load products onto ships are both assumed to use inland river barges.

The capital costs for vessel retrofit range from $168,000 to $426,000, depending upon vessel size and existing piping.[2] The capital costs to retrofit Model Vessels 1 and 4 are the same ($168,000). Model Vessel 1 has an inert gas system onboard, the piping of which can be used as a vapor collection header. Model Vessel 4 requires a complete retrofit (i.e., piping,

instrumentation, hardware), the cost of which may exceed the value of the vessel. The capital cost to retrofit Model Vessel 2 (35 kdwt product ship) is highest. It is the largest vessel that requires a complete retrofit.

Annual costs for vessel retrofit range from $24,500 to $64,400 per year.[2] The annual costs depend upon the amount of maintenance the vessel retrofit will require and recovery of the capital invested in the retrofit. The annual costs also are taken directly from the UTD cost estimate. A complete summary of vessel retrofit capital and annual costs is presented in Table 3-3.

3.3 MODEL TERMINAL COSTS

3.3.1 Capital Costs

The capital costs for each of the model terminals are dictated by the number of berths (number of vessels that can simultaneously load at the terminal) and the maximum loading rate. The number of berths at each terminal affects the amount of equipment and piping necessary for controlling emissions; the maximum loading rate affects the size of the necessary equipment and piping. Maximum loading rates for each model terminal may be calculated by multiplying the number of berths by the loading rates of the associated model vessels.

Models Terminals 5A, 5B, and 5C are designed to load four barges, two barges, and one barge, respectively (no tankships are associated with these models). Each barge has a loading rate of 4,000 barrels/hour (bbl/hr). Therefore, the equipment and piping must be sized to handle 22,460 ft^3 (4,000 bbl/hr x 5.615 ft^3/bbl) of VOC gas stream per barge, plus the inert gas (if necessary) to inert the VOC stream. A ratio of 1.37 ft^3 inert gas to 1 ft^3 VOC's is used to determine the gas flow rate when incineration is used. This ratio, which is higher than the industry standard 125 percent assumed in the UTD estimate, is calculated as the amount of inert gas necessary to dilute gasoline (Reid Vapor Pressure = 7) at 70°F to 8 percent oxygen. Maximum output from the inert gas generator for Models Terminals 5A, 5B, and 5C is 30,770 ft^3/hr (1.37 x 22,460 ft^3) per

barge. Maximum flow to the incinerator for these models is then 30,770 ft^3/hr + 22,460 ft^3/hr, or 53,230 ft^3/hr (887 ft^3/min) per barge when incineration is used. No inert gas or dilution air is assumed for recovery. Model gas stream flows for other terminal scenarios are calculated similarly.

Gas stream flows are important for determining both capital and annual costs. Incinerator, inert gas generator, and piping costs are all flow dependent. Annual costs, such as natural gas and electricity are also dependent upon vapor flow rates.

3.3.1.1 Incineration. The approach used in original cost analysis prepared by UTD, "Scoping Quality Cost Estimate for Marine Vapor Control Systems," is used as the cost basis for applying an incinerator to the eight model terminals. However, the methodology for many capital and annual costs has been changed from the original estimate. Incinerator, equipment, piping and instrumentation costs have all been changed to reflect the loading rates and numbers of vessels assigned to the new model terminals. Additionally, costs were developed for an independent inert gas generator and scrubber water system because the system used in the UTD cost estimate is not technically feasible. The original UTD cost estimate assumed that incinerator exhaust gas would be used as an inert gas to dilute vapors as they were displaced during loading. Regenerative incinerators require large amounts of excess air to achieve high (98 percent) destruction efficiencies.[3] When operating with high levels of excess air, the exhaust gas contains too much oxygen to be used as an inert gas. If excess air levels are decreased to stoichiometric levels (no excess air) in an effort to reduce exhaust gas oxygen content, destruction efficiency is reduced to 70 to 80 percent.[4] Therefore, separate inert gas generators mounted dockside are included in the cost estimate. The advantage of a regenerative incinerator is that no auxiliary fuel is needed due to the high stream concentrations and energy recovery of the incinerator. The only uses for auxiliary fuel would be startup, idling, and maintaining the pilot light.

The inert gas generator must be capable of supplying inert gas for the loading of all the vessels utilized by a model terminal. The use of one inert gas generator for Model Terminals 5A to 5C, 6B, and 6C is practical. However, if a single inert gas generator were sized to handle the loading of all vessels associated with models 7A or 7B, its turndown ratio (i.e., minimum operating capacity divided by maximum operating capacity) is great enough that it would over-produce inert gas during the loading of a single barge. For this reason and for greater reliability, multiple inert gas generators were assumed in lieu of one full-sized inert gas generator for Model Terminals 7A and 7B.

A separate inert gas system was assumed for all models except Model Terminal 6 (the vessels associated with Model Terminal 6 have their own inert gas systems). The inert gas generator costs are adjusted for size using EPA costing methodology.[5,6] Inert gas generator costs range from $63,000 to $684,000 per model.

Incinerator capital costs provided by UTD were changed to reflect EPA costing methodology.[5] New incinerator costs range from $218,000 to $368,000. An additional 33 percent was added to the incinerator cost for installation. Installed incinerator costs range from $290,000 to $490,000. The original UTD installed incinerator costs ranged from $319,000 to $1,600,000. The difference between the costs estimated using UTD and EPA methodologies is greatest between Model Terminal 7A and the Marine Board's Model Terminal 7.

The UTD costs for other major equipment and instrumentation are used directly. However, the UTD estimates of some items in these categories (e.g., trip valves, detonation arrestors, oxygen probes) were determined based on the number of loading berths associated with each model. The costs per equipment located at each berth has been recalculated based on the number of loading berths associated with the new model terminals. Therefore, the instrumentation and other major equipment capital costs differ for Model Terminals 5A, 5B, and 5C because of the different

number of loading berths associated with each model. Costs for piping, fittings, and associated installation were taken from the UTD estimate. Piping costs presented on a per-berth basis (e.g., headers) were adjusted to correspond with the number of loading berths associated with each model terminal. Piping size has been adjusted to retain the same stream velocity as in the original UTD scenario. Engineering, startup, and contingencies are assumed to total to 25 percent of installed equipment costs (per UTD).

The estimated capital costs of controlling emissions from each of the eight model terminals using an incineration based technology are presented in Tables 3-4 through 3-11. Complete documentation for these costs is provided in Appendix B.

3.3.1.2 Recovery. Capital and annual costs were also developed for a carbon adsorption-based emission control system. Much of the equipment needed to control air emissions from marine vessel loading operations via incineration is also necessary when carbon adsorption is used (e.g., piping, booster fans, detonation arresters, vapor headers, explosionproof alarms, probes, sensors, etc.). The piping, instrumentation, and other major equipment costs are calculated using the same bases. When using recovery-based control systems, inert gas, enrichment, or dilution air is no longer necessary. Therefore, an inert gas generator and cooling water system are not included in the costs for the recovery system. Piping sizes are also reduced to correspond to the lower noninerted emission stream flow rates.

The design and costs of the carbon adsorbers were determined using procedures outlined in the OAQPS Control Cost Manual.[5] Tables 3-12 through 3-16 present the capital and annual costs of carbon adsorption-based controls for each model terminal loading gasoline (i.e., Models 5A, 5B, 5C, 7A and 7B). Appendix C presents a summary of the carbon adsorber design characteristics for each Model Terminal. A detailed description of the development of the carbon adsorption system design characteristics for Model Terminal 5A is provided as Appendix D; Appendix D also provides complete documentation of all capital

and annual costs for Model Terminal 5A using a carbon adsorption-based control system. Table 3-17 provides a comparison of the estimated capital costs of incineration versus carbon adsorption for Model Terminal 5A. The percent difference in the capital costs indicates that incineration is more costly by 3.8 percent.

Note that because the cost estimates for carbon adsorption are focused on gasoline recovery, Model Terminals 6A, 6B, and 6C (which deal exclusively with crude oil) were not used to develop carbon adsorption costs. Crude oil emissions are not expected to be controlled by carbon adsorption because hydrogen sulfide (H_2S) present in crude oil vapor tends to poison the carbon bed; however, pretreatment (via a scrubber) could remove H_2S from the vapor prior to the adsorber. In addition, terminal owners are not expected to invest in carbon adsorption if they are required to control a variety of compounds because the design of carbon adsorbers is usually compound-specific.

3.3.2 Annual Costs

Annual costs from the UTD estimate were incorporated into this cost estimate where possible. Several annual costs not included in the original UTD estimate were added: these costs include labor (operating and maintenance) and overhead. Other annual costs, such as electrical and natural gas costs, were taken from the UTD estimate and modified as needed. Costs for operating labor and maintenance parts and labor are taken from EPA costing methodology.[5]

Maintenance parts and labor are added to UTD's preventive maintenance estimate in order to obtain total maintenance costs. The natural gas costs for incinerators are taken directly from the UTD estimate. The amount of natural gas needed for inert gas generators is based on the size of the inert gas generator.[7] Electrical consumption for the emission stream booster fans was taken from the UTD document for Model Terminals 5A through 5C and 6A through 6C and adjusted for electrical rate (dollars per kilowatt hour).[8] Electrical consumption for the emissions stream booster fans was calculated using EPA methodology for Model Terminals 7A and 7B.[5] (The original UTD electricity usage

appeared to be understated for Model Terminals 7A and 7B and reasonable for the other models. Therefore, the higher figure determined using EPA methodology is used for Model Terminals 7A and 7B.)

Overhead costs, which were not included in UTD's estimate, are calculated as 60 percent of operating labor and maintenance costs. Property taxes, insurance, and administration are calculated as 4 percent of the total capital costs (excluding vessel capital costs). Capital recovery is based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years. Vessel annual costs include maintenance and capital recovery costs (10 percent interest and a 20-year life).

The primary difference between the annual costs for an incineration-based system and a carbon adsorption-based system is that the gasoline recovered in the carbon adsorber can be sold for a recovery credit. Also, the carbon adsorber does not require any natural gas and the incinerator does not require steam, cooling water, or carbon. In addition, electricity costs are significantly higher for carbon adsorption than for incineration due to the fact that electricity is only needed to run the system fan in the incineration system, whereas the carbon adsorption system needs electricity to run the system fan, bed drying and cooling fan, cooling water pump, and solvent pump; however, the same rate ($/Kwh) is used to calculate electricity costs for the two systems. Other annual costs are essentially the same with labor and maintenance being slightly lower for carbon adsorption (no one is needed to operate and maintain the inert gas generator). Overhead, property taxes, and insurance costs are based on the same percentage for both carbon adsorption and incineration.

The total capital and annual costs for Model Terminal 5A for incineration and carbon adsorption fall within 3 to 5 percent of each other. The total terminal-only capital costs for Model 5A are $1,290,000 for incineration and $964,000 for carbon adsorption. However, these terminal-only costs are minor when compared to the associated total vessel retrofit costs, which are

estimated to be $7,360,000 for both incineration and carbon adsorption. Because the vessel retrofit costs represent 80 to 90 percent of the total capital cost (depending upon the model terminal), the choice of control device has little affect on the total cost of control. Total annual costs are likewise dominated by the vessel retrofit costs; vessel retrofit annual costs represent 70 to 80 percent of the total annual costs depending upon the model terminal. Table 3-18 shows vessel retrofit costs attributed to each of the eight model terminals. Although the carbon adsorption-based control system is slightly less expensive, a general conclusion that carbon adsorption is less expensive cannot be made because (1) all costs are estimates and a 3 to 5 percent difference is not significant, and (2) terminals that choose to incinerate may also choose to enrich rather than inert the vapors, and enriching is less expensive than inerting. Table 3-19 provides a comparison of the annual costs of incineration to those of carbon adsorption.

Equations for annual cost versus throughput were developed for each of the eight model terminals, based on incineration costs. The terminals listed in the data base are represented by a model terminal based on throughput, commodities loaded, and vessel types loaded. Appendix E lists each terminal, the model terminal to which it was assigned, terminal emissions (in pounds), and the associated annual costs of emission control. The cost equations were used to develop individual costs for each terminal. For a summary of the cost equations, see Appendix F. Annual costs are presented in Tables 3-4 through 3-11 for each model when using incineration and Tables 3-12 through 3-16 for Models 5A, 5B, 5C, 7A, and 7B, respectively, when using carbon adsorption. For complete documentation of all incineration-based costs and their sources, see Appendix B.

3.4 NATIONWIDE COSTS AND COST EFFECTIVENESS

The annual costs for a range of annual throughputs were necessary for each model terminal in order to derive costs for actual terminals. The loading rates were assumed to be fixed, so throughputs were varied by changing the number of loading hours

per year. Throughputs and costs were calculated at 50-hour intervals from 50 to 2,000 loading hours per year. A linear regression was performed on the data and equations generated for annual cost with respect to throughput. Appendix F shows the data tables of throughput versus costs and the linear regression output. The terminal-specific costs are calculated using the cost equation for the model terminal to which the actual terminal is assigned and the actual terminal throughput. Vessels are assigned to the terminals based on fleet factors provided by the Marine Board.[1] (Fleet factors are rough estimates of the average number of barrels transported per day.) Appendix E lists each terminal, the model terminal to which it was assigned, terminal emissions (in pounds), and the associated annual costs of emission control. Total nationwide annual costs were estimated by summing the costs for each terminal represented in the data base.

The estimated capital costs are the same for each terminal in a given model terminal category, except for the "associated vessel total capital investment" (e.g., the terminal-only capital costs are the same for each terminal assigned to Model 5A). The associated vessel total capital investment was calculated based on the terminal's throughput (see Section II.H of Appendix B).

Nationwide capital and annual costs are presented in Table 3-20. Table 3-21 presents the nationwide capital and annual costs based on incineration associated with the actual terminals that fit each model terminal. The total capital cost of retrofitting all of the terminals in the data base ranges from approximately $1.9 billion to $2.4 billion. The total capital cost of retrofitting both the terminals and the associated vessels ranges from $2.3 billion to $2.9 billion. The total annualized cost of retrofitting all of the terminals represented in the data base varies from $531 million to $619 million. The total annualized cost of retrofitting all of the terminals represented in the data base and the associated vessels ranges from $602 million to $690 million. The corresponding cost-effectiveness of retrofitting terminals and associated ships and

barges ranges from $8,000/Mg to $9,200/Mg and is based on an annual emissions reduction of 75,200 Mg/yr. Because the total annual costs of control are essentially the same for incineration and carbon adsorption, the cost effectiveness values are also about the same. Sample emission reduction calculations are included in Appendix B.

TABLE 3-1. DESCRIPTION OF MODEL TERMINALS

Model	No. of terminals	Ships	Size of ships	Barges[a]	Maximum loading rate, bbl/h	Actua loading rate, bbl/h	Hours per year	Comnodities[b]	Throughput
5A	9	0		4	16,000	8,000	2,000	Product	TP > 8 mm bbl/yr
5B	14	0		2	8,000	4,000	2,000	Product	4 mm < TP < 8 mm bbl/yr
5C	908	0		1	4,000	4,000	1,000	Product	TP < 4,000,000 bbl/yr
6A	18	1	70 kwdt	0	35,000	35,000	2,000	Crude oil	TP > 0
6B	8	0		2	8,000	4,000	2,000	Crude oil	4 mm TP < 8 mm bbl/yr
6C	187	0		1	4,000	4,000	1,000	Crude oil	TP < 4,000,000 bbl/yr
7A	649	1	35 kdwt	1	29,000	29,000	1,000	Product	TP < 29,000,000 bbl/yr
7B	6	2	35 kdwt	4	60,000	33,000	2,000	Product	TP > 29,000,000 bbl/yr

[a]All barges referred to here are inland river barges, Model Vessel 4.
[b]"Product" is defined as any noncrude oil commodity; however, terminals tat load both "product" and crude oil are considered product terminals.

TABLE 3-2. MODEL VESSELS[a]

Model	Vessel type	Vessel size	Commodity carried	Capacity, 1,000 bbl	Loading rate, bbl/hr	Fleet factor, bbl/vessel/d2[b]	Inert gas system present	Total capital investment, $	Total annualized costs, $/yr
1	Ship	70 kdwt	Crude oil	490	35,000	25,000	Y	168,000	24,500
2	Ship	35 kwdt	Product	262.5	25,000	20,000	N	426,000	64,400
3	Barge	19 kwdt	Crude oil	142.5	15,000	10,000	N	266,000	44,000
4	Barge	--	Product, crude oil	25	4,000	1,000	N	168,000	29,300

[a]All costs are in 1987 dollars.
[b]Fleet factors are an average of quantity moved per day.

TABLE 3-3. MODEL VESSEL CAPITAL AND ANNUAL COSTS[a]

Model	1[b]	2[c]	3[d]	4[e]
Capital costs				
Vapor header hardware	63,100	78,000	67,000	50,000
Instrumentation	71,400	161,000	81,000	17,000
Piping	0	102,000	65,000	67,200
Subtotal	135,000	341,000	213,000	134,000
Engineering, startup, and contingencies	33,600	85,000	53,200	33,600
Total capital cost	168,000	426,000	266,000	168,000
Annual costs				
Maintenance	48,000	14,400	12,800	9,600
Capital recovery	19,700	50,000	31,200	19,700
Total annual costs	24,500	64,400	44,000	29,300

[a]All costs are in 1987 dollars. Numbers have been rounded.
[b]70 kdwt oil carrier.
[c]35 kdwt product carrier.
[d]19 kdwt ocean barge.
[e]Inland river barge.

TABLE 3-4. CAPITAL AND ANNUAL COSTS: MODEL 5A[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	329,000	329,000
2. Inert gas (IG) generator[d]	167,000	167,000
3. Water system[e]	15,800	15,800
4. Other major equipment[f]	241,000	241,000
5. Piping[g]	171,000	228,000
6. Instrumentation[h]	49,800	49,800
Engineering, startup, contingencies[i]	243,000	257,000
Subtotal (terminal-only capital costs)	1,220,000	1,290,000
Associated vessel total capital investment[j]	7,360,000	7,360,000
TOTAL CAPITAL INVESTMENT (TCI)	8,580,000	8,650,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	3,520	3,520
2. Maintenance[l]	39,500	39,500
3. Natural gas[m]	56,700	56,700
4. Electricity[n]	5,300	5,300
B. Indirect Operating Costs		
1. Overhead[o]	25,800	25,800
2. Property taxes, insurance, and administration[p]	48,700	51,500
3. Capital recovery charge[q]	190,000	199,000
Subtotal (terminal-annual costs)	370,000	382,000
Vessel retrofit total annual costs	1,290,000	1,290,000
TOTAL ANNUAL COSTS	1,660,000	1,670,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	1,014	1,014
B. Cost effectiveness (incinerator only), $/Mg	370	380
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	1,600	1,600

TABLE 3-4. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x3,550])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 5A	660 ft to 1,400 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x (vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift)($12.96/hr)(323.8/342.5).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift)($14.26/hr)(323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-5. CAPITAL AND ANNUAL COSTS: MODEL 5B[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	303,000	303,000
2. Inert gas (IG) generator[d]	103,000	103,000
3. Water system[e]	15,800	15,800
4. Other major equipment[f]	159,000	159,000
5. Piping[g]	143,000	182,000
6. Instrumentation[h]	36,200	36,200
Engineering, startup, contingencies[i]	190,000	200,000
Subtotal (terminal-only capital costs)	949,000	998,000
Associated vessel total capital investment[j]	3,680,000	3,680,000
TOTAL CAPITAL INVESTMENT (TCI)	4,630,000	4,680,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	3,520	3,520
2. Maintenance[l]	39,500	39,500
3. Natural gas[m]	32,200	32,200
4. Electricity[n]	2,730	2,730
B. Indirect Operating Costs		
1. Overhead[o]	25,800	25,800
2. Property taxes, insurance, and administration[p]	38,000	39,900
3. Capital recovery charge[q]	148,000	154,000
Subtotal (terminal-annual costs)	290,000	298,000
Vessel retrofit total annual costs	643,000	643,000
TOTAL ANNUAL COSTS	933,000	941,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	507	507
B. Cost effectiveness (incinerator only), $/Mg	507	590
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	1,800	1,900

TABLE 3-5. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x1,775])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 5B	660 ft to 1,400 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel)x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift)($12.96/hr)(323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift)($14.26/hr)(323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert-gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-6. CAPITAL AND ANNUAL COSTS: MODEL 5C[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	290,000	290,000
2. Inert gas (IG) generator[d]	63,400	63,400
3. Water system[e]	15,800	15,800
4. Other major equipment[f]	118,000	118,000
5. Piping[g]	119,000	139,000
6. Instrumentation[h]	29,500	29,500
Engineering, startup, contingencies[i]	159,000	164,000
Subtotal (terminal-only capital costs)	795,000	819,000
Associated vessel total capital investment[j]	1,840,000	1,840,000
TOTAL CAPITAL INVESTMENT (TCI)	2,640,000	2,660,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	1,760	1,760
2. Maintenance[l]	36,200	36,200
3. Natural gas[m]	19,900	19,900
4. Electricity[n]	2,310	2,310
B. Indirect Operating Costs		
1. Overhead[o]	22,800	22,800
2. Property taxes, insurance, and administration[p]	31,800	32,800
3. Capital recovery charge[q]	124,000	127,000
Subtotal (terminal-annual costs)	239,000	243,000
Vessel retrofit total annual costs	321,000	321,000
TOTAL ANNUAL COSTS	560,000	564,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	254	254
B. Cost effectiveness (incinerator only), $/Mg	940	960
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	2,200	2,200

TABLE 3-6. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x887])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document)[1]:

Dock to incinerator:	Model 5C	660 ft to 1,400 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel)x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift)($12.96/hr)(323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($14.26/hr) (323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-7. CAPITAL AND ANNUAL COSTS: MODEL 6A[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	325,000	325,000
2. Inert gas (IG) generator[d]	0	0
3. Water system[e]	0	0
4. Other major equipment[f]	152,000	152,000
5. Piping[g]	141,000	1,550,000
6. Instrumentation[h]	33,700	33,700
Engineering, startup, contingencies[i]	163,000	516,000
Subtotal (terminal-only capital costs)	815,000	2,580,000
Associated vessel total capital investment[j]	1,290,000	1,290,000
TOTAL CAPITAL INVESTMENT (TCI)	2,100,000	3,870,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	1,760	1,760
2. Maintenance[l]	31,400	31,400
3. Natural gas[m]	7,650	7,650
4. Electricity[n]	1,770	1,770
B. Indirect Operating Costs		
1. Overhead[o]	19,900	19,900
2. Property taxes, insurance, and administration[p]	32,600	103,000
3. Capital recovery charge[q]	126,000	349,000
Subtotal (terminal-annual costs)	221,000	515,000
Vessel retrofit total annual costs	188,000	188,000
TOTAL ANNUAL COSTS	409,000	703,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	796	796
B. Cost effectiveness (incinerator only), $/Mg	280	650
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	510	880

TABLE 3-7. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x3,275])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 6A	660 ft to 6,000 ft
Natural gas to incinerator:	Model 6A	2,640 ft to 31,680 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift) ($12.96/hr) (323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr) (1 shift/8 hr)(0.5 hr/shift) ($14.26/hr) (323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs subtotal.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-8. CAPITAL AND ANNUAL COSTS: MODEL 6B[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	303,000	303,000
2. Inert gas (IG) generator[d]	103,000	103,000
3. Water system[e]	15,800	15,800
4. Other major equipment[f]	159,000	159,000
5. Piping[g]	143,000	182,000
6. Instrumentation[h]	36,200	36,200
Engineering, startup, contingencies[i]	190,000	200,000
Subtotal (terminal-only capital costs)	949,000	998,000
Associated vessel total capital investment[j]	3,680,000	3,680,000
TOTAL CAPITAL INVESTMENT (TCI)	4,630,000	4,680,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	3,520	3,520
2. Maintenance[l]	39,500	39,500
3. Natural gas[m]	32,200	32,200
4. Electricity[n]	2,730	2,730
B. Indirect Operating Costs		
1. Overhead[o]	25,800	25,800
2. Property taxes, insurance, and administration[p]	38,000	39,900
3. Capital recovery charge[q]	148,000	154,000
Subtotal (terminal-annual costs)	290,000	298,000
Vessel retrofit total annual costs	643,000	643,000
TOTAL ANNUAL COSTS	933,000	941,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	149	149
B. Cost effectiveness (incinerator only), $/Mg	1,900	2,000
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	6,300	6,300

TABLE 3-8. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x1,775])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 6B	660 ft to 1,400 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift) ($12.96/hr) (323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr) (1 shift/8 hr)(0.5 hr/shift) ($14.26/hr) (323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-9. CAPITAL AND ANNUAL COSTS: MODEL 6C[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	290,000	290,000
2. Inert gas (IG) generator[d]	63,400	63,400
3. Water system[e]	15,800	15,800
4. Other major equipment[f]	118,000	118,000
5. Piping[g]	119,000	139,000
6. Instrumentation[h]	29,500	29,500
Engineering, startup, contingencies[i]	159,000	164,000
Subtotal (terminal-only capital costs)	795,000	819,000
Associated vessel total capital investment[j]	1,840,000	1,840,000
TOTAL CAPITAL INVESTMENT (TCI)	2,640,000	2,660,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	1,760	1,760
2. Maintenance[l]	36,200	36,200
3. Natural gas[m]	19,900	19,900
4. Electricity[n]	2,310	2,310
B. Indirect Operating Costs		
1. Overhead[o]	22,800	22,800
2. Property taxes, insurance, and administration[p]	31,800	32,800
3. Capital recovery charge[q]	124,000	127,000
Subtotal (terminal-annual costs)	239,000	243,000
Vessel retrofit total annual costs	321,000	321,000
TOTAL ANNUAL COSTS	560,000	564,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	75	75
B. Cost effectiveness (incinerator only), $/Mg	3,200	3,200
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	7,500	7,500

TABLE 3-9. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x887])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 6C	660 ft to 1,400 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift) ($12.96/hr) (323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift) ($14.26/hr) (323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-10. CAPITAL AND ANNUAL COSTS: MODEL 7A[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	371,000	371,000
2. Inert gas (IG) generator[d]	312,000	312,000
3. Water system[e]	29,200	29,200
4. Other major equipment[f]	337,000	337,000
5. Piping[g]	340,000	1,020,000
6. Instrumentation[h]	69,600	69,600
Engineering, startup, contingencies[i]	365,000	535,000
Subtotal (terminal-only capital costs)	1,820,000	2,680,000
Associated vessel total capital investment[j]	3,300,000	3,300,000
TOTAL CAPITAL INVESTMENT (TCI)	5,120,000	5,980,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	1,760	1,760
2. Maintenance[l]	68,200	68,200
3. Natural gas[m]	96,600	96,600
4. Electricity[n]	10,400	10,400
B. Indirect Operating Costs		
1. Overhead[o]	42,000	42,000
2. Property taxes, insurance, and administration[p]	72,900	107,000
3. Capital recovery charge[q]	281,000	389,000
Subtotal (terminal-annual costs)	573,000	715,000
Vessel retrofit total annual costs	542,000	542,000
TOTAL ANNUAL COSTS	1,120,000	1,260,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	1,093	1,093
B. Cost effectiveness (incinerator only), $/Mg	530	660
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	1,000	1,200

TABLE 3-10. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x6,430])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 7A	660 ft to 6,000 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift) ($12.96/hr) (323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr) (1 shift/8 hr)(0.5 hr/shift) ($14.26/hr) (323.8/342.5)(2 [for parts])(2) + 64,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs subtotal.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-11. CAPITAL AND ANNUAL COSTS: MODEL 7B[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Installed equipment costs, $, 1987		
1. Incinerator[c]	490,000	490,000
2. Inert gas (IG) generator[d]	684,000	684,000
3. Water system[e]	29,200	29,200
4. Other major equipment[f]	534,000	534,000
5. Piping[g]	414,000	1,370,000
6. Instrumentation[h]	96,700	96,700
Engineering, startup, contingencies[i]	562,000	801,000
Subtotal (terminal-only capital costs)	2,810,000	4,000,000
Associated vessel total capital investment[j]	10,300,000	10,300,000
TOTAL CAPITAL INVESTMENT (TCI)	13,100,000	14,300,000
II. Annual Costs, $, 1987		
A. Direct		
1. Labor[k]	3,520	3,520
2. Maintenance[l]	71,500	71,500
3. Natural gas[m]	210,000	210,000
4. Electricity[n]	24,700	24,700
B. Indirect Operating Costs		
1. Overhead[o]	45,000	45,000
2. Property taxes, insurance, and administration[p]	112,000	160,000
3. Capital recovery charge[q]	438,000	590,000
Subtotal (terminal-annual costs)	906,000	1,100,000
Vessel retrofit total annual costs	1,730,000	1,730,000
TOTAL ANNUAL COSTS	2,630,000	2,830,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	2,692	2,692
B. Cost effectiveness (incinerator only), $/Mg	340	410
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	980	1,100

TABLE 3-11. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote g below).
[c]Incinerator cost = (220,400+[11.57x14,638])x323.8/342.5; plus 33 percent for installation.
[d]Capital costs from Richardson's and adjusted for size.[6]
[e]Capital cost of brackish water system for inert gas scrubber.
[f]This category includes fans, valves, and detonation arrestors.[2]
[g]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to incinerator:	Model 7B	660 ft to 6,000 ft

[h]This category includes alarms, probes, and sensors.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Operating labor (for incinerator and IG generator) = (2,000 hr/yr) (1 shift/8 hr)(0.5 hr/shift) ($12.96/hr) (323.8/342.5)(2).[2,5,9]
[l]Maintenance for incinerator and IG generator = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($14.26/hr) (323.8/342.5)(2 [for parts])(2) + 64,800.[2,5,9]
[m]Assumed pilot light only for incinerator and natural gas for IG generator; cost of natural gas = $3.43/1,000 ft^3.[2]
[n]Electricity to run incinerator and inert gas blower fans.
[o]Calculated as 60 percent of labor and maintenance.[5]
[p]Four percent of terminal capital costs.[5]
[q]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.

TABLE 3-12. CAPITAL AND ANNUAL COSTS: MODEL 5A[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Carbon Adsorber[c]	398,000	398,000
1. Other major equipment[d]	234,000	234,000
2. Piping[e]	50,800	89,700
3. Instrumentation[f]	49,800	49,800
4. Inert gas system[g]	0	0
5. Water system[h]	0	0
6. Subtotal	733,000	772,000
7. Engineering, startup, contingencies[i]	183,000	193,000
Subtotal	916,000	964,000
Associated vessel total capital investment[j]	7,364,000	7,360,000
TOTAL CAPITAL INVESTMENT (TCI)	8,280,000	8,330,000
II. Annual Costs		
1. Maintenance[k]	36,200	36,200
2. Steam[l]	43,700	43,700
3. Electricity[m]	89,700	89,700
4. Cooling water[n]	5,000	5,000
5. Carbon replacement[o]	48,900	48,900
6. Labor[p]	1,760	1,760
7. Overhead[q]	22,800	22,800
8. Property taxes, insurance, administration[r]	36,600	38,600
9. Capital recovery charge[s]	133,000	139,000
Recovery credit[t]	(158,000)	(158,000)
Subtotal	260,000	268,000
Vessel retrofit TAC (O&M, CRC, PITI)	1,290,000	1,290,000
		1,560,000
TOTAL	1,550,000	
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	985	985
B. Cost effectiveness (adsorber only), $/Mg	260	270
C. Cost effectiveness (adsorber and retrofitting vessels), $/Mg	1,600	1,600

TABLE 3-12. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote e below).
[c]Carbon adsorber cost calculated based on procedures outlined in the OAQPS Control Cost Manual.[4] Includes cost of adsorber plus ductwork and other necessary equipment not included with the unit.
[d]This category includes fans, valves, and detonation arrestors.[2]
[e]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to adsorber:	Model 5A	660 ft to 1,400 ft

[f]This category includes alarms, probes, and sensors.
[g]Not necessary.
[h]Not necessary.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Maintenance for carbon adsorber = (2,000 hr/yr) (1 shift/8 hr) (0.5 hr/shift)($14.26/hr)(323.8/342.5)(2 [for parts]) + 32,800.[2,5,9]
[l]Steam cost for steam used during carbon bed regeneration. Calculated based on procedures in the OAQPS Control Cost Manual and a steam cost of $6/1,000 lb.
[m]Electricity to run incinerator and inert gas blower fans.
[n]Cooling water costs are a function of steam usage = 3.43 gal/lb steam X ($43.72/($6/1,000 lb steam)) x $.20/1000 gal = $5,000
[o]Carbon replacement costs are based on procedures in the OAQPS Control Cost Manual, a 2-year life, and a 10-percent interest rate.
[p]Operating labor (for carbon adsorber) = (2,000 hr/yr) (1 shift/8 hr)(0.5 hr/shift) ($12.96/hr) (323.8/342.5).[2,5,9]
[q]Calculated as 60 percent of labor and maintenance.[5]
[r]Four percent of terminal capital costs.[5]
[s]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.
[t]Recovery credit = 2285 lb/hr x 2000 hr/yr x $.08/lb x 0.95 x (323.8/355.4) x 0.50 = $158,200/yr.[5,9]

TABLE 3-13. CAPITAL AND ANNUAL COSTS: MODEL 5B[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Carbon Adsorber[c]	264,000	264,000
1. Other major equipment[d]	159,000	159,000
2. Piping[e]	25,800	45,800
3. Instrumentation[f]	35,200	36,200
4. Inert gas system[g]	0	0
5. Water system[h]	0	0
6. Subtotal	485,000	505,000
7. Engineering, startup, contingencies[i]	121,000	126,000
Subtotal	606,000	631,000
Associated vessel total capital investment[j]	3,680,000	3,680,000
TOTAL CAPITAL INVESTMENT (TCI)	4,290,000	4,310,000
II. Annual Costs		
1. Maintenance[k]	36,200	36,200
2. Steam[l]	21,900	21,900
3. Electricity[m]	22,600	22,600
4. Cooling water[n]	2,500	2,500
5. Carbon replacement[o]	24,400	24,400
6. Labor[p]	1,760	1,760
7. Overhead[q]	22,800	22,800
8. Property taxes, insurance, administration[r]	24,200	25,200
9. Capital recovery charge[s]	90,600	93,700
Recovery credit[t]	(79,100)	(79,100)
Subtotal	168,000	172,000
Vessel retrofit TAC (O&M, CRC, PITI)	643,000	643,000
TOTAL	811,000	815,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	492	492
B. Cost effectiveness (incinerator only), $/Mg	340	350
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	1,600	1,700

TABLE 3-13. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote e below).
[c]Carbon adsorber cost calculated based on procedures outlined in the OAQPS Control Cost Manual.[4] Includes cost of adsorber plus ductwork and other necessary equipment not included with the unit.
[d]This category includes fans, valves, and detonation arrestors.[2]
[e]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to adsorber:	Model 5B	660 ft to 1,400 ft

[f]This category includes alarms, probes, and sensors.
[g]Not necessary.
[h]Not necessary.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Maintenance for carbon adsorber = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($14.26/hr)(323.8/342.5)(2 [for parts]) + 32,800.[2,5,9]
[l]Steam cost for steam used during carbon bed regeneration. Calculated based on procedures in the OAQPS Control Cost Manual and a steam cost of $6/1,000 lb.
[m]Electricity to run incinerator and inert gas blower fans.
[n]Cooling water costs are a function of steam usage = 3.43 gal/lb steam X ($21.86/($6/1,000 lb steam)) x $.20/1000 gal = $5,000
[o]Carbon replacement costs are based on procedures in the OAQPS Control Cost Manual, a 2-year life, and a 10-percent interest rate.
[p]Operating labor (for carbon adsorber)= (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($12.96/hr)(323.8/342.5).[2,5,9]
[q]Calculated as 60 percent of labor and maintenance.[5]
[r]Four percent of terminal capital costs.[5]
[s]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.
[t]Recovery credit = 1143 lb/hr x 2000 hr/yr x $.08/lb x 0.95 x (323.8/355.4) x 0.50 = $79,100/yr.[9]

TABLE 3-14. CAPITAL AND ANNUAL COSTS: MODEL 5C[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Carbon Adsorber[c]	183,000	183,000
1. Other major equipment[d]	118,000	118,000
2. Piping[e]	16,900	31,400
3. Instrumentation[f]	29,500	29,500
4. Inert gas system[g]	0	0
5. Water system[h]	0	0
6. Subtotal	347,000	362,000
7. Engineering, startup, contingencies[i]	86,800	90,500
Subtotal	434,000	453,000
Associated vessel total capital investment[j]	1,840,000	1,840,000
TOTAL CAPITAL INVESTMENT (TCI)	2,270,000	2,290,000
II. Annual Costs		
1. Maintenance[k]	34,500	34,500
2. Steam[l]	5,460	5,460
3. Electricity[m]	2,880	2,880
4. Cooling water[n]	625	625
5. Carbon replacement[o]	12,200	12,200
6. Labor[p]	881	881
7. Overhead[q]	21,200	21,200
8. Property taxes, insurance, administration[r]	17,400	18,100
9. Capital recovery charge[s]	66,400	68,700
Recovery credit[t]	(19,800)	(19,800)
Subtotal	142,000	145,000
Vessel retrofit TAC (O&M, CRC, PITI)	321,000	321,000
TOTAL	463,000	466,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	246	246
B. Cost effectiveness (incinerator only), $/Mg	580	590
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	1,900	1,900

TABLE 3-14. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote e below).
[c]Carbon adsorber cost calculated based on procedures outlined in the OAQPS Control Cost Manual.[4] Includes cost of adsorber plus ductwork and other necessary equipment not included with the unit.
[d]This category includes fans, valves, and detonation arrestors.[2]
[e]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to adsorber:	Model 5C	660 ft to 1,400 ft

[f]This category includes alarms, probes, and sensors.
[g]Not necessary.
[h]Not necessary.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel)x(vessels) (see Table 3-12).
[k]Maintenance for carbon adsorber = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($14.26/hr)(323.8/342.5)(2 [for parts])(2) + 32,800.[2,5,9]
[l]Steam cost for steam used during carbon bed regeneration. Calculated based on procedures in the OAQPS Control Cost Manual and a steam cost of $6/1,000 lb.
[m]Electricity to run incinerator and inert gas blower fans.
[n]Cooling water costs are a function of steam usage = 3.43 gal/lb steam X ($5.90/($6/1,000 lb steam)) x $.20/1000 gal = $675
[o]Carbon replacement costs are based on procedures in the OAQPS Control Cost Manual, a 2-year life, and a 10-percent interest rate.
[p]Operating labor (for carbon adsorber) = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($12.96/hr)(323.8/342.5).[2,5,9]
[q]Calculated as 60 percent of labor and maintenance.[5]
[r]Four percent of terminal capital costs.[5]
[s]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.
[t]Recovery credit = 1143 lb/hr x 1000 hr/yr x $.08/lb x 0.95 x (323.8/355.4) x 0.50 = $19,800/yr.[9]

TABLE 3-15. CAPITAL AND ANNUAL COSTS: MODEL 7A[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs[c]		
Carbon Adsorber	452,000	452,000
1. Other major equipment[d]	337,000	337,000
2. Piping[e]	144,000	499,000
3. Instrumentation[f]	69,600	69,600
4. Inert gas system[g]	0	0
5. Water system[h]	0	0
6. Subtotal	1,000,000	1,360,000
7. Engineering, startup, contingencies[i]	250,000	340,000
Subtotal	1,250,000	1,700,000
Associated vessel total capital investment[j]	3,300,000	3,300,000
TOTAL CAPITAL INVESTMENT (TCI)	4,550,000	5,000,000
II. Annual Costs		
1. Maintenance[k]	34,500	34,500
2. Steam[l]	23,500	23,500
3. Electricity[m]	37,100	37,100
4. Cooling water[n]	2,690	2,690
5. Carbon replacement[o]	46,900	46,900
6. Labor[p]	881	881
7. Overhead[q]	21,200	21,200
8. Property taxes, insurance, administration[r]	50,000	68,000
9. Capital recovery charge[s]	184,000	241,000
Recovery credit[t]	(85,200)	(85,200)
Subtotal	316,000	390,000
Vessel retrofit TAC (O&M, CRC, PITI)	1,290,000	1,290,000
TOTAL	1,601,000	1,680,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	1,061	1,061
B. Cost effectiveness (incinerator only), $/Mg	300	370
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	1,500	1,600

TABLE 3-15. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote e below).
[c]Carbon adsorber cost calculated based on procedures outlined in the OAQPS Control Cost Manual.[4] Includes cost of adsorber plus ductwork and other necessary equipment not included with the unit.
[d]This category includes fans, valves, and detonation arrestors.[2]
[e]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to adsorber:	Model 7A	660 ft to 6,000 ft

[f]This category includes alarms, probes, and sensors.
[g]Not necessary.
[h]Not necessary.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Maintenance for carbon adsorber = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($14.26/hr)(323.8/342.5) (2 [for parts]) + 64,800.[2,5,9]
[l]Steam cost for steam used during carbon bed regeneration. Calculated based on procedures in the OAQPS Control Cost Manual and a steam cost of $6/1,000 lb.
[m]Electricity to run incinerator and inert gas blower fans.
[n]Cooling water costs are a function of steam usage = 3.43 gal/lb steam X ($23.52/($6/1,000 lb steam)) x $.20/1000 gal = $5,000
[o]Carbon replacement costs are based on procedures in the OAQPS Control Cost Manual, a 2-year life, and a 10-percent interest rate.
[p]Operating labor (for carbon adsorber) = (2,000 hr/yr) (1 shift/8 hr)(0.5 hr/shift) ($12.96/hr) (323.8/342.5).[2,5,9]
[q]Calculated as 60 percent of labor and maintenance.[5]
[r]Four percent of terminal capital costs.[5]
[s]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.
[t]Recovery credit = 1230 lb/hr x 2000 hr/yr x $.08/lb x 0.95 x (323.8/355.4) x 0.50 = $85,200/yr.[9]

TABLE 3-16. CAPITAL AND ANNUAL COSTS: MODEL 7B[a]
(1987 Dollars)

	Low[b]	High[b]
I. Capital Costs		
Carbon Adsorber[c]	783,000	783,000
1. Other major equipment[d]	534,000	534,000
2. Piping[e]	174,000	582,000
3. Instrumentation[f]	96,700	96,700
4. Inert gas system[g]	0	0
5. Water system[h]	0	0
6. Subtotal	1,590,000	2,000,000
7. Engineering, startup, contingencies[i]	397,000	500,000
Subtotal	1,990,000	2,500,000
Associated vessel total capital investment[j]	10,300,000	10,300,000
TOTAL CAPITAL INVESTMENT (TCI)	12,300,000	12,800,000
II. Annual Costs		
1. Maintenance[k]	36,200	36,200
2. Steam[l]	43,700	116,000
3. Electricity[m]	479,000	479,000
4. Cooling water[n]	13,300	13,300
5. Carbon replacement[o]	116,000	116,000
6. Labor[p]	1,760	1,760
7. Overhead[q]	22,800	22,800
8. Property taxes, insurance, administration[r]	76,600	100,000
9. Capital recovery charge[s]	283,000	348,000
Recovery credit[t]	(420,000)	(420,000)
Subtotal	728,000	812,000
Vessel retrofit TAC (O&M, CRC, PITI)	643,000	643,000
TOTAL	1,370,000	1,460,000
III. Cost Effectiveness		
A. Emission reduction, Mg/yr	2,613	2,613
B. Cost effectiveness (incinerator only), $/Mg	280	310
C. Cost effectiveness (incinerator and retrofitting vessels), $/Mg	520	560

TABLE 3-16. (continued)

[a]Costs rounded to three significant figures; cost effectiveness rounded to two significant figures.
[b]Total capital and annual costs in the "low" column are lower than those in the "high" column due to shorter assumed piping runs (see Footnote e below).
[c]Carbon adsorber cost calculated based on procedures outlined in the OAQPS Control Cost Manual.[4] Includes cost of adsorber plus ductwork and other necessary equipment not included with the unit.
[d]This category includes fans, valves, and detonation arrestors.[2]
[e]Piping costs are taken from UTD cost estimate. Costs assumed linear on a per-foot basis. Lengths varied as follows (shorter distance determined from cost sensitivity analysis; greater distance from UTD cost document[1]):

Dock to adsorber:	Model 7B	660 ft to 6,000 ft

[f]This category includes alarms, probes, and sensors.
[g]Not necessary.
[h]Not necessary.
[i]Engineering = 10 percent, startup = 10 percent, and contingencies = 5 percent of installed equipment cost.[2]
[j]Cost for vessel retrofit taken from the UTD cost estimate.[2] The number of vessels required was calculated using fleet factors in the Marine Board document.[11] Total Capital Investment (TCI) = (TCI per vessel) x(vessels) (see Table 3-12).
[k]Maintenance for carbon adsorber = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($14.26/hr)(323.8/342.5) (2 [for parts]) + 64,800.[2,5,9]
[l]Steam cost for steam used during carbon bed regeneration. Calculated based on procedures in the OAQPS Control Cost Manual and a steam cost of $6/1,000 lb.
[m]Electricity to run incinerator and inert gas blower fans.
[n]Cooling water costs are a function of steam usage = 3.43 gal/lb steam X ($116.30/($6/1,000 lb steam)) x $.20/1000 gal = $13,300
[o]Carbon replacement costs are based on procedures in the OAQPS Control Cost Manual, a 2-year life, and a 10-percent interest rate.
[p]Operating labor (for carbon adsorber) = (2,000 hr/yr)(1 shift/8 hr)(0.5 hr/shift)($12.96/hr) (323.8/342.5).[2,5,9]
[q]Calculated as 60 percent of labor and maintenance.[5]
[r]Four percent of terminal capital costs.[5]
[s]Calculated as (0.16275x[capital costs subtotal - piping])+(0.1175x[piping]) based on an interest rate of 10 percent, an equipment life of 10 years, and a piping life of 20 years.
[t]Recovery credit = 6066 lb/hr x 2000 hr/yr x $.08/lb x 0.95 x (323.8/355.4) x 0.50 = $420,000/yr.[9]

TABLE 3-17. CAPITAL COSTS COMPARISON (MODEL TERMINAL 5A): INCINERATION VS. CARBON ADSORPTION

Capital cost components	Incineration, $000[a]	Carbon adsorption, $000[b]
• Incinerator/adsorber	329	398
• Inert gas generator	167	0
• Water system	16	0
• Other major equipment	241	234
• Piping	228	90
• Instrumentation	50	50
• Engineering, startup, contingencies	257	193
Subtotal (terminal only capital costs)	1,290	964
• Vessel retrofit TCI	7,360	7,360
Total Capital Investment	8,650	8,330

[a]Documentation of capital costs for incineration-based system is provided in Attachment 4.
[b]Documentation of capital costs for carbon adsorption-based system is provided in Attachment 3.

TABLE 3-18. TOTAL ANNUALIZED VESSEL RETROFIT COSTS

Model	Throughput, mm bbl/yr	Model vessels, No.	Fleet factors[a]		No. of vessels[b]		Total annual cost per vessel thousands of dollars[c]		Total annualized cost, thousands of dollars
			Ship	Barge	Ship	Barge	Ship	Barge	
5A	16	4	--	1,000	--	43.84	--	29.3	1,286
5B	8	4	--	1,000	--	21.92	--	29.3	643
5C	4	4	--	1,000	--	10.96	--	29.3	321
6A	70	1	25,000	--	7.67	--	24.5	--	188
6B	8	4	--	1,000	--	21.92	--	29.3	643
6C	4	4	--	1,000	--	10.96	--	29.3	321
7A	29	2, 4	20,000	1,000	3.42	10.96	64.4	29.3	542
7B	66	2, 4	20,000	1,000	6.85	43.84	64.4	29.3	1,727

[a]Fleet factors are rough estimates of the average vessel throughput of cargo per day.
[b]Number of vessels = throughput/fleet factor/365.
[c]Maintenance plus capital recovery charge for retrofit cost.

TABLE 3-19. ANNUAL COSTS COMPARISON (MODEL TERMINAL 5A): INCINERATION VS. CARBON ADSORPTION

Annual cost components	Incineration, $000[a]	Carbon adsorption, $000[b]
· Labor	3.5	1.8
· Maintenance	39.5	36.2
· Natural gas	56.7	0
· Electricity	5.3	89.7
· Steam	0	43.7
· Cooling water	0	5.0
· Carbon replacement	0	48.9
· Overhead	25.8	22.8
· Property taxes, insurance	51.5	38.6
· Capital recovery charge	199	139
· Recovery credit	0	(158)
Subtotal (terminal only annual costs)	382	267
· Vessel retrofit TAC	1,290	1,290
Total Annual Costs	1,670	1,550

[a]Documentation of capital costs for incineration-based system is provided in Attachment 4.
[b]Documentation of capital costs for carbon adsorption-based system is provided in Attachment 3.

TABLE 3-20. NATIONWIDE CAPITAL AND ANNUAL COSTS AND COST EFFECTIVENESS

	Capital cost, mm $/yr	Annual cost, m $/yr	Cost effectiveness, $/Mg[a]
Terminals only	2,120-2,740	565-669	10,700-12,700
Vessels only	493	84.2	--
Total (terminals and vessels)	2,610-3,230	649-753	12,300-14,300

[a]Based on an annual emission reduction of 52,600 Mg/yr; cost effectiveness = annual cost/emission reduction.

TABLE 3-21. NATIONWIDE ANNUAL COSTS TO CONTROL EMISSIONS[a]

Model	No. of terminals assigned to model	No. of vessels to retrofit		Capital cost of retrofitting terminals only, mm $	Capital cost to retrofit associated vessels, mm $	Capital cost to retrofit both terminals and associated vessels, mm $	Annual cost of retrofitting terminals only, mm $	Annual cost to retrofit associated vessels, mm $	Annual cost to retrofit both terminals and associated vessels, mm $
		Ships	Barges						
5A	9	0	617	11.0-11.6	104	114.6-115.3	3.68-3.79	18.1	21.8-21.9
5B	14	0	214	13.3-14.0	36.0	49.3049.9	3.88-3.99	6.28	10.2-10.3
5C	908	0	690	721-744	116	837-860	199-203	20.2	219.223
6A	18	51	0	14.7-46.4	8.62	23.3-55.0	3.89-9.17	1.26	5.15-10.4
6B	8	0	124	7.60-7.98	20.8	28.4-28.8	2.21-2.28	3.64	5.86-5.92
6C	187	0	170	149-153	28.6	177-182	41.0-41.8	4.99	46.0-46.8
7A	649	146	467	1,183-1,736	141	1,324-1,877	307-399	23.1	330-422
7B	6	26	167	16.9-24.0	39.1	56.0-63.1	4.90-6.09	6.57	11.5-12.7
TOTAL	1,799	223	2,449	2,120-2,740	493	2,610-3,230	565-669	84.2	649-753

[a]All costs are in 1987 dollars. Numbers have been rounded.

3.5 REFERENCES FOR CHAPTER 3

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4.0 REGULATORY ALTERNATIVES

4.1 INTRODUCTION

The purpose of this chapter is to present the regulatory options that have been developed by EPA. The regulatory alternatives in this chapter represent the various courses of action that EPA could take in regulating air emissions from marine vessel loading operations. The environmental, cost, and economic impacts associated with the application of these alternatives to marine vessel loading operations are based on data presented in previous chapters. The EPA has developed cost and emissions estimates for each facility based on the models discussed in previous chapters. Therefore, the impacts of the regulatory alternatives are based on the models' approximating actual terminals.

Data in the EPA marine vessels data base includes information on 1,648 marine terminals that load liquids in one of thirteen commodity categories determined to emit volatile organic compounds (VOC's) and/or hazardous air pollutants (HAP's). The current data base is a portion of the 1988 Waterborne Commerce of the United States (WCUS) data base that is maintained by the Army Corps of Engineers' Statistics Center. The data base has information on commodity, annual barge throughput, annual tanker throughput, state, and amount of crude oil unloaded annually. Annual costs and emissions were estimated based on commodity and barge throughput.

4.2 REGULATORY ALTERNATIVES

Table 4-1 presents the regulatory alternatives developed by EPA to evaluate the environmental and cost impacts of potential emissions controls on marine vessel loading operations. The

regulatory alternatives represent incremental increases in the commmodity throughput cutoffs that are applicable to marine vessel loading operations when moving from Regulatory Alternative A to Regulatory Alternative E. The control level for the regulatory alternatives is 98 percent removal efficiency. The cutoff levels refer to a terminal's total annual throughput of the stated commodity categories. Any terminal annually loading greater than the cutoff for a given commodity category will be subject to the regulation. Cutoffs have been grouped in the regulatory alternatives such that the economic impacts on the terminals loading the affected commodities are similar.

The regulatory alternatives are presented in decreasing order of stringency. Regulatory alternative A represents the maximum level of nationwide control. At this control level, an estimated 98 percent of air emissions from marine vessel loading operations would be captured and controlled; there are no cutoffs and all commodity categories are controlled. All facilities in the current data base would be subject to the regulation. Regulatory Alternative B limits the commodity categories to be controlled and has annual throughput cutoffs. The commodity categories to be controlled are the four with the highest emission factors. Regulatory Alternatives C, D, and E would control only gasoline and crude oil loadings. The only difference between Regulatory Alternatives C, D, and E is that the cutoffs become less stringent when moving from Regulatory Alternative C to Regulatory Alternative E. Under Regulatory Alternative E, an estimated 70 percent of air emissions would be controlled. Table 4-1 presents all the regulatory alternatives and expected VOC emissions reductions. Tables 4-2 to 4-4 present the same regulatory alternatives for VOC and HAP emissions along with different scenarios for the control of the Alyeska facility. The emissions reduction estimates presented in Table 4-1 are based on the assumption that vapors are thermally destroyed. If a recovery technology were used, the emissions reductions would decrease slightly.

The Alyeska facility represents 53 percent of the nationwide uncontrolled emissions and 27 million dollars in annual costs if vapors are to be incinerated. If Alyeska is included as a controlled facility, Regulatory Alternatives A and B would constitute major rules (annual costs of 100 million dollars or greater). If Alyeska remains uncontrolled, only Regulatory Alternative A would be a major rule.

The average terminal affected by Regulatory Alternative E has annual emissions in excess of 100 megagrams [Mg]. For Regulatory Alternatives D and C, the average terminal affected by moving to a more stringent regulatory alternative has annual emissions in excess of 100 Mg. The average terminal affected by moving to Regulatory Alternative B or A does not have annual emissions in excess of 100 Mg.

TABLE 4-1. REGULATORY ALTERNATIVES VOC's[a]

Alyeska: Incineration
Other terminals: Incineration
Alaska terminals: Controlled

Alternatives		VOC emissions reduction, Mg/yr[c]	Percent VOC emissions reduction[c]	No. of affected terminals	Costs, $ millions[b]		Cost effective-ness, $/Mg	Incremental cost effectiveness, $/Mg
					Capital[d]	Annual[d]		
A. All terminals		73,500	98	1,780	3,200	750	10,000	82,000
B. Gasoline	>0.5 MM bbl/yr	65,600	87	104	560	99	1,500	8,400
Toluene	>0.5 MM bbl/yr							
Alcohols	>1.5 MM bbl/yr							
Crude oil	>5 MM bbl/yr							
C. Gasoline	>1 MM bbl/yr	63,100	84	60	470	78	1,200	4,500
Crude oil	>10 MM bbl/yr							
D. Gasoline	>5 MM bbl/yr	57,100	76	25	340	51	890	2,100
Crude oil	>100 MM bbl/yr							
E. Gasoline	>10 MM bbl/yr	52,400	70	13	290	41	780	N/A
Crude oil	>100 MM bbl/yr							

[a]Terminals affected by proposed or promulgated state regulations are not included in the above cost and emission estimates, with the exception of terminals located in Alaska. Assumes Alyeska uses incineration.

[b]Capital and annual costs were developed for both carbon adsorption and incineration. Because the difference in costs between incineration and carbon adsorption is only 3 percent, only the incineration costs are presented here.

[c]Tables show 98 percent control efficiency, standard for incineration and achievable with carbon adsorption.

[d]Alyeska represents 185 million dollars of all capital cost figures and 27 million dollars of all annual cost figures.

TABLE 4-2. REGULATORY ALTERNATIVES VOC'sa

Alyeska: Uncontrolled
Other terminals: Incineration
Alaska terminals: Uncontrolled

Alternatives	VOC emissions reduction, Mg/yr	Percent VOC emissions reduction	No. of affected terminals	Costs, $ millions[b]		Cost effective-ness, $/Mg	Incremental cost effectiveness, $/Mg
				Capital	Annual		
A. All terminals	32,600	98	1,777	3,000	720	22,000	82,000
B. Gasoline >0.5 MM bbl/yr Toluene >0.5 MM bbl/yr Alcohols >1.5 MM bbl/yr Crude oil >5 MM bbl/yr	24,700	74	101	340	70	2,800	8,400
C. Gasoline >1 MM bbl/yr Crude oil >10 MM bbl/yr	22,300	67	58	240	49	2,200	4,500
D. Gasoline >5 MM bbl/yr Crude oil >100 MM bbl/yr	16,300	43	23	110	22	1,500	2,100
E. Gasoline >10 MM bbl/yr Crude oil >100 MM bbl/yr	11,600	29	11	58	12	1,200	N/A

[a]Terminals affected by proposed or promulgated state regulations are not included in the above cost and emission estimates.
[b]Capital and annual costs were developed for both carbon adsorption and incineration. Because the difference in costs between incineration and carbon adsorption is only 3 percent, only the incineration costs are presented here.
[c]Tables show 98 percent control efficiency, standard for incineration and achievable with carbon adsorption.

TABLE 4-3. REGULATORY ALTERNATIVES TOXICS[a]

Alyeska: Incineration
Other terminals: Incineration
Alaska terminals: Controlled

Alternatives	HAP emissions reduction, Mg/yr	Percent HAP emissions reduction[c]	No. of affected terminals	Costs, $ millions[b]		Cost effectiveness, $/Mg
				Capital[d]	Annual[d]	
A. All terminals	7,770	98	1,780	3,200	750	97,000
B. Gasoline >0.5 MM bbl/yr Toluene >0.5 MM bbl/yr Alcohols >1.5 MM bbl/yr Crude oil >5 MM bbl/yr	7,040	79	104	560	99	14,000
C. Gasoline >1 MM bbl/yr Crude oil >10 MM bbl/yr	6,660	64	60	470	78	12,000
D. Gasoline >5 MM bbl/yr Crude oil >100 MM bbl/yr	6,200	57	25	340	51	8,200
E. Gasoline >10 MM bbl/yr Crude oil >100 MM bbl/yr	6,000	51	13	240	41	6,900

[a]Terminals affected by proposed or promulgated state regulations are not included in the above cost and emission estimates, with the exception of terminals located in Alaska. Assumes Alyeska uses incineration.
[b]Capital and annual costs were developed for both carbon adsorption and incineration. Because the difference in costs between incineration and carbon adsorption is only 3 percent, only the incineration costs are presented here.
[c]Tables show 98 percent control efficiency, standard for incineration and achievable with carbon adsorption.
[d]Alyeska represents 185 million dollars of all capital cost figures and 27 million dollars of all annual cost figures.

TABLE 4-4. REGULATORY ALTERNATIVES TOXICS[a]

Alyeska: Uncontrolled
Other terminals: Incineration
Alaska terminals: Uncontrolled

Alternatives		HAP emissions reduction, Mg/yr	Percent HAP emissions reduction[c]	No. of affected terminals	Costs, $ millions[b]		Cost effectiveness, $/Mg
					Capital	Annual	
A. All terminals		2,850	98	1,777	3,000	720	250,000
B. Gasoline Toluene Alcohols Crude oil	>0.5 MM bbl/yr >0.5 MM bbl/yr >1.5 MM bbl/yr >5 MM bbl/yr	2,120	64	101	340	70	33,000
C. Gasoline Crude oil	>1 MM bbl/yr >10 MM bbl/yr	1,740	38	58	240	49	28,000
D. Gasoline Crude oil	>5 MM bbl/yr >100 MM bbl/yr	1,280	26	23	110	22	17,000
E. Gasoline Crude oil	>10 MM bbl/yr >100 MM bbl/yr	1,060	16	11	58	12	11,000

[a]Terminals affected by proposed or promulgated state regulations are not included in the above cost and emission estimates.
[b]Capital and annual costs were developed for both carbon adsorption and incineration. Because the difference in costs between incineration and carbon adsorption is only 3 percent, only the incineration costs are presented here.
[c]Tables show 98 percent control efficiency, standard for incineration and achievable with carbon adsorption.

TABLE 4-5. SECONDARY AIR IMPACTS BY REGULATORY ALTERNATIVES[a]

Alyeska; Incineration
Other terminals: Incineration
Alaska terminals: Controlled

Alternatives			Annual SO_x emissions Mg/yr	Annual NO_x emissions Mg/yr	Annual CO emissions Mg/yr	Total Annual SO_x, NO_x, and CO emissions Mg/yr	Annual CO_2 emissions Mg/yr
A.	All terminals		69	265	250	584	229,000
B.	Gasoline Toluene Alcohols Crude oil	>0.5 MM bbl/yr >0.5 MM bbl/yr >1.5 MM bbl/yr >5 MM bbl/yr	65	132	125	322	204,000
C.	Gasoline Crude oil	>1 MM bbl/yr >10 MM bbl/yr	64	124	117	305	196,000
D.	Gasoline Crude oil	>5 MM bbl/yr >100 MM bbl/yr	61	105	99	265	177,000
E.	Gasoline Crude oil	>10 MM bbl/yr >100 MM bbl/yr	61	96	91	248	163,000

[a]Terminals affected by proposed or promulgated state regulations are not included in the above emission estimates, with the exception of terminals located
in Alaska. Assumes Alyeska uses incineration.

5.0 ECONOMIC IMPACT ANALYSIS

This chapter contains estimates of the economic impact of five regulatory alternatives for controlling emissions from loading operations at marine terminals. The analysis is performed in conformity with Executive Order 12291, the Regulatory Flexibility Act and within an economic analysis framework explained in the methodology section. Economic impacts of the proposed regulatory alternatives estimated in this analysis include: price changes, output and market shifts, and potential small business and employment impacts.

This chapter is organized as follows. Section 5.1 is a summary of the impacts. Section 5.2 is a description of the methodology utilized in estimating impacts. Section 5.3 defines the coverage of the industry regarding economic impacts. Sections 5.4 through 5.7 cover the impact categories in the order of prices, market impacts, small business and employment. Section 5.8 describes concurrent legislation and regulations affecting the marine industry. Section 5.9 considers fifth-year projections.

5.1 SUMMARY OF ECONOMIC IMPACT ANALYSIS

This analysis estimated the economic impacts of air emission controls on marine vessel loading operations. Price, output and employment effects for affected products and for the marine transport industry were examined. Potential small business impacts were also isolated. Since these impacts differ considerably from one regulatory alternative (RA) to another,

Table 5-1 was constructed to facilitate the discussion of these differences. Table 5-1 reports impact information for the scenario with all terminals impacted except those covered by present regulations in California, Louisiana, New Jersey, and Pennsylvania.

Maximum price increase levels summarized in Table 5-1 for the affected products would not be significant across all regulatory alternatives. Under RA A the increases average 1 percent (ranging to 1.8 percent) but decrease quickly to 0.2 to 0.6 percent under the other four RA's.

Corresponding with small price changes are small output and employment changes. Most of the affected products have moderately inelastic to very inelastic demand which permits control costs to be passed on to consumers without much change in their buying behavior.

Although pipeline transport has taken market share from affected products over the past years, it is expected that this regulation will only cause very small additional shifts to pipeline transport. Maximum increases in marine loading and transport prices are estimated in the range of 15 to 37 percent for crude oil and products under RA A and 2 to 14 percent under RA B through RA E. The cost of marine transport compared to the final product price is relatively small which accounts for the larger percentage increases for the marine transport sector.

Increases associated with RA B through RA E are not likely to be high enough to cause the building of new pipelines. In addition, the marine transport price increases at the higher end of the price increase range are for small quantities which are not economical for pipeline transport unless the firm already has unused pipeline capacity. The increases under RA A would cause more significant shifts of shipments by pipelines or other transport modes.

The most noteworthy potential impact of the most stringent regulatory alternatives considered concerns the smallest terminals that could be required to control, since control costs per unit of throughput for small terminals are very high compared

TABLE 5-1. SUMMARY OF IMPACTS BY REGULATORY ALTERNATIVE

Reg. Alt.	Terminals covered/ throughput, MM (BBL's/yr)	Total cost, MM	Maximum percent price increases	Percent output reductions	Employment reductions	No. of terminals under competitive pressure	Impact on vessels	Displacement potential by pipeline
A	All	750	0.3-1.8	0.07-0.26	924	> 1,000	High level of dedication to regulated products	Some in long run
B	Gasoline >0.5 Crude >5.0 Alcohols >1.5 Toluene >10.0	100	0.36 0.32 0.60 0.41	0.03 ND 0.04	165	0-65	Significant level of dedication	Minimal
C	Gasoline >1.0 Crude oil >10.0	79	0.29 0.31	0.02 ND	119	0-30	Moderate level of dedication	Minimal
D	Gasoline >5.0 Crude oil >100	51	0.21 0.18	0.02 ND	<50	0-5	Low level of dedication	Minimal
E	Gasoline >10.0 Crude oil >100	41	0.19 0.18	0.02 ND	<50	0	Low level of dedication	Minimal

ND = Not determinable, function of other products derived from crude oil.

to larger terminals. This could cause some of these terminals to lose the business of storage and loading these regulated products. The terminals would not necessarily go out of business, but would have to seek other business at perhaps lower profitability levels. If RA A were chosen, greater than 1,000 terminals would face such competitive pressure and most of those terminals are small.

For RA B through RA D the analysis showed 65, 30, and 5 terminals that have high average control costs compared to the other terminals that would be controlled. Under perfectly competitive markets where there were substitute terminals available, those 65, 30, and 5 terminals in RA B through D would be under competitive pressure to switch loading operations to uncontrolled products, reduce throughput below the cutoffs, or shift business to other less costly terminals that either exist nearby or could theoretically be built nearby.

However, several factors exist which make this a market with less than perfect substitution of terminals. The majority of terminals in RA B through RA D are likely part of much larger integrated petroleum companies which may choose to absorb the higher than average control costs rather than transfer loading to an independent terminal. Second, some or all of those higher than average control costs will be offset by the added costs to transfer the product to what would invariably be a further terminal. Third, some substitute terminals would either have to be very large to have significantly lower control costs or there would have to be one or more nearby small unregulated terminals. For these reasons the actual number of terminals expected to stop loading the controlled products is smaller than what the competitive market analysis shows.

The primary impact on marine vessels will likely be that the low-retrofit cost vintages of tankers and barges will be dedicated to transporting the regulated products. Other vessels will lose the business of transporting the regulated products and will need to obtain the business in nonregulated products formerly carried on the dedicated vessels.

Under RA D, small business impacts are not expected to be significant. The terminals affected by RA D will primarily be owned by integrated petroleum facilities which tend to be large. Similarly, RA D will only affect a moderate portion of the vessel fleet that will transport regulated crude oil and petroleum products. The portion affected will likely be large, lower-cost retrofit vessels and the retrofit costs of $0.002 per barrel for crude and $0.030 for products should not cause a significant impact.

In terms of total control costs, RA A would be far more costly (estimated at $750 million) than any of the other RA's. Regulatory Alternative D has an estimated total cost of $51 million.

If these three facilities become eligible for exemption the total cost under RA D would reduce from $51 million to $22 million. The reduction of $29 million equates to $0.03 per barrel or $0.0007 per gallon. Thus while total costs would reduce significantly if such exemptions occur, the percent price increases for final products will not change significantly.

5.2 METHODOLOGY FOR ESTIMATING ECONOMIC IMPACTS

The purpose of estimating economic impacts is to provide EPA decision-makers with information as to who bears the costs and impacts of the proposed regulatory alternatives and in what magnitude or with what consequences. The imposition of costs on one industrial sector may cause that sector to change behavior with regard to the prices it charges, its level of supply to the market or the makeup of the resources it utilizes to provide the supply. These behavioral changes may cause impacts on other sectors as well as on consumers of the output of that sector. The objective of the analysis is to trace significant changes through the impacted sections to the consumers, and to measure the magnitude and consequences of the impact.

The general methodology for this analysis is to first derive the increase in price that petroleum and chemical producers will face to transport their products by marine facilities subject to the regulation. This derivation of price increase will include

factors for the control costs incurred by the marine terminals and the control costs incurred by the marine vessels. Separate calculations will be performed for crude oil and products; the latter defined as refined petroleum products or chemicals. Since marine transport faces competition from pipelines and to some extent railroads and trucks, the analysis then focused on whether or not the cost increases of this regulation would cause an erosion of the transport market share held by the marine sector.

The next step in the analysis is to determine if certain terminals or vessels are not expected to retrofit with the control options because either the impacts on their profits are prohibitive or because their customers refrain from shipping by marine because of the control costs. This situation primarily arises because of the significant control cost differentials per terminal by size of throughput and for marine vessels because of the higher annualized costs for older vessels.

Next, the likely price increases for the product consumptive markets will be calculated and an analysis performed of the economic impact of these increases. Output changes will be calculated from assumed or derived price elasticity coefficients. Employment effects from these output changes will also be estimated.

Potential small business impacts will then be isolated from the above impact analysis. Impacts on small businesses depend on decisions by EPA regarding the threshold level of terminal throughput or products controlled by the regulation, i.e., which regulatory alternative is chosen.

Concurrent legislation impacting the regulated products will be examined. The influence that those regulations have on the baseline or the impacts of this analysis will be considered.

Finally, consideration will be given to how impacts might change as a function of what is expected to occur five years from now in the affected sectors.

The five regulatory alternatives considered in this analysis consist of combinations of crude oil, gasoline and products that emit volatile organic compounds and hazardous air pollutants at

facilities of varying size throughput. The alternatives are as follows:

A. All Terminals

B. Gasoline >500K bbl/yr, Crude Oil >5MM bbl/yr, Toluene 0.5MM bbl/yr and Alcohols >1.5 MM bbl/yr

C. Gasoline >1MM bbl/yr, Crude Oil >10MM bbl/yr

D. Gasoline >5MM bbl/yr, Crude Oil >100MM bbl/yr

E. Gasoline >10MM bbl/yr, Crude Oil >100MM bbl/yr

Regulatory Alternatives A and B are the only alternatives that directly cover chemicals and products other than gasoline and crude oil.

5.3 GROUNDRULE FOR ECONOMIC IMPACT OF THIS REGULATION

Economic impact of a regulation is defined as that impact arising from the incremental expenditures that are attributable to the regulation and which would not have been undertaken were it not for the presence of the regulation. Incremental expenditures are those expenses above and beyond what the regulated members incur due to their own economic choices or due to that required by other regulations.

In this instance several States have already promulgated or proposed regulations to control VOC emissions from marine terminal loading of petroleum products and other VOC emitting products. These states include California, Louisiana, New Jersey, Alaska, and Pennsylvania. Alaska's regulations however might not require controls before this regulation takes effect. This analysis will therefore treat the Alaska terminals as being uncontrolled.

The presence of these state regulations, from an economic viewpoint, means that the impact of national regulations consists of the impacts in states where such regulations do not exist and the impact where the national regulations are more stringent or more comprehensive than the existing state marine terminal VOC control requirements. Thus if these state regulations are assumed to take effect before the forthcoming national regulation and are as stringent as the national regulation, the economic impact of the national regulation will consist primarily of the

impact created in states other than California, Louisiana, New Jersey, and Pennsylvania. The baseline for this analysis is significantly affected by these state regulations since a significant amount of marine-loaded crude oil and products are loaded in these four states.

With regard to specific economic impacts the definition means that the total costs of the regulation are lessened considerably because of existing regulations in these states. However, this operational definition does not always reduce the impacts on price and output of those products impacted by this regulation. For example, the price increases for the crude oil or gasoline controlled at marine facilities in a state such as Ohio may still be the same even though the already-regulated states listed above are not being counted. Thus there will be fewer marine terminal loadings counted as being affected by this regulation but for those that are counted, the relative size of impact may be the same as if all loadings are counted.

5.4 POTENTIAL PRICE INCREASES

The initial impact of consideration is by how much will the prices of the controlled products increase as the marine terminal and vessel owners pass portions or all of the control cost onto the product producers who, if market conditions allow, pass those costs onto consumers. Separate potential price increase calculations are presented for each of the regulated products or groups of products under each regulatory alternative. Later on, market reactions to such price increases are estimated.

For the products subject to this analysis we are assuming full control cost pass through in the long run. This is equivalent to assuming a perfectly competitive market environment. For these products, barriers to entry are not insurmountable, and domestic and foreign competition is present in sufficient amounts to support this assumption. To the extent that imperfect competition exists in the industries affected by this regulation, not all of the control costs will be passed through in the form of higher consumer prices.

5.4.1 Crude Oil

Table 5-2 is constructed to show what the potential price increases might be for barrels of crude oil sold to petroleum refineries. These price increase estimates are based upon the average control cost for each regulatory alternative (RA) under full-cost pass through conditions. Table 5-2 shows that RA A has average control costs of $0.12 per barrel whereas RA B is $0.04 per barrel, RA's C, D, and E are $0.03 per barrel. On this basis the costs of RA A are four times greater than RA's D and E.

With respect to the percent price increases for crude oil represented by these control costs per barrel, Table 5-2 also shows percentage increases based upon two crude oil prices per barrel. Just prior to the Iraq invasion of Kuwait the price per barrel of oil was $17 to $18.[1] Price ranges for crude oil since then have been from $20 to $39 with more recent prices in the lower $20's. Table 5-2 shows the percent price increase for two price levels, $17 and $30.

Regulatory Alternative A would produce a 0.7 percent price increase when crude oil is $17 per barrel and a 0.4 percent increase at $30 per barrel. The corresponding increases for RA B are 0.2 percent and 0.1 percent. For RA C the percent price increases are 0.2 and 0.1. For RA's D and E the percent price increases also 0.02 and 0.01, respectively. As will be shown later it is the high per unit control costs for all the small terminals in RA A that causes the average cost increases to be several times higher than the costs for the larger terminals covered by RA's B thru E.

In absolute terms, even a price increase of 0.7 percent for RA A may not initially appear to be an increase that would cause much of an economic impact for petroleum refineries and their customers. However, what is expected to happen under RA A is that small terminals would lose business to larger terminals because of the significant control cost differential by size of terminal. Thus actual cost increases would not be 0.7 percent but a lower number somewhat higher than for RA B which is 0.2 percent.

TABLE 5-2. CONTROL COSTS AND PRICE INCREASE PER BARREL CALCULATIONS FOR CRUDE OIL REGULATORY ALTERNATIVES

Reg. Alt.	Size throughout terminals	Throughput volumes, bbl/yr	Annualized control costs	Average control cost/bbl throughput	Percent potential price increase	
					$17/bbl, %	$30/bbl, %
A	All	1,384,201,353	163,291,710	0.1180	0.694	0.393
B	>5 MM bbl/yr	1,229,557,464	43,034,290	0.0350	0.206	0.116
C	>10 MM bbl/yr	1,199,270,954	39,919,760	0.0333	0.196	0.110
D	>100 MM bbl/yr	883,329,116	29,300,000	0.0301	0.177	0.100
E	>100 MM bbl/yr	883,329,116	29,300,000	0.0301	0.177	0.100

Using individual terminal data for the Case 6 series model facilities it can be shown how economics of scale for control cause small plants to have large control costs per barrel vis-a-vis large plants. Table 5-3 shows the large range in control cost per barrel for terminals. The range in RA A is far broader than within the other RA's. Terminal owners who would have to charge $1.00 per barrel under RA A will lose business to terminal owners who only need to charge $0.14 per barrel to recover their costs, (maximum under B) or $0.06 or less per barrel (under RA C, D and E) as long as either excess capacity exists in the large terminals or new large terminals are built. The other economic variable that would prevent many crude oil producers from passing on the differential control costs under RA A is the presence of crude oil import potentials. In 1989 the U.S. imported 2.217 billion barrels of crude oil according to the Petroleum Supply Annual report. The incremental crude oil throughput of RA A over RA B is 1,384,201,353 barrels less 1,229,557,464 or 154,643 barrels per year (from Table 5-2). This amount is about 7 percent of the 1989 level of imports; an amount within the capacity of foreign producers and transporters to readily supply.

The present cost to transport crude oil from the middle east to the U.S. averages $2.65/barrel with a range of $0.88 to $5.30 depending on the availability of vessels.[2] In theory it can be expected that increases in crude oil shipments of 7 percent will bear a slight increase in marginal costs of perhaps 1 or 2 percent for refinery owners. At $20 per barrel plus $2.65 for shipping, a 2 percent increase is 0.02 x $22.65 or $0.05 per barrel. This incremental cost of marginally imported crude oil is greater than the vapor control cost of RA B ($0.04 per barrel), RA's C, D and E ($0.03 per barrel) but well less than the average increase of $0.12 under RA A. Thus petroleum refiners would find it less costly to import more crude oil than to pay the control costs of RA A.

TABLE 5-3. CONTROL COST PER BARREL CALCULATIONS FOR CRUDE OIL MODEL FACILITIES AND REGULATORY ALTERNATIVES

Reg. Alt.	Size throughput terminals	Range of control cost, $/bbl			Throughput volumes, bbl/yr	No. terminals
		6	6B	6C		
A	All	0.005-16.433	0.121-0.148	0.158-114,935	1,384,201,353	201+
B	>5 MM bbl/yr	0.005-0.272	0.121-0.137	NA	1,229,557,464	8
C	>10 MM bbl/yr	0.005-0.056	NA	NA	1,199,270,954	5
D	>100 MM bbl//yr	0.006-0.056	NA	NA	883,329,116	3
E	>100 MM bbl/yr	0.006-0.056	NA	NA	883,329,116	3

Case 6 = All terminals loading crude oil to ship.s
Case 6B = Terminals with crude oil throughput of greater than 4 MM bbl/yr but less than 8 MM bbl/yr.
Case 6C = Terminals with crude oil throughput of less than 4 MM bbl/yr.

5.4.2 Potential Price Increases for Marine Transport of Crude Oil

The cost of storage, loading, transporting and unloading crude oil in the U.S. ranges from $1.10 to $2.30 per barrel depending on the type of crude oil, length of trip, size of vessel, etc.[3] From Valdez, Alaska to the lower west coast the transportation cost averages $1.25 per barrel with a range of $1.10 to $1.50 per barrel.[3] The storage and loading cost is another $0.25 to $0.50 per barrel with an average of $0.30.[3] From the Gulf Coast (Louisiana and Texas) to the east coast the transportation cost is $0.80 to $0.90 per barrel south of Cape Hatteras and $1.20 per barrel north of Cape Hatteras.[3] From Panama to the east coast the cost is $2.00 per barrel.[3] Again the storage and loading costs of $0.25 to $0.50 per barrel needs to be added to obtain total marine costs.[3]

The data in Table 5-4 shows that average marine transport costs for crude oil, when all terminals are controlled under RA A will increase 6.54 percent to 10.73 percent. Producers using large terminals handling more than 5MML bbl/yr will face increases from 1.94 percent to 3.18 percent. Producers using terminals handling more than 10 MML bbls/yr will face increases from 1.85 to 3.03 percent and the largest terminals face a 1.67 to 2.74 percent increase.

5.4.3 Potential Price Increases for Final Products from Crude Oil

The next part of the analysis examines how these potential control costs for crude oil will be allocated to the products derived from crude oil. Table 5-5 shows that when any combination of control cost per barrel of crude oil is spread over all the products that a barrel of crude oil yields, the price increases per gallon are all very small, i.e., well less than 1 cent per gallon. Table 5-5 was calculated using the average control cost for each RA. For example, the 11.80 per barrel increase for RA A equates to $0.0028 per gallon (42 gallons per barrel). Since gasoline is 44.67 percent of the yield from crude oil its proportionate share of the $0.0028 per

TABLE 5-4. POTENTIAL PERCENTAGE PRICE INCREASES IN MARINE TRANSPORT FOR CRUDE OIL

Reg. Alt.	Average control cost per barrel	Percent price increase	
		$1.10	$1.80
A	$0.1180	10.73	6.56
B	$0.0350	3.18	1.94
C	$0.0333	3.03	1.85
D	$0.0301	2.74	1.67
E	$0.0301	2.74	1.67

TABLE 5-5. POTENTIAL PRICE INCREASES FOR PRODUCTS PRODUCED FROM CRUDE OIL

Commodity	Yield in gallons	Percent of total	Regulatory alternatives			
			A	B	C	D & E
			(Average cost increase$/bbl)			
			0.1180	0.0350	0.0333	0.0001
			(Average cost increase $/gln)			
Gasoline	19.7	44.67	0.0013	0.0004	0.0004	0.0003
Distillate	9.0	20.41	0.0006	0.0002	0.0002	0.0002
Jet Fuel	3.8	8.62	0.0002	0.0001	0.0001	0.0001
Residual	3.0	6.80	0.0002	0.0001	0.0001	0.0001
Still Gas	1.9	4.31	0.0001	0.0000	0.0000	0.0000
Coke	1.5	3.40	0.0001	0.0000	0.0000	0.0000
Feedstocks	1.2	2.72	0.0001	0.0000	0.0000	0.0000
Asphalt	1.3	2.95	0.0001	0.0000	0.0000	0.0000
LP Gas	1.2	2.72	0.0001	0.0000	0.0000	0.0000
Lubricants	0.6	1.36	0.0000	0.0000	0.0000	0.0000
Kerosene	0.4	0.91	0.0000	0.0000	0.0000	0.0000
Miscellaneous	0.5	1.13	0.0000	0.0000	0.0000	0.0000
Total	44.1[a]	100.00	0.0028	0.0008	0.0008	0.007

[a]Crude oil per barrel is 42 gallons; gain to 44.1 gallons from hydrogen processing gains.

Source: National Petroleum News Factbook Issue, 1986, p. 147.

gallon is $0.0013. Similar to earlier analyses RA A induces larger cost increases for crude oil products than RA's B thru E. However in all cases potential price increases are all less than one cent per gallon.

Later-on these price increases will be added to those of the petroleum products directly controlled to eventually estimate market impacts.

5.4.4 Potential Product Price Increases

In line with the analysis performed on crude oil, Table 5-6 presents potential price increase estimates for the regulatory alternatives affecting gasoline, chemicals and other noncrude oil products covered by the potential regulations. The data in Table 5-6 shows how, in the far right column, the average control cost per gallon reduces significantly from RA A to RA E. The cost in RA A averages 1¢ per gallon ($0.0098) whereas the cost for RA D and RA E is 0.2¢ per gallon. The throughput and total control cost for RA A is also much more than for the other regulatory alternatives. Toluene and methanol would be controlled under RA A at all size terminals and under RA B at terminals with throughput of greater than 500,000 barrels per year. Under RA A the average control cost for toluene is 1 cent per gallon and 0.6 cent per gallon under RA B. The corresponding control cost averages for alcohols, as represented by methanol, are $0.0098 per gallon for RA A and $0.0031 per gallon under RA B.

Table 5-7 converts the average control cost per gallon into percentage price increases for the various products, excluding the control costs passed-on from the direct control of crude oil. Gasoline is the only product covered under all the regulatory alternatives. Under the most comprehensive regulatory alternative, A, the percent increase for gasoline is 0.9 percent whereas for RA B through RA E the estimated increasese are 0.3 percent to 0.2 percent.

For toluene the estimated price increases are 0.7 percent for RA A and 0.4 percent for RA B. The price increases for methanol are 1.78 percent for RA A and 0.60 percent for RA B.

TABLE 5-6. POTENTIAL PRODUCT PRICE INCREASES FOR THE VARIOUS REGULATORY ALTERNATIVES

Reg. Alt.	Products covered	Barrels product throughput	Total annualized cost	Average control cost/BBl	Average control cost/Gln
A	All	1,409,182,523	578,731,577	0.4107	0.0098
B	Gasoline	353,254,896	51,888,245	0.1469	0.0035
	Toluene	7,984,381	1,963,286	0.2459	0.0059
	Alcohols	22,784,510	3,192,820	0.1401	0.0033
C	Gasoline	331,614,783	39,525,863	0.1192	0.0028
D	Gasoline	256,324,426	22,000,000	0.0858	0.0020
E	Gasoline	162,905,309	12,300,000	0.0755	0.0018

All = Gasoline, alcohols, naptha, jet fuel distillate, toluene.

TABLE 5-7. POTENTIAL PRICE INCREASES FOR PRODUCTS

Gasoline	Price/gal, $	Average control cost/gallon					Potential percentage price increase				
		A	B	C	D	E	A	B	C	D	E
Gasoline	1.10 (July 1990)	0.0098	0.0035	0.0028	0.0020	0.0018	0.89	0.32	0.25	0.18	0.16
Jet fuel/ kerosene	0.59 (1989)	0.0098	--	--	--	--	1.66	--	--	--	--
Naphtha	1.40 (1990)	0.0098	--	--	--	--	0.70	--	--	--	--
Distillate	0.87 (1989)	0.0098	--	--	--	--	1.13	--	--	--	--
Toluene	1.42 (1990)	0.0098	0.0059	--	--	--	0.69	0.41	--	--	
Ethylene glycol	3.34 (1990)	0.0098	--	--	--	--	0.29	--	--	--	--
Methyl ethyl ketone	2.14 (1990)	0.0098	--	--	--	--	0.46	--	--	--	--
Methanol	0.55 (1990)	0.0098	0.0033	--	--	--	1.78	0.60	--	--	--

Source: (Gasoline) JACA estimates; (Jet Fuel/Kerosene) - U.S. Department of Energy, Energy Information Administration, Annual Outlook for Oil and Gas, 1990, p. 29; (Naphtha) - Chemical Marketing Reporter, October 26, 1990, p. 34; (Distillate) - U.S. Department of Energy, Energy Information Administration, Annual Outlook for Oil and Gas, 1990, p. 29; (Toluene) - Chemical Marketing Reporter, October 26, 1990, p. 46; (Ethylene Glycol) - Chemical Marketing Reporter, October 26, 1990, p. 41; and (Methyl ethyl ketone) - Chemical Marketing Reporter, October 26, 1990, p. 43. Methanol (for alcohols) - Chemical Marketing Reporter, December 31, 1990, p. 71.

For the other products covered by RA A the estimated increases range from a low of 0.3 percent for ethylene glycol to a high of 1.7 percent for jet fuel and kerosene.

5.4.5 Combined Potential Product Price Increases

To determine the true market price increase for the various petroleum and chemical products, it is necessary to combine the derived price increases from crude oil plus the direct control cost price increases for the products. Because of the very small increases associated with crude oil it is only meaningful to show the combined effect for gasoline, distillate, methanol and toluene in Table 5-8. For gasoline, the crude oil costs add a 0.12 percent price (up to 1.01 percent) under RA A and 0.04 percent or less for RA B through RA E. For distillate the price increase under RA A from adding crude costs is a plus 0.07 to 1.20 percent and a plus 0.02 percent for RA D. For methanol the increases from crude oil are 0.02 and less. For toluene the increases from crude oil are 0.01 percent or less.

5.4.6 Potential Price Increases in the Costs for Marine Transport of Products

Petroleum products are primarily moved from refineries to markets by pipeline or by marine vessels. As the petroleum products get closer to their final destination the shipments become smaller and are moved primarily by rail or by truck.

Marine transport of products is conducted along all the coastal routes, i.e., west coast, gulf coast and east coast. This movement can be by ship or by large-sized barges. Petroleum products moved on inland waterways are usually performed by barges. Ships can go up the Hudson River to Albany but that is one of the few inland waterways that ships can travel.

Marine transport of products is generally performed by ships or barges that are dedicated to carrying "clean" products. The cost to transport and unload clean products on the ocean or on inland waterways ranges from $0.80 to $1.30 per barrel.[3] The storage and loading costs average $0.30 per barrel with a range of $0.25 to $0.50.[3] The loading costs alone only range from

TABLE 5-8. COMBINED POTENTIAL PRICE INCREASES FOR SELECTED PRODUCTS

Reg. Alt.	A	B	C	D	E
Gasoline					
Product control only, %	0.89	0.32	0.25	0.18	0.16
Combined with crude oil, %	1.01	0.36	0.29	0.21	0.19
Distillate					
Product control only, %	1.13	--	--	--	--
Combined with crude oil, %	1.20	0.02	0.02	0.02	0.02
Toluene					
Product control only, %	0.69	0.41	--	--	--
Combined with crude oil, %	0.70	0.41	0.00	0.00	0.00
Methanol (alcohols)					
Product control only, %	1.78	0.60	--	--	--
Combined with crude oil, %	1.80	0.60	0.00	0.00	0.00

$0.05 to $0.07 per barrel; however, storage costs for a month range from $0.25 to $0.30.[3]

The potential price increase percentages for marine transport of product caused by the control requirements is shown in Table 5-9. The price increases for marine transport (including loading, transport, unloading and storage) range from 27.4 to 37.4 percent under RA A. For RA B the increases range from 9.9 percent to 13.6 percent. For RA C the range is 7.9 to 10.8 percent. For RA D and RA E the price increase percentages range between 5 to 8 percent.

5.5 MARKET IMPACTS

Based upon the average control cost per gallon and percentage price increase figures derived above, estimates will be made in this section of any reductions in output in the affected sectors that could result from increased control costs for marine-loading of regulated products. The concern about output changes are with shifts in resources caused by plant closures and reductions in employment associated with the reduced output as well as with reduced value of production. Output reductions will occur to the extent that firms cannot pass control cost increases on to consumers or because consumers react to higher product prices by buying less. Output changes among members of a sector will also be considered, i.e., the distributive effects.

In this economic impact analysis there are three sectors where market impacts are possible: marine terminals, marine vessels, and regulated product producers.

5.5.1 Marine Transport Versus Pipeline

The major competition to marine transport of petroleum products is from pipeline transport. Over the years the share of the market occupied by pipeline has increased significantly. The question in this analysis is whether these control costs will cause a further shift from marine to pipeline. Short run versus long run considerations are involved.

In the short run it is not expected that shifts to new pipelines will occur. There is recent empirical evidence for

TABLE 5-9. POTENTIAL PRICE INCREASES FOR MARINE TRANSPORT OF PRODUCTS

Reg. Alt.	Costs per barrel[a]	Percentage price	
		$1.10	$1.50
A	$0.411	37.36	27.40
B	$0.149	13.55	9.93
C	$0.119	10.82	7.93
D	$0.086	7.82	5.73
E	$0.076	6.91	5.07

[a]Average control cost per size throughput range.

this. Marine transport costs increased significantly during the Kuwait invasion because diesel costs had increased. Since it takes less energy per unit to transport by pipeline than marine, the cost of marine transport relative to pipeline had increased. The relative increase associated with the diesel fuel increase was probably larger than the projected relative increase for these control costs. During this time period all of the surveyed petroleum companies and marine transport companies indicated that no shift to pipeline had taken place. The reasons for the lack of shift are essentially that pipelines have reached equilibrium with routes that are fixed and they are increasingly difficult to build. Not only is there high capital cost required for pipeline construction but the process to obtain the necessary permits is becoming more difficult due to heightened awareness over environmental concerns and right of way problems.

In the long run it is not likely that further shifts to pipeline will occur as an impact of the vapor control costs of RA B thru RA E. In this case, long run means greater than 8 years, i.e., the time to obtain approval for and build new pipelines.[3] The pipeline building trend seems to have peaked.[3] Newer pipelines will cost more to build because of environmental concerns, siting resistance, and hillier terrains.[3] Another reason is that pipelines require large volumes of product to be shipped in order to pay for the large initial capital outlays. Increases in marine transport costs for the larger volumes of transported products are around 5 to 14 percent under RA B thru RA E. At such a relative price increase level pipelines will not likely be built to try and capture that market.

It is likely however, that the 27.4 to 37.4 percent increase under RA A for buying marine transported products could be significant enough to cause some displacement by pipeline provided enough volume is being transported at those price increase levels over a long period of time to warrant building a pipeline. The increases for RA B through RA E are considerably smaller and far less likely to cause such displacement.

This question is also intertwined for crude oil and products with the impact of the Oil Pollution Act of 1990 on marine transport (see Section 5.7.2) and transport insurance requirements. On the one hand the combined effect of vapor controls, spill liability and double-hull requirements may be enough to cause a further shift to pipeline. On the other hand, for the small number of crude oil loading terminals likely to be installing controls most of them probably do not compete with pipelines because the cost of establishing a pipeline is prohibitively high, e.g., from Valdez, Alaska to Washington, Oregon, or California and requires large volumes of throughput.

5.5.2 Marine Terminals

Marine terminal output reductions could occur in two ways. The first is through reductions in final demand for the products (see Section 5.5.4). Second, the large differential control costs per terminal under some of the regulatory alternatives could cause some terminals to not install control systems and therefore not take business loading crude oil, petroleum products and regulated chemicals. This impact will be explored in this section.

Normally, if one firm gives up business to another firm there is no output change. However, if the control cost differential is so large in places where multiple terminals do not readily exist, it could lead to some producers of petroleum products not being able to economically bring their product to market. In the meantime, demand would be met through increases in supply from other sources, domestic and foreign.

According to 1988 preliminary data from the Waterborne Commerce of the United States, throughput at terminals ranged from a high of 228,014,897 bbl/yr to as little as 6 bbl/yr, realizing a total of 1.9 billion bbl/yr for 1988.

Currently, terminal facilities located in the Santa Barbara channel, the San Francisco Bay area, and the States of Louisiana, New Jersey, and Pennsylvania are required, or are proposed to be required, to recover or dispose vapors when loading tankers with crude oil and gasoline by 1991 and 1992, respectively.

At each port, there can be a number of terminals competing for business. Utilization of terminal capacity ranges from 20 to 85 percent with no meaningful average.[4] This industry is so competitive that even those companies who are well entrenched with one facility call around regularly for quotes on storage and loading costs. However, there is some evidence shown by both customers and terminallers that they want to enter into longer term contracts, usually a minimum of 1 year.[5] For purposes of choosing the most appropriate terminal, a commodity owner needs to consider if a pipeline is nearby or if a ship can be rerouted to another terminal.

Marine terminals, even though primarily privately owned, are called either private and public. Private terminals are owned by major oil companies who are vertically-integrated in the distribution of their products. A significant portion of these companies also own liquid bulk terminal facilities not only at the marine terminals but at points closer to the final refined product destination. Public terminals are for-hire facilities where terminallers do not take ownership of the material. They provide storage for a third party, who typically handles the movement of the product to and from the terminal as well as the specifics of the marine or pipeline transport. The supply and demand of these facilities directly depend on the supply and demand experienced in the oil business.

In an effort to widen margins, a number of services are offered by terminallers, for example, storage capacity, transfer responsibilities for moving the product in and out, cleaning services performed on the tank after product removal, filtration of product such as jet fuel and waste handling services. The number of employees at terminals depends on capacity, amount of inventory moving in and out, and the type of product. Typically, petroleum storage is less labor intensive.

Special services like breakbulk repacking might be offered for products like glycol for the antifreeze market. Special equipment is available like chillers, nitrogen blankets to keep

moisture out, and special linings for tanks or pipelines to maintain product integrity.

In addition, demurrage rates are charged if they are needed. They are assessed if a vessel or terminal exceeds the allotted time for a loading or unloading operation. It is a preagreed rate that is charged for the amount of time in excess to the preagreed allowed time.

As just analyzed pipeline competition is not expected to take away marine terminal business. However, the large differences in control costs among terminals are expected to cause some small terminal owners to not install control systems and to lose this business. This potential impact on small entities will be examined below.

The EPA Regulatory Flexibility Act Guidelines describe steps for determining whether a regulatory flexibility analysis (RFA) needs to be performed. The test is if a significant economic impact is expected to occur on a substantial number of small entities. The affected sectors for which this will be performed in this analysis will be marine terminals and marine vessels. The SBA definition of small marine cargo handling entities is $12.5 million sales or less. Terminals perform business transferring many commodities including others that are not regulated herein and are often part of much larger companies. Nevertheless this standard will be used in the analysis.

The size distribution of terminals handling petroleum products and chemicals is as follows. As the data shows 73.8 percent of the terminals (i.e., those less than 500,000 barrels throughput) would only be subject to control under RA A.

Terminals loading petroleum products	
Barrels/yr	Percent of total
>10,000,000	3.0
8-9,999,999	0.7
6-7,999,999	1.4
4,5,999,999	2.5
2-3,999,999	5.0
1-1,999,999	6.1
0.5-999,999	7.5
<500,000	73.8
	100

For illustrative purposes, we have chosen level of 4,000,000, 2,000,000, 1,000,000, and 500,000 barrels per year to determine the relationship of size facility to impacts.

To obtain further insight into the question of size businesses, data was examined for SIC 4491, Marine Cargo Handling. This SIC includes public terminals doing business with many producers as opposed to just the producer who owns them. 1988 County Business Patterns data (Table 5-10) shows 834 establishments in this SIC. Of this number, some will be owned by large businesses and some will already be subject to emission controls under state regulations. Some will also not be transferrers of petroleum and chemical products. It is also unclear how many of these terminals would be controlled under each RA. Of the 1,777 terminals subject to RA A the SIC 4491 data would indicate that less than one-half of the terminals are public terminals.

Table 5-10 shows the distribution of the SIC 4491 terminals by state. Louisiana, Texas, Florida, and California have the most terminals, respectively. The table also shows the number of employees per establishment. The U.S. average for SIC 4491 is 68 employees per establishment.

TABLE 5-10. 1988 COUNTY BUSINESS PATTERNS BY STATE FOR SIC 4491 (Marine Cargo Handling)

	Total establishments	Total No. of employees (mid-March)	Employees per establishment	Total annual payroll, $1,000's	Pay per employee, $1,000's
Alabama	19	693	36.5	1,231	16.21
Alaska	10	388	38.8	15,153	39.05
Arizona			0.0		0.00
Arkansas	11	100[a]	9.1	0a	0.00
California	60	9,104	151.7	437,617	48.07
Colorado			0.0		0.00
Connecticut	3	250[a]	83.3	0[a]	0.00
Delaware	6	250[a]	41.7	0[a]	0.00
District of Columbia			0.0		0.00
Florida	78	5,144	65.9	84,377	16.40
Georgia	19	1,862	98.0	22,208	11.93
Hawaii			0.0		0.00
Idaho			0.0		0.00
Illinois	40	968	24.2	23,408	24.18
Indiana	8	108	13.5	3,781	35.01
Iowa	4	20[a]	5.0	0[a]	0.00
Kansas			0.0		0.00
Kentucky	22	436	19.8	11,622	26.66
Louisiana	104	6,031	58.0	112,500	18.65
Maine			0.0		0.00
Maryland	25	2,907	116.3	91,396	31.44
Massachusetts	11	810	73.6	15,387	19.00
Michigan	7	67	9.6	3,412	50.93
Minnesota	12	20[a]	1.7	0[a]	0.00
Mississippi	9	494	54.9	8,469	17.14
Missouri	13	272	20.9	6,603	24.28
Montana			0.0		0.00
Nebraska			0.0		0.00
Nevada			0.0		0.00
New Hampshire			0.0		0.00
New Jersey	32	3,507	109.6	122,860	35.03
New Mexico			0.0		0.00
New York	40	1,864	46.6	49,158	26.37
North Carolina	12	1,006	83.8	12,055	11.98
North Dakota			0.0		0.00
Ohio	31	1,097	35.4	35,947	32.77
Oklahoma	3	20[a]	6.7	0[a]	0.00
Oregon	19	1,000[a]	52.6	0a	0.00
Pennsylvania	21	1,692	80.6	46,411	27.43
Puerto Rico			0.0		0.00
Rhode Island			0.0		0.00
South Carolina	23	2,563	111.4	50,935	19.87
South Dakota			0.0		0.00
Tennessee	11	97	8.8	1,714	17.67
Texas	93	6,125	65.9	81,422	13.29
Utah			0.0		0.00
Vermont			0.0		0.00
Virginia	17	2,720	160.0	66,721	24.53
Washington	39	3,054	78.3	147,249	48.22
Wisconsin	11	147	13.4	6,557	44.61
West Virginia	8	129	16.1	3,077	23.65
Wyoming	8		0.0		0.00
TOTAL (Above):	821	54,945	66.9	1,471,270	26.78
TOTAL (Dialog):	834	56,741	68.0	1,618,041	28.52
Difference:	13	1,796		146,771	28.52

NOTE: These figures exclude government employees, except self-employed employees

[a]When there are only a few establishments in a county for an industry, total annual payroll figures and the total number of mid-March employees are sometimes withheld to avoid the disclosure of information about individual establishments. Withheld payroll figures are indicated by an 0. However, the employment size class is shown in substitution for the total number of mid-March employees.

Reference: 1988 County Business Patterns, Bureau of Census, printed January 16, 1991, in CenData Database, Dialog Information Services, April 5 and 8, 1991.

For tankers we have chosen an illustrative small entity threshold of 20,000 dead-weight tons DWT which encompasses 86 of the 266 tankers that transport the regulated products or 32.3 percent.

For barges we have chosen an illustrative threshold of 1,000 DWT which encompasses 1,069 of 1,609 or 66.4 percent of all barges that transport the regulated products.

The EPA RFA guidelines contain four criteria for determining significant economic impacts on small entities.

1. Product price increases;
2. Control cost differentials between small and larger plants;
3. Capital problems for small plants; and
4. Economic impacts such as closures.

The first step for determining significant impact was to calculate annual compliance costs of small entities as a percent of sales. Since price pass-through potentials have been calculated in this analysis, the RFA criteria is employed with price pass-through assumed. However, only average industry costs are assumed to be passed-through in the form of higher prices. In areas where limited competition exists, smaller terminals with higher than industry average cost increases, may be able to increase prices by a greater amount in the short run. Thus, the financial impact on the small facilities examined below may be overstated in the shortrun. In the long-run new terminals may be able to locate in areas that would suppress the ability to pass-on more than market average price increases.

For terminals the following calculations show the results of the step-one tests. A 500,000 barrel per year facility can experience compliance costs ranging from $0.46 per barrel (models 5C and 6C) to $1.23 per barrel (model 7A). Under RA A and RA B (the only alternatives containing a terminal of this size), Table 5-11 shows that the absorbed compliance costs for any combination of costs or RA's will always yield impacts greater than 40 percent of sales and thus are significantly impacted under Step one.

TABLE 5-11. SMALL ENTITY ANALYSIS

	Terminal throughput, barrels/yr										
	500,000				1,000,000			2,000,000			
Revenue/barrel, $	0.30				0.30			0.30			
After-tax profits/barrel	0.012				0.012			0.012			
Pretax, preprice increase terminal only compliance costs	0.46 (5C) 1.07 (6A) 0.46 (6C) 1.23 (7A)				0.23 (5C) 0.21 (6C) 0.62 (7A)			0.12 (5C) 0.27 (6A) 0.12 (6C) 0.31 (7A)			
Average costs per barrel per RA i.e., average price increase:											
RA A:	0.34				0.34			0.34			
RA B:	0.06				0.06			0.06			
RA C:	0.05				0.05			0.05			
RA D:	0.05				0.05			0.05			
RA E:	0.04				0.04			0.04			
Absorbed costs (average price increase/RA less terminal compl. costs per barrel)	5C	6	6C	7A	5C	6C	7A	5C	6	6C	7A
RA A:	0.12	0.73	0.12	0.89	(0.11)	(0.11)	0.26	(0.22)	(0.07)	(0.22)	(0.03)
RA B:	0.40	NA	NA	1.16	0.17	NA	0.56	0.06	NA	NA	0.25
RA C:	NA	NA	NA	NA	0.18	NA	0.57	0.07	NA	NA	NA
RA D:	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
RA E:	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Absorbed control costs ÷ sales, percent											
RA A:	40.0	100	40.0	> 100	Neg.	Neg.	93.3	Neg.	Neg.	Neg.	Neg.
RA B:	> 100	NA	NA	> 100	73.9	NA	> 100	16.7	NA	NA	83.3
RA C:	NA	NA	NA	NA	60.0	NA	> 100	3.3	NA	NA	86.7
RA D:	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
RA E:	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

A 1,000,000 barrel per year facility would be controlled under RA's A, B and C depending on the commodities loaded. Under RA's B and C the 1,000,000 barrel per year product facility will generally absorb control costs greater than 63 percent of sales. (Crude oil terminals of that size would not be affected).

The 2,000,000 barrel per year Model 7A gasoline terminal is also significantly impacted under RA B and C. The Model 5A 2,000,000 barrel per year facility is also significantly impacted under RA B.

The same data in Table 5-11 also shows that small plants control costs as a percent of sales are much higher than those of larger plants. For RA A, B and C control costs for larger plants are 20 to 30 percent of sales. The costs for small plants are typically 40 percent and more.

Thus the following analyses of crude oil and product terminal impacts focuses largely on small entity impacts since the price increase analysis and control cost differential analysis just performed above show potentially significant impacts. The analysis includes additional tests for small business impacts.

5.5.2.1 Crude Oil Terminals Impact Analysis. Most, if not all, crude oil loaded in this country is eventually purchased and processed by domestic petroleum refineries. Most petroleum refineries can purchase crude oil from multiple domestic sources or can import the crude oil.

Although the average control cost under RA A is $0.12 per barrel, the vast majority of the crude oil terminals would face control costs of more than $1.00 per barrel.

Table 5-11, shows that 500,000 barrel per year crude oil terminals controlled under RA A would not be able to pass forward all of its control costs in the form of price increases and would have to absorb costs amounting to 40.0 percent to over 100 percent of sales. The vast majority of small terminals only account for a modest percentage of total crude oil throughput at terminals. Most of these small terminals with high per barrel control costs will be by-passed by crude oil owners in favor of

other larger, lower cost terminals assuming the incremental costs to reach those substitute terminals is not prohibitive. The by-passed terminal owners will therefore be impacted by a loss of business. If crude oil owners did incur high terminal contract costs and if they did try to pass them on to refineries, the refineries would seek other crude oil suppliers, domestic or foreign. In theory terminal owners should be able to anticipate that they would be by-passed and would decide not to install the control systems at all.

The terminal business for crude oil handling of small amounts is a mixture of transshipments, periodic imbalances in location of supplies and deliveries from small oil fields. Facing high control costs under RA A, transshipments at small terminals will disappear in favor of alternative routes. Imbalances will be handled via other transportation modes. The owners of small oil fields will find other ways to get the oil to a refinery or will no longer pump the oil. Terminal owners could also not afford to absorb the control costs since the profits on even the highest loading costs of $0.50 per barrel would not permit an absorption of $0.12 per barrel.

The profit loss for a terminal owner earning 7.5 percent before taxes on the loading of 100,000 barrels of crude oil at a high level of $0.50 per barrel is $3,750.

For RA B and RA C the differentials are small enough that shifts of crude oil from terminal to terminal are not expected. Also under RA's D and E, no small crude oil terminals will be subject to control.

5.5.2.2 Product Terminal Impact Analysis. For reasons similar to the above it is expected that many product terminals covered by some of the RA's will be under competitive pressure when facing control costs in the high end of the range. These terminal owners may not be able to pass control costs onto product owners because the product owners can pay smaller incremental transportation costs to get product to a market. This assumes that substitute terminals are nearby or that new terminals with lower per unit control costs could be located to

serve as a substitute. In reality substitution is not perfect and even some small terminals with higher than average per unit control costs will be able to pass on those costs. Or, the cost to transport product to a nearby terminal exceeds the cost savings and the company may decide to absorb the costs. The quantitative analysis performed below assumes, as a starting point, that substitution is possible and therefore overstates the impact. Thus, some of the qualitative market factors will also be discussed.

The impact on terminals will be examined through a small entity impact analysis. What follows below is additional analysis which examines closure potential or other significant impacts. In this case closure potential means that a terminal owner would not purchase the control system and would therefore forego the business of loading the regulated products at the controlled quantity. However the terminal would still be able to remain in business to load and provide services for other products. In fact the terminal owner could even load regulated products as long as the quantities involved are less than the specified threshold of control. For example, under RA C, a terminal owner could load up to 999,999 barrels of gasoline per year without incurring a control requirement. Since these terminals may not be closure candidates they will be referred to as terminals under competitive pressure.

To analyze impacts by size of terminal, four financial ratios were selected to examine the before and after impact from the vapor control requirements. The ratios are: current assets to current liabilities (should exceed 1.0) long term debt to equity (should not exceed 1.5) cash flow to current maturities of long-term debt (should be 2.0 or greater), and earnings before interest and taxes (EBIT) divided by interest (should be 3.0 or greater).

The procedures used to calculate before and after ratios were to assemble the before ratios from Robert Morris Associates data for the Marine Cargo Handling Industry. Next an average cost per RA was determined. It was then assumed that the entity

could raise its prices by the RA's average cost and if the entity's per barrel cost was greater than the RA's average, the greater cost would have to be absorbed by the entity. The cost absorption would then begin to erode the financial ratios. If the ratios are eroded beyond the threshold criteria listed above then at risk potential exists.

Table 5-12 shows these calculations. The results show that for RA A, B, and C model facilities 5C and 7A incur high control per unit control costs. For RA D model facility 7A also has some competitive pressure. Model facility 7A appears to possess the greatest economies of scale since the minimum capital cost for any size terminal is $2.675 million excluding vessel retrofits. To illustrate this effect even the annualized costs for a 5,000,000 barrels per year terminal are $626,059 or $0.125 per barrel, compared to industry averages under RA's B-D of $0.05 to $0.06 per barrel.

TABLE 5-12. FINANCIAL ANALYSES OF SMALL PRODUCT TERMINALS

Throughput, barrels/yr	500,000	1,000,000	2,000,000	4,000,000
Revenue @ $0.40/bbl	150,000	300,000	600,000	1,200,000
Profits @ 4% AT	6,000	12,000	24,000	48,000
Depr @ 5%	7,500	15,000	30,000	60,000
Cash flow	13,500	27,000	54,000	108,000
Total assets (TA)	78,947	157,895	315,790	631,579
Current assets (CA) (43.4% of TA)	34,263	68,526	137,052	274,105
Current liabilities (CL) (71.4% of CA)	24,464	48,928	97,856	195,711
LT/debt (22.8% of TA)	18,000	36,000	72,000	144,000
Equity	36,483	72,966	145,932	291,860
Current matur. LT D	3,600	7,200	14,400	28,800
Interest	3,000	6,000	12,000	24,800
Ratios, precontrol			1.4	1.4
CA: CL	1.4	1.4	0.5	0.5
Debt: equity	0.5	0.5	1.75	3.75
Cash flow ÷ CMLTD	3.75	3.75	3.9	3.9
BBIT/interest	3.9	3.9		
Compliance costs	Annual	Annual	Annual	Annual
5C	228,782	232,643	239,658	250,000
7A	616,583	618,578	622,497	628,000
Compliance costs	Capital	Capital	Capital	Capital
5C	819,482	819,482	819,482	819,482
7A	2,675,508	2,675,508	2,675,508	2,675,508
Absorbed compliance costs				
RA A 5C	60,000	0	0	0
RA B 5C	200,000	170,000	120,000	50,000
Ratios (post-control) RA A 5C				
CA: CL	0.3	1.4	1.4	1.4
Debt: Equity	>20.1	0.5	0.5	0.5
Cash flow ÷ CMLTD	Neg.	3.75	3.75	1.75
EBIT/interest	Neg.	3.9	3.75	3.9
RA B 5C				
CA: CL	0.3	0.5	0.8	1.3
Debt: Equity	>20.1	11.8:1	6.0:1	1.0
Cash flow ÷ CMLTD	Neg.	<1	<1	1.3
EBIT/interest	Neg.	<1	<1	0.8

The number of terminals under competitive pressure is as follows:

Million barrels/yr, gasoline volume		No. of terminals		No. of terminals under competitive pressure		
		5C	7A	5C		7A[a]
0.5	RA B	29	46	29	+	36
1.0	RA C	6	34	6	+	24
5.0	RA D	0	15	0	+	5
10.0	RA E	0	6	0	+	0

[a]The calculations in Table 5-12 are not shown for Model 7A because the ratios for 5C show potential for competitive pressure and the costs for 7A are higher and will automatically also show competitive pressure.

The above analyses of terminal impacts indicates that a number of terminals are under competitive pressure with respect to the continuance of the business of loading the affected products; the size of the number depends on which RA is chosen. To the extent that this would happen, the actual nationwide control costs for each RA would substantially decrease for all regulated terminals. In effect the high per barrel control costs of small regulated terminals would be replaced by the low per barrel control costs of large terminals or by unregulated terminals.

Being under competitive pressure means that the terminal's control costs are significantly above the average for all regulated terminals. In a market with full competition from substitute terminals, such terminals face difficult choices of either trying to pass-on the higher costs, absorb the higher cost or discontinue loading controlled products. There are however, some factors which make this market less than fully competitive.

Most of the terminals in RA B thru RA E are most likely part of integrated petroleum refinery operations which on the surface can absorb the above average control costs. However, this

analysis treats those integrated facilities as being cost minimizers/profit maximizers and that they would consider abandoning their own terminal if another less cost terminal were accessible.

Nevertheless some integrated refineries are likely to choose to continue their terminal operations rather than be reliant on an independent company or another petroleum company. In remote areas the likelihood is that competition is also not perfect and that above average control costs may be absorbed. In more competitive areas, the extra cost to pump to a further terminal will sometimes be higher than the lower control cost of the accessible terminal. In addition, loading at another facility would either require a larger terminal than the one being replaced, which would require a cluster of producers to support the larger terminal, or may require multiple terminals with throughput less than the controlled amounts. The combination of these factors make the market for terminals less than perfect and serve to illustrate that the actual number of terminals under competitive pressure will be less than the quantities shown above.

Under RA D the estimate is that up to five terminals could be under competitive pressure. These terminals would most likely not be small. Under RA C the number jumps to 24 whereas under RA E the estimate is for no terminals under competitive pressure.

5.5.3 Marine Vessels

Vessels provide transportation of products from point A to point B. Movements can be from refinery to terminal, terminal to terminal (product can not be moved by large ship down shallow waters), and terminal to refinery (an imbalance of product). This is usually called transship which is when cargo is transferred from one vessel to another for reshipment.

The industry is highly competitive with 80 to 90 percent of the available vessels operating during 1989. There are 130 companies involved in this industry including both major oil companies and independent vessel owners. Business is much like a commodity where bids go in for every movement if it is not

covered by a long-term contract. Typically long-term contracts state a lower rate than spot movements, but if market conditions are such that many vessels are available, spot rates could be lower. Rates are highly dependent upon supply and demand.[3]

Construction of new barges and tankers are on the rebound. Almost all are being built with double hulls but usually not with manifolds for vapor recovery.[3] Typically, those vessels being built with manifolds are being done for the large vessel companies, for transporting benzene and for loading product in regulated States.

The aim of vessel companies is to maximize profit which means that vessels need to stay in operation as much as possible. Each movement that is not covered by a long-term contract will go out to bid much like a commodity product. Rate setting is a very competitive business, rates change continually.

There are two major groups of product - clean and dirty. The products considered clean are gasoline, naphtha, and diesel fuels. The products considered dirty are crude oil and fuel oil. Distillate fuel can be considered clean or dirty depending on whom is evaluating. Typically, a vessel that carries dirty products will be dedicated to dirty service. The reason is that to carry a clean product after carrying a dirty product means that the vessel needs to go through a vigorous and expensive cleaning procedure. The extent of this warrants or highly suggests dedicated service by a vessel owner to one type of product moved as opposed to moving both.

Another way to maximize profit for a commodity owner with vessels is to charter in and charter out. A commodity owner can charter in when more product needs to move than the number of vessels available to the owner. Charter out occurs when more vessels are available than there is product to move. Charter out is handled cautiously by vessel owners due to liability issues on spills and other accidental occurrences (see Section 5.7.2).

There are a number of different charter types: long-term contract, spot contract, MSC - military service charter, and Exxon charter. They tend to vary from a few hours to over

20 years. Long-term contracts are written for 1 year or more and are written specifically according to the needs of both parties. Spot contracts are used when product moves right away for a period of usually less than 6 months and written for one voyage only.

Rates for transportation are similar for all types of products. However, rates do vary according to the distance travelled, the size of vessel used, and market conditions of the region in which the vessel is moved. Rates are highly sensitive according to the region of the country where they occur because of the interplay between supply and demand. Rates can be stated in a long-term contract or in a spot contract. Domestic rates are quoted as an index published by the Association of Ship Brokers and Agents called the AR Scale. The book is published each year and contains a base AR for each product moved by a prototype ship of 27,800 dwt. International rates are quoted on the World Scale index.

Vessels carrying petroleum products are specialized because the Coast Guard certifies according to subchapter O and D, only those vessels appropriate for such movements. Of the U.S. flag vessels operating or available in 1989, 1,609 barges and 266 tankers were certified to carry subchapter O and D cargoes.

Barges move products and are typically unmanned except during loading and unloading when a Coast Guard certified tankerman is present. In addition, one person is needed for towing the non-propelled barge. Services provided by the barge owner include: cleaning of vessel according to product needs, amount of voyage time dictated by either spot or long-term contact, loading and unloading of product at dock (which can vary from 12 hours to 24 hours), and handling the maintenance requirements of the barge.

Furthermore if the barge is nonself-propelled, a tug is supplied. A barge towing service is used at or between points where the carrier does not have a tug available. Charges will be assessed according to hourly boat rates from where the tow

originates to the final destination and back to the original location of the tug.

Tankers move crude and have dedicated crews which are skilled to supervise loading and unloading. Services provided by the tanker owner include: cleaning of the tanker according to product needs, voyage time, loading and unloading time for product at dock, and handling the maintenance requirements of the tanker.

Because this industry is not regulated, rates are determined according to the market flow and are not required to be published or posted in any way. Rates are generally based on quality and service, amount of storage provided, length of time to load and unload, and the number of crew provided.

5.5.3.1 Tanker Impacts. The vapor control costs are not expected to cause tankers to loose business to pipelines or other modes of nonmarine transport. Thus the impact analysis must focus on what happens within the tanker industry. Domestic loading of petroleum products totaled 439 million short tons per year (1988). Presently tankers carry 51.7 percent of that total or 227 million short tons. The total amount of regulated products under each RA is presented in Table 5-13. Although the 51.7 percent share for tankers may be a good estimate under RA A, the percentage of regulated products carried by tankers increases as the RA's approach E. As shown in Table 5-13, a very large volume of crude oil (129.85 MM short tons) is handled by the three largest crude oil terminals and these terminals may need to install controls even under RA E.

Table 5-13 shows that not all of the tankers need to be retrofitted to accomodate the volume of controlled products. Therefore it is necessary to examine which types of vessels will retrofit, which will not, and the impacts on both categories.

The conclusion drawn herein is that enough tankers will be retrofitted under each RA to match the controlled volume, plus a reserve factor, and that those who do retrofit will be able to pass those control costs onto the producers. Owners of fleets of vessels will tend to retrofit those that are the least costly to

TABLE 5-13. PERCENTAGE OF TOTAL MARINE TRANSPORT OF PETROLEUM PRODUCTS AND CRUDE OIL AFFECTED BY THE REGULATORY ALTERNATIVES

	Throughput affected, millions of short tons		Percent of total marine transported petroleum	
	With	Without[a]	With	Without
RA A	410.6	280.8	93.5	64.0
RA B	237.2	107.3	54.0	24.4
RA C	225.0	95.1	51.3	21.7
RA D	167.5	37.6	38.2	8.6
RA E	153.8	23.9	35.0	5.4

[a]Without crude oil terminals with throughput >100MM bbl/yr .

retrofit. Those vessels that are not retrofitted will be dedicated to transporting uncontrolled products or controlled products from uncontrolled terminals. The impact of dedication on transporters is unknown with respect to profit rates on controlled and uncontrolled products. It is not known whether fleet owners who once transported controlled and uncontrolled products and who would only transport uncontrolled products will earn the same or less profits.

To determine which vessels will be retrofitted it is necessary to examine the retrofit costs and the distribution of tankers by age, size and the presence of single or double skins. For the combined capacity of tankers and barges, 93.5 percent of the 1988 volume of 439 million short tons would require retrofitted vessels. Under RA B that figure drops to 54 percent and 38 percent with RA D and 35 percent under RA E. These percentages drop sharply if the three large crude oil terminals are exempted. For example, under RA D only 8.6 percent of throughput would require retrofitted vessels. (These estimates exclude retrofitted capacity for transporting products controlled by State regulation or for transporting benzene).

Under RA A more than 94 percent of tanker capacity would have to be retrofitted to transport controlled products. This level of retrofit could be costly for some of the older or smaller tankers. Retrofit systems are estimated to have a useful life of 20 years. Exact useful lives of vessels are difficult to estimate but few vessels last past 50 years. This means that retrofits on vessels already older than 30 years are likely to last longer than the vessel. Or, in other words the cost would have to be recovered over a shorter period of time.

For RA B and RA C the 54 percent and 51 percent of capacity that requires retrofitting will consists to some extent of the already doubleskinned tankers which comprise 20.3 percent of all tankers. For RA D (38 percent) and RA E (35 percent) double-hull vessels would be the primary target of retrofits.

The model facilities that load crude oil or products into tankers are 6, 7A, and 7B. At these facilities the incremental

control cost per barrel for the vessel retrofit control costs (excluding terminal costs) is $0.002 for crude oil (6) and $0.019 and $0.026 for gasoline and chemical products (models 7A, 7B). These costs are constant over all sizes and ages of vessels. At a transport cost increase of $0.002 per barrel for crude oil and $0.0019 to $0.026 for products, it is not likely under any of the regulatory alternatives that there will be any significant adverse impact on the tankers.

However, there is some likelihood under each of the RA's that some of the smaller and the older tankers (>30 years) will not be retrofitted and would be cleaned and used to ship uncontrolled products. This type of impact can be described as one of efficiency where the retrofitted tankers would require special scheduling to be available when needed. Table 5-14 shows the age distribution of the U.S. tank ship fleet in 1989. Twenty-nine percent of tankers are older than 30 years. The older tankers also tend to be the smaller tankers. Twenty-nine of the 36 tankers over 40 years age are less than 10,000 dwt. Only one tanker over 30 years age is larger than 60,000 dwt.

Double-skinned tankers will most likely be retrofitted since they are also more insurable than single-skinned tankers. Fifty-four, or 20.3 percent of the tanker fleet is already double-skinned. Smaller tankers of less than 20,000 dwt comprise 32.3 percent of the fleet and are candidates for not being retrofitted.

Recent oil spill legislation (see Section 5.7.2) setting forth liability requirements for oil spills will act in concert with these regulations to affect single-skinned and older crude oil tankers. The cost to retrofit those tankers to prevent oil spills is likely to far exceed the cost impact of these regulations.

For gasoline and chemicals this increased transport cost for marine vessel retrofits is also likely to produce dedicated gasoline vessels as tankers older than 30 years would not be retrofitted.

TABLE 5-14. TANK SHIP FLEET BY AGE, 1989

Age	No.	Percent of fleet	Double skinned		Less than 20,000 DWT	
			No.	Percent	No.	Percent
0-10	49	18.4	18	36.7	12	24.5
11-20	107	40.2	34	31.8	20	18.7
21-30	33	12.4	1	3.0	11	33.3
31-40	41	15.4	1	2.4	14	34.1
>40	36	13.6	0	0.0	29	80.6
Total	266	100.0	54	20.3	86	32.3

Source: U.S. Coast Guard.

5.5.3.2 Barge Impacts. It is expected that certain percentages of the 1,609 barges currently in use will not be retrofitted under each RA because the volumes of regulated product fall short of the total barge capacity. The most likely barges to be retrofitted are ones that already have double-skins which amount to 57.9 percent of the barge fleet. This would represent substantially more than the percentage of products covered for RA B through RA E. The incremental control costs for retrofitted barges is $0.08 per barrel for crude oil and products for Cases 5A, 5B, 5C, 6BB, and 6BC. The incremental costs for products under model 7A are $0.019 per barrel and $0.0269 for 7B.

It is highly likely that barges older than 30 years and which transport products will not be retrofitted and would be assigned to carrying unregulated products such as asphalts, lube oils, and No. 6 oil or to carrying shipments from uncontrolled terminals. Table 5-15 shows the average age distribution of U.S. owned barges carrying subchapter O and D products in 1989. At a rate of 5.5 percent, barges older than 30 years amount to 89 of the 1,609 barges. The remaining barges plus new barges should be able to handle the necessary volume requirements for the transport routes for the regulated products under RA B thru E. Many of the older barges that will not be retrofitted are also typically smaller than the newer barges.

To the extent that the costs for retrofitting barges show a differential in favor of size, age or some other factor, those vessels favored by the bias will be retrofitted first.

5.5.4 Producers of the Regulated Products

Once the marine terminal and vessel owners pass some or all of their control costs onto the producers of the products, those producers will first consider raising the prices of the products in the market place. In this instance, the producers will first have to take into consideration the demand elasticity for each product. Demand elasticity will be sensitive to the fact that some products will reach markets without having been shipped by marine routes and will not have the VOC control costs in their price.

TABLE 5-15. U.S. BARGE FLEET BY AGE, 1989

Double skinned			Double skinned		Less than 1,000 DWT	
Age	No.	Percent of fleet	No.	Percent	No.	Percent
0-10	356	22.1	260	73.0	247	69.4
11-20	799	49.7	470	58.8	512	64.1
21-30	365	22.7	184	50.4	251	68.8
31-40	58	3.6	17	29.3	32	55.2
>40	31	1.9	0	0.0	27	87.1
Total	1,609	100.0	931	57.9	1069	66.4

Source: U.S. Coast Guard.

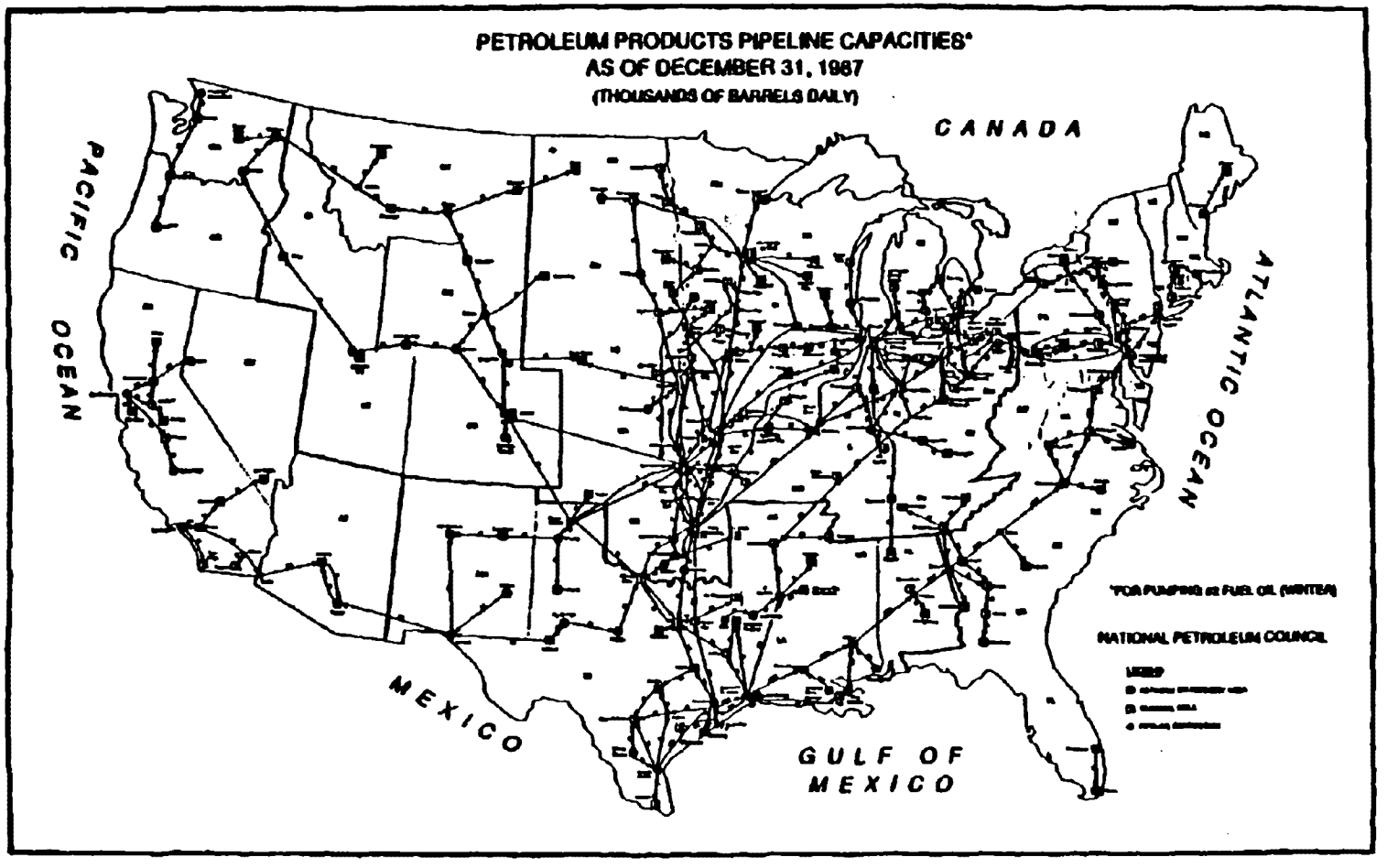
In order to determine the market price increase two pricing questions have to be answered:

1. How will refineries that load products into pipelines and onto marine vessels allocate the costs of VOC control?

2. Will refineries, wholesalers, and retailers be able to increase product prices if they compete with pipeline transported product?

With respect to the first question, petroleum refiners and petroleum-owned shipping companies have indicated that marine-loading costs are generally allocated to the refinery and marine vessel costs are allocated to the transportation costs of product. Further, the loading costs allocated to the refinery are treated as a generalized plant cost along with pipeline loading costs. (Most refineries can ship product by both pipeline and marine while also shipping to some nearby markets by truck). This would seem to suggest that the marine VOC control costs would increase the prices of all refined products exiting the refinery. However, when the refinery product pricers try to regain their margins that would otherwise be reduced by the increased loading costs they will realize that they can only increase prices in the markets where marine products are being shipped and not the markets where the pipeline products are being shipped. Thus the increased control costs end up being re-allocated to the marine transported products. The premise that this conclusion rests on is that the markets for the two sets of shipped products are distinct. This appears to be substantiated. Petroleum product geographic markets are for the largest part either served by pipelines or by vessels, as at least the initial bulk means of conveyance into areas. Of course where these markets touch there would be a mixture but for the most part the markets are separate. Thus when product prices are increased for the marine-loaded products the demand will be influenced in that market by traditional demand elasticity factors.

Figure 5-1 shows a map of pipeline locations in the United States. These are pipelines that ship petroleum products to markets. Notice that the pipelines are highly concentrated in



Source: National Petroleum Council. Petroleum Storage & Transportation. Vol. 5. Washington, DC April 1989, P.D-1.

Figure 5-1. Petroleum product pipeline capacities.

the mid-west, central southern, and middle atlantic States areas. The major marine shipments of petroleum products on the other hand are along the coastal waterways to coastal markets. The Mississippi system vessels carried over here. There are 300,000 tons of loaded petroleum products as compared to those coastal vessels which carried over 530,000 tons in 1988.[6]

To place the market reaction in perspective, Table 5-16 was constructed to accompany a product-by-product description.

Gasoline transported by marine faces a 1.01 percent price increase under RA A for the 14.54 percent portion of the entire U.S. market that will receive regulated gasoline which has been transported by marine. Demand for gasoline is generally regarded to be relatively inelastic. Even in the long term, it is difficult for motorists to reduce their dependence on gasoline. Many motorists, for example, are limited to their ability to purchase a more fuel-efficient motor vehicle or change their driving habits. Demand for motor gasoline is shaped by consumers' real disposable income, overall economic well being, and the price of gasoline. The Department of Energy has estimated that the long-term price elasticity of demand for gasoline is -0.55.[7]

The 14.54 percent of natural gasoline consumption affected by this regulation amounts to 16.274×10^9 gallons (see Table 5-16.) The long run reduction in output for gasoline is estimated at -0.55×1.01 percent $\times 16.274 \times 10^9$ gallons or 90.40×10^6 gallons. This equates to a 0.08 percent total output reduction based on the total consumption of 111.9×10^9 gallons shown in Table 5-16.

For RA B the output change for gasoline would only be 0.03 percent since the average price increase for gasoline is only 0.36 percent versus the 1.01 percent of RA A. The output changes for RA C thru RA E are even smaller.

Jet fuel and kerosene face a 1.66 percent price increase (RA A) for the 17.32 percent of total U.S. consumption that is transported by marine. Demand for jet fuel and kerosene reflects the number of air miles flown but has been influenced due to

TABLE 5-16. PORTIONS OF TOTAL MARKETS AFFECTED BY REGULATORY ALTERNATIVE A

Product	Percent price increase	Affected throughput, 000 gallons[a]	National consumption, 000 gallons[b]	1989 market percent affected
Gasoline	1.01	16,273,632	111,909,000	14.54
Jet fuel/kerosene	1.66	4,175,833	24,114,090	17.32
Naphtha	0.70	1,245,893	3,970,470	63.73
Distillate	1.20	19,324,624	49,056,000	39.39
Toluene	0.70	646,836	805,000	80.35
Methanol	1.82	1,990,766	5,292,000	37.62

NA = Not available.

[a]Source: Memorandum, Nicholson, R. and Kapella, D., Midwest Research Institute, to D. Markwordt, EPA, July 13, 1990, National Profile for the Development of a VOC Rule for Marine Vessel Loading Operations. Table 1.

[b]Source: U.S. Department of Energy, Energy Information Administration. Petroleum Supply Annual, 1989, p. xiixiii (for gasoline, jet fuel/kerosene, and distillate). Facts and Figures, C&E News June 18, 1990 p. 39 (for naphtha, toluene and methanol).

[c]Includes direct price increases plus passed-on crude oil control price increases.

improvements in aircraft efficiency, higher fuel prices, and an easing in passenger and freight travel. Higher airline ticket prices will also most likely contribute to a slower jet fuel demand growth. Demand for naphtha-type jet fuel, which is used principally for military purposes, is expected to remain near current levels through the year 2010. According to EPA estimates, demand elasticity for jet fuel is considered fairly inelastic perhaps less than that of gasoline at -0.30. At this level the reduced output under RA A would be 0.09 percent of total consumption (-0.30 x 1.66 percent x 17.32 percent of total consumption). These products would not be directly affected under the other RA's except for very small price increases (0.01 percent from crude oil control).

Distillate affected fuel oil faces a price increase of about 1.20 percent under RA A for the 39.39 percent of regulated U.S. consumption that is marine transported. Distillate fuel oil demand depends on the transportation and residential sectors. Distillate fuel oil is used in the transportation sector. Distillate fuel oil demand in the residential sector depends on conservation efforts, and competition from natural gas and electricity. According to EPA estimates, elasticity for distillate fuel oil is -0.5. At an assumed elasticity of -0.5 the reduction in output under RA A would be 0.24 percent (-0.5 x 1.20 percent x 39.39 percent). Distillate would not be controlled under the other RA's except for the 0.02 percent increase or less from crude oil control.

Naphtha faces price increases of 0.70 percent for the 63.7 percent of consumption that is marine transported. Demand for naphtha as a petrochemical feedstock is highly inelastic. According to EPA estimates, the demand for naphtha is not affected by income level and does not have close substitutes as a petroleum feedstock; therefore the elasticity of naphtha is estimated at -0.15. At a demand elasticity of -0.15 the output reduction is estimated at 0.07 percent (-0.15 x 0.70 percent x 63.7 percent). Again, naphtha is not directly affected under

the other RA's except for very small passed on crude oil control costs.

Toluene faces a 0.70 percent price increase under RA A which is not expected to cause reductions in output. Under RA B the estimated price increase is 0.41 percent. Toluene is an aromatic organic chemical primarily derived from petroleum refineries. Toluene and other aromatics are commonly used to increase the octane rating of unleaded gasoline. As a result, the market for toluene is closely related to the gasoline market. Recently, the demand for reformulated gasoline is pushing up toluene demand. Toluene is a good additive not only because it can be used as an octane enhancer, but also because it improves driveability and is a good method for reducing required vapor pressure. The expected increase in testing and marketing of reformulated gasoline will increase refiners' need for this aromatic and will most likely result in an increase in toluene demand over the long run.

The price increase for alcohols under RA A as represented by methanol is 1.80 percent. The percent of alcohols marine transported is 37.62. The assumed demand elasticity is -0.3. Therefore, the estimated output reduction under RA A is 0.20 (-0.3 x 1.80 percent x 37.62 percent). Under RA, B the estimated output change is 0.07 percent and 0.00 percent under RA D.

Demand for chemical products like ethylene glycol and methyl ethyl ketone are not expected to be significantly impacted. The price increase calculations show increases of less than one-half of 1 percent.

5.6 SMALL BUSINESS IMPACTS

For reasons explained earlier the SBA size definition of $12.5 million in sales was selected as being applicable in this analysis. Small business impacts utilizing the above specification, depend on the final decisions by EPA regarding the threshold level of terminal throughput controlled by the regulation. If all terminals are controlled under RA A then more than a thousand of the 1,749 terminal owners under competitive pressure may discontinue the business of loading crude oil or products. Many of these are small entities.

Under RA B thru RA E only the largest terminals in the industry are controlled; the totals being 104, 60, 25, and 13, compared to the 1749 terminals under RA A. The business from petroleum and crude oil products plus the other business from integrated operations most likely make these terminals large businesses (i.e., sales greater than $12.5 million). Therefore RA B thru RA E are not likely to involve a substantial (i.e., greater than 20 percent of affected terminals) number of small business impacts. This implies that a full Regulatory Flexibility Analysis need not be undertaken.

It should also be noted that under RA B thru RA E, the uncontrolled terminals (i.e., those that fall below the throughput cutoffs) may benefit from the regulation since they may obtain additional business if unregulated shipments increase at these terminals. In addition to the increased business, those terminals may also have some ability to raise prices unless new uncontrolled terminals enter the market.

Small vessel impacts are not expected to be significant because they will typically not be retrofitted under RA B thru RA E. Earlier we chose 1,000 Dwt as the definition of a small barge. On the basis of that definition, larger barges will be retrofitted before smaller barges. The volumes of product covered under RA B thru RA E will be manageable without small barges being retrofitted. Thus a full Regulatory Flexibility Analysis for them need not be undertaken.

5.7 EMPLOYMENT IMPACTS

According to the 1989 Bureau of Labor Statistics Employment and Earnings Report, 846,000 employees were involved in the petroleum industry, SIC 2911, SIC 5171 and SIC 5540.[8] As shown in Table 5-17, the potential change in employment at refineries as a result of output changes under RA A could total 807 workers (or 0.10 percent) due to this regulation. Under RA B about 165 workers could be affected. Under RA C, RA D, and RA E, 119, 38, and 38 workers would be affected.

Within the marine terminal sector there might be a shift of workers from the small controlled terminals to larger controlled

TABLE 5-17. POTENTIAL CHANGE IN EMPLOYMENT IN THE PETROLEUM REFINING INDUSTRY

Product	Employment estimate[a]	RA A		RA B		RA C		RA D		RA E	
		Output change, %	Potential change in employment	Output change, %	Potential change in employment	Output change, %	Potential change in employment	Output change, %	Potential change in employment	Output change, %	Potential change in employment
Gasoline	377,908	-0.08	303	-0.03	113	-0.02	76	-0.01	38	-0.01	38
Distillate	172,669	-0.24	415	-0.02	35	-0.02	35	0	0	0	0
Jet fuel/ kerosene	80,624	-0.09	73	-0.01	8	-0.01	8	0	0	0	0
Residual	57,528	NA	NA	0	0	0	0	0	0	0	0
Still gas	36,463	NA	NA	0	0	0	0	0	0	0	0
Coke	28,764	NA	NA	0	0	0	0	0	0	0	0
Feedstocks	23,011	-0.07	16	-0.04	9	0	0	0	0	0	0
Asphalt	24,957	NA	NA	0	0	0	0	0	0	0	0
LP gas	23,011	NA	NA	0	0	0	0	0	0	0	0
Lubricants	11,506	NA	NA	0	0	0	0	0	0	0	0
Miscellaneous	9,559	NA	NA	0	0	0	0	0	0	0	0
TOTAL	846,000		807		165		119		38		38

NA = Not available.

[a]Based on the product's yield from a barrel of crude oil.

terminals or to uncontrolled terminals. This follows a corresponding shift in business due to the impact of these regulations.

5.8 CONCURRENT LEGISLATION AND REGULATIONS

The economic impact analysis of any regulation is performed upon a baseline economic status in the regulated sector. The baseline economic status is a snapshot of the current economic condition of the sector. Naturally, economic baselines rarely remain static and are constantly being changed by new technological, political, social, and legislative events. All of these events have the potential of making the relative impact of VOC regulations appear greater or smaller. For example, as was shown above, if international events cause the price of crude oil to double as a a new baseline condition, then the potential price increase percentage is cut in half. Since a percentage calculation is relative, the impact appears to become smaller; although the absolute price increase per unit of output remains the same.

In this analysis it is important to present information on recent events that will have significant impacts on petroleum products and on marine vessels. These events are:

1. Budget Reconciliation Act of 1989 (PL101-239);
2. The Oil Pollution Act of 1990 (PL101-380);
3. The Clean Air Act Amendments of 1990 (PL101-549); and
4. Benzene handling regulations.

The nature of the impacts for the Oil Pollution Act (OPA) and the Clean Air Act Amendments (CAAA) are as yet unestimated. However, their impacts will intertwine with the impacts of VOC control.

5.8.1 Budget Reconciliation Act of 1989

Under this act Congress enacted a five-cent per barrel tax on oil that became effective January 1, 1990. This is equivalent to the control cost on a 10,000,000 barrel per year marine terminal handling crude oil. For the four U.S. terminals in Case 6 that handle crude oil at rates greater than 10,000,000 barrels per year, their volume handled is

443,830,189 barrels or 77.5 percent of the 572,457,028 barrels per year handled at all crude oil terminals in Cases 6, 6B, and 6C.

The perspective that this comparison provides is that the impact of this regulation for approximately 78 percent of crude oil loaded in the United States will be similar to the impact of the Budget Reconciliation Act.

5.8.2 The Oil Pollution Act of 1990

The Oil Pollution Act of 1990 (PL 101-380) was signed into law after the Senate and House of Representatives agreed on similar reform bills. The Act addresses double hulls, ship building capacity, spill liability, and related issues.

The package requires double hulls on all new oil tankers and barges operating in waters subject to U.S. jurisdiction. Existing vessels without double hulls need to be retrofitted or retire from service, according to a complex schedule based on vessel size and age; however, an outside date of 2015 applied in most cases. The legislation also contains a related provision which authorizes the Secretary of Transportation to provide loan guarantees under Title XII of the Merchant Marine Act of 1936 to help finance construction for double hulls.

Various exemptions and exceptions exist in the legislation. For example, oil response vessels are exempt from the double hull mandate. In addition, vessels unloading oil at deepwater ports and vessels engaged in lightering practices 60 miles or more offshore are exempt until 2015.

With regards to ship building capacity, new vessels of less than 5,000 gross tons, such as inland barges, must have some form of double containment system - though not necessarily double hulls. Existing vessels under 5,000 gross tons need to be retrofitted with double hulls or containment systems by 2015.

In addition, the act contains major liability and insurance provisions that require vessel owners to pay for oil spill cleanup costs and natural resource damages and to have liability insurance.

No economic impact assessments were performed by or for Congress and the appropriate committees in the process of passing the Oil Pollution Act of 1990. However, it has been assumed here that the following types of impacts are likely.

1. The cost of marine transport of crude oil will increase as a result of the liability requirements and the double hull construction requirements. These increases will occur simultaneously with the VOC control costs and together will raise the price of marine transport vis-a-vis pipeline transport costs.

2. Some older marine vessels will be made obsolete prematurely by the OPA of 1990 because of spill risk considerations. Some of these vessels will overlap with those that will become obsolesent prematurely due to the VOC vessel retrofit requirements. Thus the above estimates of marine vessel impacts are overstated by the unknown amount which is attributable to the OPA of 1990.

5.8.3 Clean Air Act Amendments of 1990

The price of gasoline and other VOC emitting petroleum and air toxic emitting chemicals will increase as a result of provisions of the CAAA. Tailpipe emission requirements in nonattainment areas, Reid Vapor Pressure (RVP) limitations, SOCMI air toxic emission controls and other provisions will all act to increase these product prices by unspecified amounts. On the other hand, incentives for reformulated and alternative fuels may in the long run cause gasoline prices to decrease. At this time it is quite speculative as to the magnitude and direction of these impacts.

5.8.4 Benzene NESHAP Handling Regulations

Some tankers and barges have already been retrofitted to collect fumes during benzene loading. To the extent that these vessels are also used to transport petroleum products, the cost of this regulation will decrease. It is unlikely that these vessels would carry crude oil.

5.9 FIFTH-YEAR PROJECTIONS

Nationwide control costs were estimated in this report on the basis of 1989 petroleum products throughput. Economic

impacts were estimated on the basis of 1990 and 1991 prices and market conditions. Expected conditions in the affected source category will be examined for fifth-year impacts in this section. This will be accomplished by obtaining estimates of demand changes and by examining any expected changes in production.

5.9.1 Crude Oil

The crude oil loading figures are directly associated with domestic production of crude oil. Domestic crude oil production is expected to drop from 7.6 million barrels per day in 1989 to 6.3 million barrels per day in 1995.[9] Meanwhile real prices are expected to rise from $18.07 in 1989 to $20.40 in 1995.[10]

5.9.2 Gasoline

Motor gasoline consumption is expected to increase from 7.33 million barrels per day in 1989 to 7.52 million barrels per day in 1995.[9] Gasoline prices are also expected to stay relatively flat.[10]

5.9.3 Other Products

Estimated projections for other products are as follows:

	Consumption, million barrels per day		Prices/gallon	
	1989	1995	1989	1995
Distillate	3.2	3.35	0.87	0.97
Jet fuel	1.49	1.63	0.59	0.71
Methanol	0.10	0.12 (1993)	0.55 (1990)	0.644 (1991)
Toluene	0.05	>0.05	1.42 (1990)	NA

Projections for methanol were only available to 1993 and no projections for toluene were readily available. However demand is expected to increase for reformulated gasolines that will find toluene to be an octane enhancer with the capability to lower reid vapor pressure.

5.9.4 Fifth-Year Demand Conclusions

In summary crude oil loadings will likely decrease while petroleum refinery loadings for the potentially regulated commodities will increase by amounts that are less than normal

economic growth rates. Thus fifth-year costs will be only slightly higher than the first-year control costs shown throughout this report.

5.9.5 Fifth-Year Supply Conditions

No supply restrictions or technological advances are expected among these products that would raise or lower product prices.

5.9.6 New Terminals and Vessels

The significant economies of scale for control costs will have the effect of favoring the construction of new large terminals versus small terminal for throughputs above the regulatory cutoff. The size of the capital control cost as a percent of the total cost of a terminal is also likely to affect the location of the control system to be nearer to the docks; perhaps giving a cost advantage to new terminals over retrofitted terminals. Exemptions from control for the smaller terminals may induce the construction of those size terminals.

Just as new double skin vessels have become commonplace, the vessel building industry will be able to manufacture new vessels with vapor collection systems already installed which may provide them with a cost advantage over retrofitted vessels.

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APPENDIX A.

MODEL VESSEL 1: Crude Oil Carrier (70,000 dwt)

Vessel characteristics:

Vessel dimensions, lxwxh:	800 ftx125 ftx55 ft
Draft, ft:	42
Cargo:	Crude oil
No. of cargo tanks:	15
Gauging and alarm system:	Yes, one system services all tanks
Normal loading rate, bbl/h:	35,000
Inert gas (IG) system:	Yes; boiler flue gas at 5 to 7 percent oxygen
Other:	2 pressure/vacuum (PV) valves on inert gas system are set at 2 psi, each sized for full flow; loading manifold is without header from IG system main.

Design assumptions:

1. Inert gas system and supply header will be used as the hydrocarbon vapor header; also, detonation arresters will be added.

2. An additional gauging and alarm system will be installed to provide redundant tank gauging capability.

MODEL VESSEL 2: Product Carrier (35,000 dwt)

Vessel characteristics:

Vessel dimensions, lxwxh:	700 ftx90 ftx50 ft
Draft, ft:	39
Cargo:	Motor and aviation gasoline; distillate diesel and jet fuels
No. of cargo tanks:	24
Gauging and alarm system:	No automatic system
Normal loading rate, bbl/h:	Up to 25,000
IG system:	None
Other:	Individual PV valves on each tank, set at 1.5 psi; loading manifold at midship.

Design assumptions:

1. Inert gas system and supply header will be used as the hydrocarbon vapor header; also, detonation arresters will be added.

2. Install a redundant tank gauging and alarm system.

MODEL VESSEL 3: Ocean Barge (19,000 dwt)

Vessel characteristics:

Vessel dimensions, lxwxh:	450 ftx75 ftx30 ft
Draft, ft:	24
Cargo:	Motor and aviation gasoline; distillate diesel and jet fuels
No. of cargo tanks:	12
Gauging and alarm system:	No automatic system
Normal loading rate, bbl/h:	Up to 15,000
IG system:	None
Other:	Individual PV valves on each tank, set at 1 psi; loading manifold at midship; diesel-driven pumps in the rear (aft) with no electric generator

Design assumptions:

1. Install complete vapor header.
2. Install redundant tank gauging and alarm system.

MODEL VESSEL 4: Inland River Barge

Vessel characteristics:

Vessel dimensions, lxwxh:	265 ftx54 ftx12 ft
Draft, ft:	9
Cargo:	Motor and aviation gasoline; distillate diesel and jet fuels
No. of cargo tanks:	10
Gauging and alarm system:	No automatic system
Normal loading rate, bbl/h:	4,000
IG system:	None
Other:	Individual PV valves on each tank set at 1 psi; loading manifold in the rear; diesel driven cargo pump (in the rear), with no electric generator

Design assumptions:

1. Install a complete vapor header.
2. Install redundant tank gauging and alarm system.

MODEL 5A: Product Terminal for Barges

Terminal characteristics

- Two docks, designed to load two barges at each side from two loading stations at each dock
- Loading rate of 4,000 bbl/h per barge
- Maximum loading rate of 16,000 bbl/h
- Inert gas generator located 200 feet away
- All gasoline storage tanks have floating roofs
- Transfer pumps located 300 yards from dock
- Loadings handled by one person at waterfront and one at tank farm
- Annual throughput of greater than 8 million bbl/yr

Design assumptions:

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install four complete vapor transfer lines and associated incinerator feed headers
- Install two full-capacity booster fans arranged in parallel
- Install terminal alarm system and vapor control system instruments

MODEL 5B: Product Terminal for Barges

Terminal characteristics:

- One dock, designed to load one barge at each side from two loading stations
- Loading rate of 4,000 bbl/h per barge
- Maximum loading rate of 8,000 bbl/h
- Incinerator located 1/4 mile away
- Inert gas generator located 200 feet away
- All gasoline storage tanks have floating roofs
- Transfer pumps located 300 yards from dock
- Loadings handled by one person at waterfront and one at tank farm
- Annual throughput of greater than 4 million bbl/yr and less than 8 million bbl/yr

Design assumptions:

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install two complete vapor transfer lines and associated incinerator feed headers.
- Install two full-capacity booster fans arranged in parallel
- Install terminal alarm system and vapor control system instruments

MODEL 5C: Product Terminal for Barges

- One dock, designed to load one barge from one loading station
- Loading rate of 4,000 bbl/h per barge
- Maximum loading rate of 4,000 bbl/h
- Incinerator located 1/4 mile away
- Inert gas generator located 200 feet away
- All gasoline storage tanks have floating roofs
- Transfer pumps located 300 yards from dock
- Loadings handled by one person at waterfront and one at tank farm
- Annual throughput of greater than 4 million bbl/yr

Design assumptions

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install one complete vapor transfer line and associated incinerator feed headers
- Install two full-capacity booster fans arranged in parallel
- Install terminal alarm system and vapor control system instruments

MODEL 6A: Crude Oil Terminal for Ships

Terminal characteristics:

- One dock, designed to load one ship of up to 75,000 dwt at a time
- Loading rate of 35,000 bbl/h (loads only one type of crude oil)
- Incinerator located 1 mile from dock
- 220-volt AC electricity available at tank farm (located 1 mile away)
- Natural gas service located 6 miles away
- Storage tanks have floating roofs
- Terminal operated by one person at tank farm and one at the dock
- Minimal 110-volt AC electric power available at dock

Design assumptions:

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency - 98 percent
- Install one complete hydrocarbon vapor transfer line and incinerator feed header
- Vessels have own inert gas systems; therefore, inert gas generator is not necessary
- Incinerator located 1 mile from dock area
- Natural gas service available 6 miles from incinerator

MODEL 6B: Crude Oil Terminal for Barges

Terminal characteristics:

- One dock, designed to load one barge at each side from two loading stations
- Loading rate of 4,000 bbl/h per barge
- Maximum loading rate of 8,000 bbl/h
- Incinerator located 1/4 mile away
- Inert gas generator located 200 feet away
- All crude oil storage tanks have floating roofs
- Transfer pumps located 300 yards from dock
- Loadings handled by one person at waterfront and one at tank farm
- Annual throughput of greater than 4 million bbl/yr and less than 8 million bbl/yr

Design assumptions:

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install two complete vapor transfer lines and associated incinerator feed headers.
- Install two full-capacity booster fans arranged in parallel
- Install terminal alarm system and vapor control system instruments

MODEL 6C: Crude Oil Terminal for Barges

- One dock, designed to load one barge from one loading station
- Loading rate of 4,000 bbl/h per barge
- Maximum loading rate of 4,000 bbl/h
- Incinerator located 1/4 mile away
- Inert gas generator located 200 feet away
- All crude oil storage tanks have floating roofs
- Transfer pumps located 300 yards from dock
- Loadings handled by one person at waterfront and one at tank farm
- Annual throughput of greater than 4 million bbl/yr

Design assumptions

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install one complete vapor transfer line and associated incinerator feed headers
- Install two full-capacity booster fans arranged in parallel
- Install terminal alarm system and vapor control system instruments

MODEL 7A: Product Terminal Serving Ships and Barges

Terminal characteristics

- One pier for loading one ship of up to 35,000 dwt
- One dock for loading one inland barge
- Tankship loading station can supply 25,000 bbl/h
- Barge loading station can load 4,000 bbl/h
- Maximum loading rate of 29,000 bbl/h
- Incinerator located 1 mile away
- Inert gas generator located 200 feet away
- 220-volt AC electricity and natural gas service available 100 yards from potential incinerator location
- All gasoline storage tanks have floating roofs
- Terminal operated by one person at each dock or pier and two at the tank farm
- Annual throughput of less than 29 million bbl/yr

Design assumptions:

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install one complete barge hydrocarbon vapor transfer line
- Install one complete ship hydrocarbon vapor transfer line
- Natural gas available 900 ft from incinerator
- Install terminal alarm system and vapor control system instruments
- Install two parallel sets of full capacity boosters for incinerator feed to dock area

MODEL 7B: Product Terminal Serving Ships and Barges

- One pier for loading two ships of up to 35,000 dwt
- Two docks for loading four inland barges at each dock
- Two tankship loading stations can supply 25,000 bbl/h each
- Four barge loading stations can load 4,000 bbl/h each
- Maximum loading rate of 66,000 bbl/h
- Incinerator located 1 mile away
- Inert gas generator located 200 feet away
- 220-volt AC electricity and natural gas service available 100 yards from potential incinerator location
- All gasoline storage tanks have floating roofs
- Terminal operated by one person at each dock or pier and two at the tank farm
- Annual throughput of greater than 29 million bbl/yr

Design assumptions:

- Hydrocarbon vapors destroyed via incineration
- Incinerator destruction efficiency = 98 percent
- Install four complete barge hydrocarbon vapor transfer lines
- Install two complete ship hydrocarbon vapor transfer lines
- Natural gas available 900 ft from incinerator
- Install terminal alarm system and vapor control system instruments
- Install two parallel sets of full capacity boosters for incinerator feed to dock area

APPENDIX B.

Documentation of Costs for an Incineration-Based Technology

Cost Methodology Documentation (Model 5A)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 5A

Incinerator capital cost	
(220,400 + [11.57 x 3,550 scfm]) x 323.8/342.5 =	247,197
Installation	81,575
Total installed cost (rounded)	329,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices.[5,6,9] An additional 20 percent was added for installation.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	79,900
	(automatic flow control)	4,110
Total:		84,010

Model 5A IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model 5A this maximum loading rate is 16,000 bbl/hr (4 barges @ 4,000 bbl/hr/barge).

VOC gas stream flow is calculated as:

16,000 bbl/hr x 5.615 ft^3/bbl = 89,840 ft^3/hr

Inert gas required is calculated as:

89,840 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 123,080 ft^3/hr IG

Model 5A IG cost: $84,010(123,080/60,000)^{0.7} \times (323.8/322.7) \times 1.2 = 167,270$

Model 5A IG cost (rounded): 167,000

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 5A	
Assume 6 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 123,000 ft^3/min	~1,000 gal/min
Average velocity	11.71 ft/sec
Reynolds No.:	595
Fricton factor:	0.1
Pressure drop	43 psi
Pump cost = $6,000 x 1.4 x (323.8/355.4)	7,653
Pipe cost = $1,200/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	8,188
Total	15,841
Total (rounded)	15,800

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 5A

Incinerator booster fan		25,000
Incinerator detonation arrestor		34,960
Incinerator trip valve		10,680
3-way inert gas valve		6,500
Eductors	4 x 6,250 =	25,000
Detonation arrestors	4 x 24,076 =	96,304
Barge hydrocarbon vapor headers	4 x 5,280 =	21,120
Back pressure valves	4 x 5,280 =	21,120
Total Other Major Equipment		240,684

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 5A -	IG generator to dock	200 ft (constant)
	Dock to incinerator	660 ft to 1,400 ft

Example:

Model 5A - low piping cost

IG eductor feed	4 x 1,311 =	5,244
IG water line		1,311
Hydrocarbon vapor feed	4 x 1,346.5 =	5,386
Eductor discharge	4 x 2,683 =	10,732
IG feed header		36,456
Natural gas to incinerator		54,120
IG generator to dock	51.045 x (200 ft/1,400 ft) =	7,292
Dock to incinerator	107,051 x (660 ft/1,400 ft) =	50,467
Total piping cost		171,088
Total piping cost (rounded)		171,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 5. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 5A

Explosionproof alarm		16,800
Vapor line oxygen probe		5,880
Barge header oxygen probes	4 x 5,880 =	23,520
Pressure - vaccum sensors	4 x 900 =	3,600
Total instrumentation		49,800

G. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering	=	10 percent
Startup	=	10 percent
Contingencies	=	5 percent
		25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 5A

Throughput	=	2,000 hr/yr x 8,000 bbl/hr = 16,000,000 bbl/yr
Number vessels	=	16,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
	=	43.84 vessels
TCI	=	$168,000/vessel x 43.84 vessels = 7,365,120
TCI (rounded)	=	7,360,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[4] Assumed 2,000 operating hours per year.[5]

Example:

Model 5A

2,000 hr/yr|8 hr/shift = 250 shifts/yr	
250 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$1,863/yr
For operating both incinerator and IG generator	x 2
From 1988 dollars to 1987 dollars	x (323.8/342.5)
	$3,523/yr
Labor (rounded)	$3,520/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by 2 to compensate for the inert gas generator. This number is again multiplied by 2 to compensate for parts.

Example:

Model 5A

$40,800/yr	From UTD, annual preventive maintenance costs	
- 8,000/yr	Incinerator scrubber maintenance	
$32,800/yr		
Maintenance parts and labor		
250 shifts/yr x 0.5 hr/shift x $14.26/hr		$1,782/yr
For maintaining both incinerator and IG generator		x 2
For parts		x 2
From 1989 dollars to 1987 dollars		(323.8/342.5
		$6,741/yr

Total maintenance = $32,800 + $6,741 = $39,541/yr
Total maintenance (rounded) = $39,500/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr = size (ft^3/hr)/8.6 ft^3

Example

Model 5A

Percent of operating capacity = 8,000 bbl/hr|16,000 bbl/hr =	0.5
IG fuel = 123,080 ft^3/hr|8.6 x 2,000 hr/yr x $3.43/1,000 ft^3 x 0.5 =	49,090
Incinerator pilot light =	7,650
Total natural gas cost =	56,740
Total natural gas =	56,700

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage agreed for model 5. Electricity costs for incinerator feed fans was taken from the UTD estimate for model 5A and adjusted to a rate of $0.0472/kWh.[2,8]

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Model 5A

Electrical costs

$$\left[\frac{\$3,000}{\$0.08/kWh} + \left(\left\{\frac{123,080\ ft^3/hr \times 455}{508,600} - 16\right\} \times 2,000\ hr/yr\right)\right] \times \$0.0472/kWh \times 0.5 = \$5,327/yr$$

Electrical costs (rounded) = $5,330/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 5A (low end)

CRC = [171,008 x 0.1175] + [(1,216,695 - 171,018) x 0.1627] = $190,267
CRC (rounded) = $190,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3.

Model 5A

Capital recovery	$19,750/vessel x 43.84 vessels =	$866,000
Maintenance	$9,600/vessel x 43.84 vessels =	420,000
Vessel retrofit TAC =		1,286,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 5A (gasoline)

(3.4/1,000 gal) x (16,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb) x 0.98 = 1,014 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 5A (terminal only)

$$\frac{369,900\ (\$/yr)}{1,014\ (Mg/yr)} = 365\ (\$/Mg)$$

Model 5A (terminal and ships)

$$\frac{1,655,739\ (\$/yr)}{1,014\ (Mg/yr)} = 1,632\ (\$/Mg)$$

Cost Methodology Documentation (Model 5B)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 5B

Incinerator capital cost	
(220,400 + [11.57 x 3,550 scfm]) x 323.8/342.5 =	227,782
Installation	75,168
Total installed cost (rounded)	303,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices.[5,6,9] An additional 20 percent was added for installation.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	
	(automatic flow control)	79,900
Total:		84,010

Model 5B IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model 5B this maximum loading rate is 8,000 bbl/hr (2 barges @ 4,000 bbl/hr/barge).

VOC gas stream flow is calculated as:

8,000 bbl/hr x 5.615 ft^3/bbl = 44,920 ft^3/hr

Inert gas required is calculated as:

44,920 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 61,540 ft^3/hr IG

Model 5B IG cost: $84,010(61,546/60,000)^{0.7} \times (323.8/322.7) \times 1.2 = 102,967$

Model 5B IG cost (rounded): 103,000

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 5B	
Assume 6 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 123,000 ft^3/min (oversized)	~1,000 gal/min
Average velocity	11.71 ft/sec
Reynolds No.:	595
Fricton factor:	0.1
Pressure drop	43 psi
Pump cost = $6,000 x 1.4 x (323.8/355.4)	7,653
Pipe cost = $1,200/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	8,188
Total	15,841
Total (rounded)	15,800

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 5B

Incinerator booster fan		25,000
Incinerator detonation arrestor		34,960
Incinerator trip valve		10,680
3-way inert gas valve		6,500
Eductors	2 x 6,250 =	12,500
Detonation arrestors	2 x 24,076 =	48,152
Barge hydrocarbon vapor headers	2 x 5,280 =	10,560
Back pressure valves	2 x 5,280 =	10,560
Total Other Major Equipment		158,912

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 5B -	IG generator to dock	200 ft (constant)
	Dock to incinerator	660 ft to 1,400 ft

Example:

Model 5B - low piping cost

IG eductor feed	2 x 1,311 =	2,622
IG water line		1,311
Hydrocarbon vapor feed	2 x 1,346.5 =	2,693
Eductor discharge	2 x 2,683 =	5,366
IG feed header		36,456
Natural gas to incinerator		54,120
IG generator to dock	$26.93/ft x 200 ft	5,386
Dock to incinerator	$52.55/ft x 660 ft	34,683
Total piping cost		142,637
Total piping cost (rounded)		143,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 5. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 5B

Explosionproof alarm		16,800
Vapor line oxygen probe		5,880
Barge header oxygen probes	2 x 5,880 =	11,760
Pressure - vaccum sensors	2 x 900 =	1,800
Total instrumentation		36,240

G. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering =	10 percent
Startup =	10 percent
Contingencies =	5 percent
	25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 5B

Throughput =	2,000 hr/yr x 4,000 bbl/hr = 8,000,000 bbl/yr
Number vessels =	8,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
=	21.92 vessels
TCI =	$168,000/vessel x 21.92 vessels = 3,682,000
TCI (rounded) =	3,682,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[5] Assumed 2,000 operating hours per year.[5]

Example:

Model 5B

2,000 hr/yr|8 hr/shift = 250 shifts/yr	
250 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$1,863/yr
For operating both incinerator and IG generator	x 2
From 1988 dollars to 1987 dollars	x (323.8/342.5)
	$3,523/yr
Labor (rounded)	$3,520/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by 2 to compensate for the inert gas generator. This number is again multiplied by 2 to compensate for parts.

Example:

Model 5B

$40,800/yr	From UTD, annual preventive maintenance costs	
- 8,000/yr	Incinerator scrubber maintenance	
$32,800/yr		
Maintenance parts and labor		$1,782/yr
For maintaining both incinerator and IG generator		x 2
For parts		x 2
From 1989 dollars to 1987 dollars		(323.8/342.5
		$6,741/yr

Total maintenance = $32,800 + $6,741 = $39,541/yr
Total maintenance (rounded) = $39,500/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr) = size (ft^3/hr)/8.6 ft^3

Example

Model 5B

Percent of operating capacity = 8,000 bbl/hr|16,000 bbl/hr =	0.5
IG fuel = 61,540 ft^3/hr|8.6 x 2,000 hr/yr x $3.43/1,000 ft^3 x 0.5 =	24,545
Incinerator pilot light =	7,650
Total natural gas cost =	32,195
Total natural gas cost (rounded) =	32,200

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] Electricity costs for incinerator feed fans were taken from the UTD estimate for model 5B and adjusted to a rate of $0.0472/kWh.[2,8]

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Model 5B

Electrical costs=

$$\left[\frac{\$3,000}{\$0.08/kWh} + \left(\left\{\frac{61,540\ ft^3/hr \times 455}{508,600} - 16\right\} \times 2,000\ hr/yr\right)\right] \times \$0.0472/kWh \times 0.5 = \$2,728/yr$$

Electrical costs (rounded) = $2,730/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 5B (low end)

CRC = [142,637 x 0.1175] + [(932,722 - 142,637) x 0.1627] = $148,055
CRC (rounded) = $148,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3.

Model 5B

Capital recovery=	$19,750/vessel x 21.92 vessels =	$433,000
Maintenance=	$9,600/vessel x 21.92 vessels =	210,000
Vessel retrofit TAC =		643,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 5B (gasoline)

(3.4/1,000 gal) x (16,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb) x 0.98 = 507 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 5B (terminal only)

$$\frac{289,853\ (\$/yr)}{507\ (Mg/yr)} = 572\ (\$/Mg)$$

Model 5B (terminal and ships)

$$\frac{932,772\ (\$/yr)}{507\ (Mg/yr)} = 1,839\ (\$/Mg)$$

Cost Methodology Documentation (Model 5C)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 5C

Incinerator capital cost	
(220,400 + [11.57 x 887.5 scfm]) x 323.8/342.5 =	218.074
Installation	71,964
Total installed cost (rounded)	290,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices by EPA methodology.[5,6,9] An additional 20 percent was added for installation.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	79,900
	(automatic flow control)	4,110
Total:		84,010

Model 5C IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model 5C this maximum loading rate is 4,000 bbl/hr (1 barge @ 4,000 bbl/hr/barge).

VOC gas stream flow is calculated as:

4,000 bbl/hr x 5.615 ft^3/bbl = 22,460 ft^3/hr

Inert gas required is calculated as:

22,460 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 30,770 ft^3/hr IG

Model 5C IG cost: $84,010(30,770/60,000)^{0.7} \times (323.8/322.7) \times 1.2 = 63,383$

Model 5C IG cost (rounded): 63,400

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 5C	
Assume 6 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 123,000 ft^3/min (oversized)	-1,000 gal/min
Average velocity	11.71 ft/sec
Reynolds No.:	595
Fricton factor:	0.1
Pressure drop	43 psi
Pump cost = $6,000 x 1.4 x (323.8/355.4)	7,653
Pipe cost = $1,200/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	8,188
Total	15,841
Total (rounded)	15,800

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 5C

Incinerator booster fan		25,000
Incinerator detonation arrestor		34,960
Incinerator trip valve		10,680
3-way inert gas valve		6,500
Eductors	1 x 6,250 =	6,250
Detonation arrestors	1 x 24,076 =	24,076
Barge hydrocarbon vapor headers	1 x 5,280 =	5,280
Back pressure valves	1 x 5,280 =	5,280
Total Other Major Equipment		118,026

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 5C - IG generator to dock200 ft (constant)
Dock to incinerator 660 ft to 1,400 ft

Example:

Model 5C - low piping cost

IG eductor feed		1,311
IG water line		1,311
Hydrocarbon vapor feed		1,346.5
Eductor discharge		2,683
IG feed header		36,456
Natural gas to incinerator		54,120
IG generator to dock	$19.56/ft x 200 ft	3,912
Dock to incinerator	$26.93/ft x 660 ft	17,774
Total piping cost		118,913
Total piping cost (rounded)		119,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 5. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 5C

Explosionproof alarm		16,800
Vapor line oxygen probe		5,880
Barge header oxygen probes	1 x 5,880 =	5,880
Pressure - vaccum sensors	1 x 900 =	900
Total instrumentation		29,460

G. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering	=	10 percent
Startup	=	10 percent
Contingencies	=	5 percent
		25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 5C

Throughput	=	1,000 hr/yr x 4,000 bbl/hr = 4,000,000 bbl/yr
Number vessels	=	4,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
	=	10.96 vessels
TCI	=	$168,000/vessel x 43.84 vessels = 1,841,000
TCI (rounded)	=	1,840,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[4] Assumed 1,000 operating hours per year.[5]

Example:

Model 5C

1,000 hr/yr|8 hr/shift = 125 shifts/yr	
125 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$932/yr
For operating both incinerator and IG generator	x 2
From 1989 dollars to 1987 dollars	x (323.8/342.5)
	$1,761/yr
Labor (rounded)	$1,761/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by 2 to compensate for the inert gas generator. This number is again multiplied by 2 to compensate for parts.

Example:

Model 5C

$40,800/yr	From UTD, annual preventive maintenance costs	
- 8,000/yr	Incinerator scrubber maintenance	
$32,800/yr		
Maintenance parts and labor		
125 shifts/yr x 0.5 hr/shift x $14.26 hr		$891/yr
For maintaining both incinerator and IG generator		x 2
For parts		x 2
From 1989 dollars to 1987 dollars		(323.8/342.5
		$3,369/yr

Total maintenance = $32,800 + $3,369 = $36,169/yr
Total maintenance (rounded) = $39,200/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr = size (ft^3/hr)/8.6 ft^3

Example

Model 5C

Percent of operating capacity = 4,000 bbl/hr|4,000 bbl/hr =	1.0
IG fuel = 30,770 ft^3/hr|8.6 x 1,000 hr/yr x $3.43/1,000 ft^3 x 1.0 =	12,272
Incinerator pilot light =	7,650
Total natural gas cost =	19,922
Total natural gas cost (rounded) =	19,900

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage agreed for model 5. Electricity costs for incinerator feed fans was taken from the UTD estimate for models 5 and 6 and adjusted to a rate of $0.0472/kWh.[2,8]

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Model 5C

Electrical costs

$$\left[\frac{\$3{,}000}{\$0.08/kWh} + \left(\left\{\frac{30{,}770\ ft^3/hr \times 455}{508{,}600} - 16\right\} \times 2{,}000\ hr/yr\right)\right] \times \$0.0472/kWh \times 1.0 = \$2{,}314$$

Electrical costs (rounded) = $2,300/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 5C (low end)

CRC = [118,026 x 0.1175] + [(794,572 - 118,026) x 0.1627] = $123,928
CRC (rounded) = $124,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3.

Model 5C

Capital recovery	$19,700/vessel x 10.96 vessels =	$216,000
Maintenance	$9,600/vessel x 10.96 vessels =	105,000
Vessel retrofit TAC =		321,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 5C (gasoline)

(3.4/1,000 gal) x (4,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb) x 0.98 = 254 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 5C (terminal only)

$$\frac{238,636\ (\$/yr)}{254\ (Mg/yr)} = 941\ (\$/Mg)$$

Model 5C (terminal and ships)

$$\frac{560,096\ (\$/yr)}{254\ (Mg/yr)} = 2,209\ (\$/Mg)$$

Cost Methodology Documentation (Model 6A)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 6A

Incinerator capital cost	
(220,400 + [11.57 x 3,275 scfm]) x 323.8/342.5 =	244,189
Installation	80,582
Total installed cost (rounded)	325,000

B. Other Major Equipment

The capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.

Example:

Model 6A

Other major equipment	152,000

C. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 6A - low piping cost

Natural gas to incinerator	1,105,949 x (2,640 ft/31,680 ft) =	92,162
Dock to incinerator	445,650 x (660 ft/6,000 ft) =	49,022
Total piping cost		141,184
Total piping cost (rounded)		141,000

D. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate.

Example:

Model 6A

Total instrumentation	33,700

E. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies - per the UTD cost estimate, engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[1]

Engineering =	10 percent
Startup =	10 percent
Contingencies =	5 percent
	25 percent

F. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 6A

Throughput =	2,000 hr/yr x 35,000 bbl/hr = 70,000,000 bbl/yr
Number vessels =	70,000,000 bbl/yr|365 d/yr|25,000 bbl/vessel/d
=	7.67 vessels
TCI =	$168,000/vessel x 7.67 vessels = 1,288,767
TCI (rounded) =	1,290,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[5] Assumed 2,000 operating hours per year.[2]

Example:

Model 6A

2,000 hr/yr|8 hr/shift = 250 shifts/yr	
250 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$1,863/yr
From 1989 dollars to 1987 dollars	x (323.8/342.5)
$1,761/yr	
Labor (rounded)	$1,760/yr

B. Maintenance

The costs of maintenance are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by two to compensate for parts.

Example:

Model 6A

$28,000/yr From UTD, annual preventive maintenance costs	
Maintenance parts and labor	
250 shifts/yr x 0.5 hr/shift x $14.26/hr	$1,782/yr
For parts	x 2
From 1989 dollars to 1987 dollars	(323.8/342.5
	$3,369/yr

Total maintenance = $28,800 + $3,369 = $31,369/yr
Total maintenance (rounded) = $31,400/yr

C. Natural Gas

The natural gas costs are from the UTD estimate and include the incinerator pilot light only.[2]

Example

Model 6A

Incinerator pilot light = 7,650

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage agreed for model 6A.

Example:

Model 6A

Electrical costs

$$\frac{\$3,000}{\$0.08/kWh}\ \$0.0472/kWh = \$1,770/yr$$

Electrical costs (rounded) = $1,770/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 6A (low end)

CRC = [141,184 x 0.1175] + [815,049 - 141,184) x 0.1627] = $126,252
CRC (rounded) = $125,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3.

Model 6A

Capital recovery =	$19,700/vessel x 7.67 vessels =	$151,000
Maintenance =	$4,800/vessel x 7.67 vessels =	36,800
Vessel retrofit TAC (rounded) =		188,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 6A (crude oil)

(0.61 lb/1,000 gal) x (70,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 (Mg/lb) x 0.98 = 796 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 6A (terminal only)

$$\frac{221,283\ (\$/yr)}{796\ (Mg/yr)} = 278\ (\$/Mg)$$

Model 6A (terminal and ships)

$$\frac{409,483\ (\$/yr)}{796\ (Mg/yr)} = 514\ (\$/Mg)$$

Cost Methodology Documentation (Model 6B)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 6B

Incinerator capital cost	
(220,400 + [11.57 x 1,775 scfm]) x 323.8/342.5 =	227,782
Installation	75,168
Total installed cost (rounded)	303,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices.[5,6,9] An additional 20 percent was added for installation.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	
	(automatic flow control)	79,900
Total:		84,010

Model 6B IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model 6B this maximum loading rate is 8,000 bbl/hr (2 barges @ 4,000 bbl/hr/barge).

VOC gas stream flow is calculated as:

8,000 bbl/hr x 5.615 ft^3/bbl = 44,920 ft^3/hr

Inert gas required is calculated as:

44,920 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 61,540 ft^3/hr IG

Model 5B IG cost: $84,010(61,546/60,000)^{0.7} \times (323.8/322.7) \times 1.2 = 102,967$

Model 5B IG cost (rounded): 103,000

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 6B

Assume 6 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 123,000 ft^3/min	~1,000 gal/min
Average velocity	11.71 ft/sec
Reynolds No.:	595
Fricton factor:	0.1
Pressure drop	43 psi
Pump cost = $6,000 x 1.4 x (323.8/355.4)	7,653
Pipe cost = $1,200/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	8,188
Total	15,841
Total (rounded)	15,800

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 6B

Incinerator booster fan		25,000
Incinerator detonation arrestor		34,960
Incinerator trip valve		10,680
3-way inert gas valve		6,500
Eductors	2 x 6,250 =	12,500
Detonation arrestors	2 x 24,076 =	48,152
Barge hydrocarbon vapor headers	2 x 5,280 =	10,560
Back pressure valves	2 x 5,280 =	10,560
Total Other Major Equipment		158,912

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 6B -	IG generator to dock	200 ft (constant)
	Dock to incinerator	660 ft to 1,400 ft

Example:

Model 6B - low piping cost

IG eductor feed	2 x 1,311 =	2,622
IG water line		1,311
Hydrocarbon vapor feed	2 x 1,246.5 =	2,693
Eductor discharge	2 x 2,683 =	5,366
IG feed header		36,456
Natural gas to incinerator		54,120
IG generator to dock	$26.93/ft x 200 ft	5,386
Dock to incinerator	$52.55/ft x 600 ft	34,683
Total piping cost		142,637
Total piping cost (rounded)		143,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 5. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 6B

Explosionproof alarm		16,800
Vapor line oxygen probe		5,880
Barge header oxygen probes	2 x 5,880 =	11,760
Pressure - vaccum sensors	2 x 900 =	1,800
Total instrumentation		36,240

G. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering =	10 percent
Startup =	10 percent
Contingencies =	5 percent
	25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 6B

Throughput =	2,000 hr/yr x 4,000 bbl/hr = 8,000,000 bbl/yr
Number vessels =	8,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
=	21.92 vessels
TCI =	$168,000/vessel x 21.92 vessels = 3,682,000
TCI (rounded) =	3,682,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[4] Assumed 2,000 operating hours per year.[5]

Example:

Model 6B

2,000 hr/yr|8 hr/shift = 250 shifts/yr	
250 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$1,863/yr
For operating both incinerator and IG generator	x 2
From 1988 dollars to 1987 dollars	x (323.8/342.5)
	$3,523/yr
Labor (rounded)	$3,520/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by 2 to compensate for the inert gas generator. This number is again multiplied by 2 to compensate for parts.

Example:

Model 6B

$40,800/yr	From UTD, annual preventive maintenance costs	
- 8,000/yr	Incinerator scrubber maintenance	
$32,800/yr		
Maintenance parts and labor		$1,782/yr
For maintaining both incinerator and IG generator		x 2
For parts		x 2
From 1989 dollars to 1987 dollars		(323.8/342.5
		$6,741/yr

Total maintenance = $32,800 + $6,741 = $39,541/yr
Total maintenance (rounded) = $39,500/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr = size (ft^3/hr)/8.6 ft^3

Example

Model 6B

Percent of operating capacity = 8,000 bbl/hr|16,000 bbl/hr =	0.5
IG fuel = 61,540 ft^3/hr|8.6 x 2,000 hr/yr x $3.43/1,000 ft^3 x 0.5 =	24,545
Incinerator pilot light =	7,650
Total natural gas cost =	32,195
Total natural gas cost (rounded) =	32,200

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage agreed for model 5. Electricity costs for incinerator feed fans was taken from the UTD estimate for model 5A and adjusted to a rate of $0.0472/kWh.[2,8]

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Model 6B

Electrical costs

$$\left[\frac{\$3,000}{\$0.08/kWh} + \left(\left\{\frac{61,540\ ft^3/hr \times 455}{508,600} - 16\right\} \times 2,000\ hr/yr\right)\right] \times \$0.0472/kWh \times 0.5 = \$2,728/yr$$

Electrical costs (rounded) = $2,730/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 6B (low end)

CRC = [142,637 x 0.1175] + [(932,722 - 142,637) x 0.1627] = $148,055
CRC (rounded) = $148,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3.

Model 6B

Capital recovery	$19,750/vessel x 21.92 vessels =	$433,000
Maintenance	$9,600/vessel x 21.92 vessels =	210,000
Vessel retrofit TAC =		643,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 6B (crude oil)

(1.0/1,000 gal) x (8,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb) x 0.98 = 149 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 6B (terminal only)

$$\frac{289,853\ (\$/yr)}{149\ (Mg/yr)} = 1,945\ (\$/Mg)$$

Model 6B (terminal and ships)

$$\frac{932,772\ (\$/yr)}{149\ (Mg/yr)} = 6,260\ (\$/Mg)$$

Cost Methodology Documentation (Model 6C)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 6C

Incinerator capital cost installation	
(220,400 + [11.57 x 3,550 scfm]) x 323.8/342.5 =	218.074
Installation	71,964
Total installed cost (rounded)	290,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices.[5,6,9] An additional 20 percent was added for installation.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	79,900
	(automatic flow control)	4,110
Total:		84,010

Model 6C IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model SC this maximum loading rate is 4,000 bbl/hr (1 barge @ 4,000 bbl/hr/barge).

VOC gas stream flow is calculated as:

4,000 bbl/hr x 5.615 ft^3/bbl = 22,460 ft^3/hr

Inert gas required is calculated as:

22,460 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 30,770 ft^3/hr IG

Model 6C IG cost: $84,010(30,770/60,000)^{0.7} \times (323.8/322.7) \times 1.2 = 63,383$

Model 6C IG cost (rounded): 63,400

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 6C	
Assume 6 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 123,000 ft^3/min (oversized)	-1,000 gal/min
Average velocity	11.71 ft/sec
Reynolds No.:	595
Fricton factor:	0.1
Pressure drop	43 psi
Pump cost = $6,000 x 1.4 x (323.8/355.4)	7,653
Pipe cost = $1,200/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	8,188
Total	15,841
Total (rounded)	15,800

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 6C

Incinerator booster fan		25,000
Incinerator detonation arrestor		34,960
Incinerator trip valve		10,680
3-way inert gas valve		6,500
Eductors	1 x 6,250 =	6,250
Detonation arrestors	1 x 24,076 =	24,076
Barge hydrocarbon vapor headers	1 x 5,280 =	5,280
Back pressure valves	1 x 5,280 =	5,280
Total Other Major Equipment		118,026

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 6C - IG generator to dock200 ft (constant)
Dock to incinerator 660 ft to 1,400 ft

Example:

Model 6C - low piping cost

IG eductor feed		1,311
IG water line		1,311
Hydrocarbon vapor feed		1,346.5
Eductor discharge		2,683
IG feed header		36,456
Natural gas to incinerator		54,120
IG generator to dock	$19.56/ft x 200 ft	3,912
Dock to incinerator	$26.93/ft x 660 ft	17,774
Total piping cost		118,913
Total piping cost (rounded)		119,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 5. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 6C

Explosionproof alarm		16,800
Vapor line oxygen probe		5,880
Barge header oxygen probes	1 x 5,880 =	5,880
Pressure - vaccum sensors	1 x 900 =	900
Total instrumentation		29,460

G. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering =	10 percent
Startup =	10 percent
Contingencies =	5 percent
	25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 6C

Throughput =	1,000 hr/yr x 4,000 bbl/hr = 4,000,000 bbl/yr
Number vessels =	4,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
=	10.96 vessels
TCI =	$168,000/vessel x 43.84 vessels = 1,841,000
TCI (rounded) =	1,840,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[4] Assumed 1,000 operating hours per year.[5]

Example:

Model 6C

1,000 hr/yr|8 hr/shift = 125 shifts/yr	
125 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$932/yr
For operating both incinerator and IG generator	x 2
From 1989 dollars to 1987 dollars	x (323.8/342.5)
	$1,761/yr
Labor (rounded)	$1,761/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by 2 to compensate for the inert gas generator. This number is again multiplied by 2 to compensate for parts.

Example:

Model 6C

$40,800/yr	From UTD, annual preventive maintenance costs
- 8,000/yr	Incinerator scrubber maintenance
$32,800/yr	

Maintenance parts and labor	$891/yr
For maintaining both incinerator and IG generator	x 2
For parts	x 2
From 1989 dollars to 1987 dollars	(323.8/342.5
	$3,369/yr

Total maintenance = $32,800 + $3,369 = $36,169/yr
Total maintenance (rounded) = $36,200/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr = size (ft^3/hr)/8.6 ft^3

Example

Model 6C

Percent of operating capacity = 4,000 bbl/hr|4,000 bbl/hr =	1.0
IG fuel = 30,770 ft^3/hr|8.6 x 1,000 hr/yr x $3.43/1,000 ft^3 x 1.0 =	12,272
Incinerator pilot light =	7,650
Total natural gas cost =	19,922
Total natural gas cost (rounded) =	19,900

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage agreed for model 5. Electricity costs for incinerator feed fans was taken from the UTD estimate for model 5A and adjusted to a rate of $0.0472/kWh.[2,8]

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Model 6C

Electrical costs

$$\left[\frac{\$3,000}{\$0.08/kWh} + \left(\left\{\frac{30,770\ ft^3/hr \times 455}{508,600} - 16\right\} \times 1,000\ hr/yr\right)\right] \times \$0.0472/kWh \times 1.0 = \$2,311/yr$$

Electrical costs (rounded) = $2,300/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 6C (low end)

CRC = [118,026 x 0.1175] + [(794,572 - 118,026) x 0.1627] = $123,928
CRC (rounded) = $124,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3.

Model 6C

Capital recovery	$19,700/vessel x 10.96 vessels =	$216,000
Maintenance	$9,600/vessel x 10.95 vessels =	105,000
Vessel retrofit TAC =		321,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 6C (crude oil)

(1.0/1,000 gal) x (4,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb) x 0.98 = 75 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 6C (terminal only)

$$\frac{238,636\ (\$/yr)}{75\ (Mg/yr)} = 3,182\ (\$/Mg)$$

Model 6C (terminal and ships)

$$\frac{560,096\ (\$/yr)}{75\ (Mg/yr)} = 7,468\ (\$/Mg)$$

Cost Methodology Documentation (Model 7A)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 7A

Incinerator capital cost	
(220,400 + [11.57 x 6,432 scfm]) x 323.8/342.5 =	279,000
Installation	92,000
Total installed cost (rounded)	371,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices.[5,6,9] An additional 20 percent was added for installation. Model 7A is assumed to have two similarly sized units for reasons explained in the text.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	79,900
	(automatic flow control)	4,110
Total:		84,010

Model 7A IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model 7A this maximum loading rate is 29,000 bbl/hr.

VOC gas stream flow is calculated as:

29,000 bbl/hr x 5.615 ft^3/bbl = 162,835 ft^3/hr

Inert gas required is calculated as:

162,835 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 223,084 ft^3/hr IG

Model 7A IG cost: $84,000(223,084/60,000)^{0.7} \times 2 \times (323.8/322.7) \times 1.2 = 312,226$

Model 7A IG cost (rounded): 312,000

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 7A	
Assume 10 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 632,000 ft^3/min (oversized)	~5,000 gal/min
Average velocity	21.1 ft/sec
Reynolds No.:	1,785
Fricton factor:	0.035
Pressure drop	25 psi
Pump cost = $12,500 x 1.4 x (323.8/355.4)	15,944
Pipe cost = $1,950/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	13,305
Total	29,249
Total (rounded)	29,200

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 7A

Incinerator booster fan	112,680
Incinerator trip valve	26,000
3-way inert gas valve	7,800
Incinerator booster fans	75,000
Eductor (barge)	6,250
Eductor (ship)	18,750
Detonation arrestor (barge)	24,076
Detonation arrestor (ship)	33,460
Trip valve (barge)	5,280
Trip valve (ship)	10,680
Back pressure valve (barge)	5,280
Back pressure valves (ship)	11,600
Total Other Major Equipment	336,856

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 7A -	IG generator to dock	200 ft (constant)
	Dock to incinerator	660 ft to 1,400 ft

Example:

Model 7A - low piping cost

IG eductor feed (barge)		1,311
IG eductor feed (ship)		2,683
Hydrocarbon vapor feed (barge)		1,342
Hydrocarbon vapor feed (ship)		3,712
Eductor discharge (barge)		2,683
Eductor discharge (ship)		7,423
Barge dock infeed header		84,705
IG recirculating line		6,417
Barge IG/hydrocarbon header		89,488
Dock to incinerator	($127.71/ft x 660 ft) =	84,289
Natural gas line	($45/ft x 900 ft) =	40,500
Inert gas to dock	($76.465/ft x 200 ft) =	15,293
Piping (total)		339,846
Piping (rounded)		340,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 7. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 7A

Explosionproof alarm (barge)	35,000
Explosionproof alarm (ship)	21,000
Header oxygen probe (barge)	5,880
Header oxygen probe (ship)	5,880
Pressure - vaccum sensor	900
Pressure - vaccum sensor (ship)	900
Total instrumentation	69,560

G. Engineering, Startup, and Contingencies

Per the UTD cost estimate, engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering = 10 percent
Startup = 10 percent
Contingencies = 5 percent
25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Barges
Barges throughput = 1,000 hr/yr x 4,000 bbl/hr x 1 = 4,000,000 bbl/yr
No. barges = 4,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
= 10.96 barges
Ships
Ships throughput = 1,000 hr/yr x 25,000 bbl/hr = 25,000,000 bbl/yr
No. ships = 25,000,000 bbl/yr|365 d/yr|20,000 bbl/vessel/d
= 3.42 ships

TCI = $168,000/barge x 10.96 barges + $426,000/ship x 3.42 ships =
TCI (rounded) = 3,300,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[5] Assumed 2,000 operating hours per year.[2]

Example:

Model 7A

1,000 hr/yr|8 hr/shift = 125 shifts/yr	
125 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$931.5/yr
For operating both incinerator and IG generator	x 2
From 1989 dollars to 1987 dollars	x (323.8/342.5)
	$1,762/yr
Labor (rounded)	$1,760/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by two to compensate for the inert gas generator. This number is again multiplied by two to compensate for parts.

Example:

Model 7A

$64,800/yr From UTD, annual preventive maintenance costs	
Maintenance parts and labor	
125 shifts/yr x 0.5 hr/shift x $14.26/hr	$891/yr
For maintaining both incinerator and IG generator	x 2
For parts	x 2
From 1989 dollars to 1987 dollars	(323.8/342.5
	$3,369/yr

Total maintenance = $64,800 + $3,369 = $68,169/yr
Total maintenance (rounded) = $68,200/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr = size (ft^3/hr)/8.6 ft^3

Example

Model 7A

Percent of operating capacity = 29,000 bbl/hr|29,000 bbl/hr =	1.0
IG fuel = 223,084 ft^3/hr|8.6 x 1,000 hr/yr x $3.43/1,000 ft^3 x 1.0 =	88,974
Incinerator pilot light =	7,650
Total natural gas cost =	96,624
Total natural gas cost (rounded) =	96,600

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage appeared to be understated for Model 7A. The incinerator fan electricity usage was subsequently recalculated for Model 7A.

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Incinerator booster fan consumption

0.0017 x 6,432 x 30/6 = 37.6 kw
Electrical costs

$$[37.6 + \frac{223,084 \times 455}{508,600} - 16\}] \times 1,000\ hr/yr)] \times \$0.0472/kWh \times 1.0 = \$10,441\ yr$$

Electrical costs (rounded) = $10,400/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 7A (low end)

CRC = [339,846 x 0.1175] + [(1,823,044 - 339,846) x 0.1627] = $281,302
CRC (rounded) = $281,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-11.

Model 7A

Capital recovery =	$19,750/vessel x 10.96 barges =	$216,460
	$50,038/ship x 3.42 ships =	$171,130
Maintenance	$9,600/vessel x 10.96 barges =	105,216
	$14,400/ship x 3.42 ships =	49,248
Vessel retrofit TAC (rounded) =		542,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 7A (gasoline)

([3.4/1,000 gal x 4,000,000 bbl/yr] + [1.8 lb/1,000 gal x 25,000,000 bbl/yr] x 42 gal/bbl x 0.000453 Mg/lb) x 0.98 = 1,093 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 7A (terminal only)

$$\frac{573,178 \ (\$/yr)}{1,093 \ (Mg/yr)} = 525 \ (\$/Mg)$$

Model 7A (terminal and ships)

$$\frac{1,115,315 \ (\$/yr)}{1,093 \ (Mg/yr)} = 1,021 \ (\$/Mg)$$

Cost Methodology Documentation (Model 7B)

I. Capital Costs

A. Incinerator

The incinerator capital costs are taken from the OAQPS Control Cost Manual. The installed incinerator cost was calculated by adding 33 percent to the capital cost.

Example:

Model 7B

Incinerator capital cost (220,400 + [11.57 x 14,638 scfm]) x 323.8/342.5 =	338,481
Installation	121,599
Total installed cost (rounded)	490,000

B. Inert Gas Generators

The capital costs for inert gas were taken from Richardson's, adjusted for increased size by EPA methodology, and converted to 1987 dollars using Chemical Engineering indices.[5,6,9] An additional 20 percent was added for installation. Model 7B is assumed to have four similarly sized units for reasons explained in the text.

Example:

Richardson's IG size:	60,000 ft^3/hr	
Richardson's IG cost:	(explosionproof)	79,900
	(automatic flow control)	4,110
Total:		84,010

Model 7B IG size:

The size of the IG generator is based upon the terminal's maximum loading rate. For model 7B this maximum loading rate is 66,000 bbl/hr.

VOC gas stream flow is calculated as:

66,000 bbl/hr x 5.615 ft^3/bbl = 370,590 ft^3/hr

Inert gas required is calculated as:

370,590 ft^3/hr x 1.37 ft^3 IG/ft^3 VOC's = 507,708 ft^3/hr IG

Model 7B IG cost: $84,000(507,708/4/60,000)^{0.7} \times 4 \times (323.8/322.7) \times 1.2 = 683,566$

Model 7B IG cost (rounded): 684,000

C. Water System

A water system to provide brackish water to the inert gas generator scrubber is costed for. The water system consists of a pump and piping to and from the inert gas generator. Pump costs from Perry's are multiplied by a factor of 1.4 for stainless construction.[10] Pipe costs from Richardson's are multiplied by 1.7 to account for fittings and installation. All costs are corrected to 1987 dollars.

Example:

Model 7B

Assume 10 in. pipe	
Flow = 8 gal/min/1,000 ft^3/min x 632,000 ft^3/min (oversized)	~5,000 gal/min
Average velocity	21.1 ft/sec
Reynolds No.:	1,785
Fricton factor:	0.035
Pressure drop	25 psi
Pump cost = $12,500 x 1.4 x (323.8/355.4)	15,944
Pipe cost = $1,950/100 ft x 200 ft x 1.7 x (323.8/322.7) x 2	13,305
Total	29,249
Total (rounded)	29,200

D. Other Major Equipment

The installed capital costs for major equipment other than the incinerator and inert gas generator are taken from the UTD cost estimate.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the incinerator booster fan, detonation arrestor, incinerator trip valve, and three-way inert gas valve. Vessel based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when an inert gas generator is used.

Example:

Model 7B

Incinerator detonation arrestor		112,680
Incinerator trip valve		26,000
3-way inert gas valve		7,800
Incinerator booster fans		75,000
Eductors (barge)	4 x 6,250	25,000
Eductor (ship)	2 x 18,750	37,500
Detonation arrestor (barge)	4 x 24,076	96,304
Detonation arrestor (ship)	2 x 33,460	66,920
Trip valve (barge)	4 x 5,280	21,120
Trip valve (ship)	2 x 10,680	21,360
Back pressure valve (barge)	4 x 5,280	21,120

Back pressure valves (ship)	2 x 11,600	23,200
Total Other Major Equipment		534,004

E. Piping

The installed capital costs of piping are taken from the UTD estimate.[2] The lengths of certain runs of pipe are varied as follows. The IG generator was assumed to be mounted 200 ft from the dock. The pipe carrying the inert gas is of the same specifications as in the UTD estimate, with the cost adjusted linearly for the shorter distance.

Model 7B - IG generator to dock200 ft (constant)
Dock to incinerator 660 ft to 1,400 ft

Example:

Model 7B - low piping cost

IG eductor feed (barge)	4 x 1,311 =	5,244
IG educator feed (ship)	2 x 2,683 =	5,366
Hydrocarbon vapor feed (barge)	4 x 1,324 =	5,368
Hydrocarbon vapor feed (ship)	2 x 3,712 =	7,424
Eductor discharge (barge)	4 x 2,683 =	10,732
Eductor discharge (ship)	2 x 7,423 =	14,846
Barge dock infeed header		84,705
IG recirculating line		6,417
Barge IG/hydrcarbon header		89,488
Dock to incinerator	($178,975/ft x 660 ft) =	118,124
Natural gas line	($45/ft x 900 ft) =	40,500
Inert gas to dock	($127.71/ft x 200 ft)	25,542
Piping (total)		413,756
Piping (rounded)		414,000

F. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate. The number costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 7. The required number of vessel-associated oxygen probes and pressure-vacuum sensors is based on the maximum number of loading vessels. However, the per item costs are the same as those provided in the UTD estimate.

Example:

Model 7B

Explosionproof alarm (barge)		35,000
Explosionproof alarm (ship)		21,000
Header oxygen probe (barge)	4 x 5,880 =	23,520
Header oxygen probe (ship)	2 x 5,880 =	11,760
Pressure - vaccum sensor	4 x 900 =	3,600
Pressure - vaccum sensor (ship)	2 x 900 =	1,800
Total instrumentation		96,680

G. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering =	10 percent
Startup =	10 percent
Contingencies =	5 percent
	25 percent

H. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Barges
Barges throughput = 2,000 hr/yr x 4,000 bbl/hr x 2 = 16,000,000 bbl/yr
No. barges = 16,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d
= 43.84 barges
Ships
Ships throughput = 2,000 hr/yr x 25,000 bbl/hr = 50,000,000 bbl/yr
No. ships = 50,000,000 bbl/yr|365 d/yr|20,000 bbl/vessel/d
= 6.85 ships

TCI = $168,000/barge x 43.84 barges + $426,000/ship x 6.85 ships =
TCI (rounded) = 10,300,000

II. Annual Costs

Direct operating costs

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[5] Assumed 2,000 operating hours per year.[2]

Example:

Model 7B

2,000 hr/yr|8 hr/shift = 250 shifts/yr	
250 shifts/yr x 0.5 hr/shift x $12.96/hr x 1.15 =	$1,863/yr
For operating both incinerator and IG generator	x 2
From 1989 dollars to 1987 dollars	x (323.8/342.5)
	$3,523/yr
Labor (rounded)	$3,520/yr

B. Maintenance

The costs of maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor

is multiplied by 2 to compensate for the inert gas generator. This number is again multiplied by 2 to compensate for parts.

Example:

Model 7B

$64,800/yr From UTD, annual preventive maintenance costs	
Maintenance parts and labor	
250 shifts/yr x 0.5 shift x $14.26/hr	$1,782/yr
For maintaining both incinerator and IG generator	x 2
For parts	x 2
From 1989 dollars to 1987 dollars	(323.8/342.5)
	$6,739/yr

Total maintenance = $64,800 + $6,739 = $71,539/yr
Total maintenance (rounded) = $71,500/yr

C. Natural Gas

The natural gas costs were developed by estimating the amount of natural gas necessary for the IG generator and adding incinerator pilot light fuel costs from the UTD cost estimate.[2,7] The equation relating natural gas usage to inert gas generated was derived from data provided by Industrial Gas Systems.[7]

IG generator fuel usage (ft^3/hr = size (ft^3/hr)/8.6 ft^3

Example

Model 7B

Percent of operating capacity = 33,000 bbl/hr|66,000 bbl/hr =	0.5
IG fuel = 507,708 ft^3/hr|8.6 x 2,000 hr/yr x $3.43/1,000 ft^3 x 0.5 =	202,493
Incinerator pilot light =	7,650
Total natural gas cost =	210,143
Total natural gas cost (rounded) =	210,000

D. Electricity

The electricity usage of the incinerator feed fans as specified in the UTD estimate was checked using methodology in the OAQPS control cost manual.[2,5] The usage appeared to be understanded for Model 7B. The incinerator fan electricity usage was subsequently recalculated for Model 7B.

An equation for IG generator electrical usage was extrapolated from data provided by Industrial Gas Systems.[7] Electrical usage for large generators was calculated as

$$kW/hr = \left(\frac{IG\ size\ ft^3/hr)\ x\ 455}{508,600}\right) - 16$$

Example:

Incinerator booster fan consumption

0.00117 x 14,638 x 30/6 = 85.6 kw

Electrical costs

$$[85.6 + \{\frac{507,708 \times 455}{508,600} - 16\}] \times 2,000 \text{ hr/yr})] \times \$0.0472/\text{kWh} \times 0.5 = \$24,725 \text{ yr}$$

Electrical costs (rounded) = $24,700/yr

E. Overhead

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.[5]

F. Property Taxes, Insurance, and Administration

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.[5]

G. Capital Recovery Charge

The capital recovery charge is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life.

Capital recovery factors

0.1175 - piping
0.1627 - all other equipment

Example:

Model 7B (low end)

CRC = [414,000 x 0.1175] + [(2,809,173 - 414,000) x 0.1627] = $438,443
CRC (rounded) = $438,000

H. Vessel Retrofit Total Annual Cost (TAC)

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-11.

Model 7B

Capital recovery =	$19,750/barge x 43.84 barges =	$865,840
	$50,038/ship x 6.85 ships =	342,760
Maintenance	$9,600/barge x 43.84 barges =	420,864
	$14,400/ship x 6.85 ships =	98,640
Vessel retrofit TAC (rounded) =		1,730,000

I. Emission Reduction

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 98 percent.

Example

Model 7B (gasoline)

([3.4/1,000 gal) x 16,000,000 bbl/yr] + [1.8 lb/1,000 gal x 50,000,000 bbl/yr]) x 42 gal/bbl x 0.000453 Mg/lb) x 0.98 = 2,692 Mg/yr

J. Cost Effectiveness

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example

Model 7B (terminal only)

$$\frac{905,776\ (\$/yr)}{2,692\ (Mg/yr)} = 336\ (\$/Mg)$$

Model 7B (terminal and ships)

$$\frac{2,632,970\ (\$/yr)}{2,692\ (Mg/yr)} = 978\ (\$/Mg)$$

APPENDIX C. Carbon Adsorber Design Characteristics and Adsorber Capital Costs

CARBON ADSORBER DESIGN CHARACTERISTICS AND ADSORBER CAPITAL COSTSa

Model terminal	Total waste gas flow rate, Q (ft^3/min)	Inlet gasoline mass flowrate, m_{voc} (lb/hr)	Density of gasoline vapor, $\rho_{gasoline}$ (lb/ft^3)	Volumetric flowrate of gasoline $q_{gasoline}$ (ft^3/min)	Inlet concentration of gasoline, $c_{gasoline}$ (ppm)	Partial pressure of gasoline vapor, $p_{gasoline}$ (psia)	Equilibrium capacity, w_e (lb VOC/lb carbon)	Working capacity, w_c (lb VOC/lb carbon)
5A	1,497	2,285	0.1706	223.2	149,000	2.19	0.31	0.1085
5B	749	1,142	0.1706	111.6	149,000	2.19	0.31	0.1085
5C	374	571	0.1706	55.79	149,000	2.19	0.31	0.1085
7A	2,714	2,461	0.1706	240.4	88,600	1.30	0.29	0.10
7B	6,177	6,085	0.1706	592.3	95,900	1.41	0.29	0.10

[a]Complete documentation of all of the design variables above is provided in Appendix D.

CARBON ADSORBER DESIGN CHARACTERISTICS AND ADSORBER CAPITAL COSTSa
(continued)

Model terminal	Desorption time, θ_D (hours)	Adsorption time, θ_A (hours	No. of adsorbing beds, N_A	No. of desorbing beds, N_D	Carbon requirement, M_c (lb)	Carbon requirement per bed, M'_c (lb)	Total waste flow per bed, Q' (ft^3/min)	Vessel diameter, D (ft)
5A	1.00	1	1	1	42,120	21,060	1,497	8.73
5B	1.00	1	1	1	21,060	10,500	749	6.17
5C	1.00	1	1	1	10,500	5,250	374	4.37
7A	0.67	1	3	2	40,410	8,080	905	6.79
7B	0.67	1	3	3	99,500	19,920	2,059	10.24

[a]Complete documentation of all of the design variables above is provided in Appendix D.

CARBON ADSORBER DESIGN CHARACTERISTICS AND ADSORBER CAPITAL COSTSa
(continued)

Model terminal	Carbon bed thickness, t_D, (ft)	Vessel length, L (ft)	Superficial bed velocity, v_b (ft/min)	Surface area, S (ft^2)	Cost of carbon, C_c ($1987)	Cost per vessel C_v ($1987)	Cost of adsorbert and carbon C_A ($1987)
5A	11.72	15.72	25	551	76,740	33,510	316,400
5B	11.72	15.72	25	365	38,370	24,310	210,000
5C	11.72	15.72	25	246	19,190	17,870	145,400
7A	7.45	10.45	25	295	73,640	20,620	359,400
7B	8.06	11.6	25	521	181,500	32,060	623,000

[a]Complete documentation of all of the design variables above is provided in Appendix D.

APPENDIX D.

Documentation of Costs for a Carbon Adsorption-Based Technology

GLOSSARY OF SYMBOLS AND ABBREVIATIONS

C_A	total adsorber equipment cost, $1,987
C_c	cost of carbon, $1,987
C_{cl}	labor cost of replacing carbon, $/lb x M_c
C_{cw}	cost of cooling water
cfm	cubic feet per minute (ft^3/min)
$C_{gasoline}$	inlet concentration of gasoline
C_p	cost of piping
C_r	cost of carbon replacement
CRC	capital recovery charge, $1,987
CRF_c	capital recovery factor for carbon (based on 2-yr life and 10 percent interest rate)
CRF_p	capital recovery factor for piping (based on 20-yr life and 10 percent interest rate)
CRF_s	system capital recovery factor (based on 10-yr equipment life and 10 percent interest rate)
C_s	steam cost, $1,987
C_v	cost per vessel, $1,987
D	adsorber diameter, ft
ρ_b	carbon bulk density, lb/ft^3
$\rho_{gasoline}$	density of gasoline vapor, lb/ft^3
ΔP_b	pressure drop through the bed, inches of water
ΔP_s	total system pressure drop, inches of water
E	adsorber control efficiency, assumed to be 95 percent
eff	combined pump-motor efficiency, percent
f_1	ratio of 1987 to 1989 cost indices
f_2	terminal annual operating capacity, percent
H	required head, ft
hp	horsepower
hp_{cf}	horsepower needed to run the cooling fan, hp
hp_{cwp}	horsepower needed to run the cooling water pump, hp
kWh	kilowatt-hours
kWh_{cf}	electricity needed to run the cooling fan, kilowatt-hours/yr

kWh_{cwp}	electricity needed to run the cooling water pump, kWh/yr
kWh_{sf}	electricity needed to run the system fan, kWh/hr
L	adsorber length, ft
M	molecular weight, lb/lb-mole
M_c	carbon requirement, lb
M'_c	carbon requirement per bed, lb
MG	megagram
m_{voc}	gasoline mass flow rate to the adsorber, lb/hr
N_A	number of adsorbing beds
N_D	number of desorbing beds
P	pressure, atm
$p_{gasoline}$	partial pressure of gasoline, psia
p_s	steam price, dollars per thousand lb of steam
p_{voc}	value of recovered product, $/lb
ppm	parts per million
psia	$lb/in.^2$
Q	total waste gas flow, ft^3/min
Q'	total waste gas flow per bed, ft^3/min
q_{cw}	cooling water flow, gallons/yr (gal/yr)
$q_{gasoline}$	volumetric flowrate of gasoline, ft^3/min
R	gas constant, 0.7302 ft^3 atm/lb-mole °R
R_c	ratio of total adsorber equipment cost to the cost of the adsorber vessels
RC	recovery credit, $1,987
°R	degrees Rankin, °F + 459.57
S	surface area of each adsorber vessel, ft^2
T	temperature, °R
$t_{a,g}$	access/gas distribution allowance, ft
TAC	total annual cost
t_b	carbon bed thickness, ft
TCI	total capital investment
θ_A	adsorption time, hours
θ_{cf}	annual operating time of the cooling fan, hours
θ_{cwp}	annual operating time of the cooling water pump, hours

θ_D	desorption time, hours
θ_s	total annual terminal operating time, hr/yr
TkWh	total annual electricity consumption, kWh/yr
UTD document	document that presents costs of controlling vapor using incineration
v_b	superficial bed velocity, ft/min
w_c	working capacity of the carbon, lb VOC/lb carbon
w_e	equilibrium capacity of the carbon, lb VOC/lb carbon
y_{gas}	mole fraction of gasoline vapor in total waste gas flow

DOCUMENTATION FOR CARBON ADSORPTION COSTS: MODEL TERMINAL 5A

I. CAPITAL COSTS

A. Carbon Adsorber

1. Gasoline mass flow rate to adsorber (m_{voc}), lb/hr:

$$m_{voc} = (4 \text{ barges}) \times (4{,}000 \text{ bbl/hr}) \times \frac{3.4 \text{ lb}}{1{,}000 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}}$$

$$m_{voc} = 2{,}284.8 \text{ lb/hr}$$

2. Total waste gas flow (Q), ft^3/m:

$$Q = (4 \text{ barges}) \times (4{,}000 \text{ bbl/hr}) \times (5.615 \text{ ft}^3/\text{bbl}) \times \left(\frac{1 \text{ hr}}{60 \text{ min}}\right)$$

$$Q = 1{,}497.33 \text{ ft}^3/\text{min}$$

3. Volumetric flowrate of gasoline ($q_{gasoline}$), ft^3/min:

$$q_{gasoline} = \frac{m_{voc}}{\rho_{gasoline}} \times \frac{60 \text{ min}}{\text{hr}}$$

First, calculate density of gasoline vapor, $\rho_{gasoline}$, lb/ft^3:

$$\rho_{gasoline} = \frac{MP}{RT} \quad \text{(ideal gas law)}$$

where:

$$M = 66 \text{ lb/lb-mole, and } T = 70°F$$

$$\rho_{gasoline} = \frac{66 \frac{\text{lb}}{\text{lb-mole}} \times 1 \text{ atm}}{\frac{0.7302 \text{ ft}^3 \text{ atm}}{\text{lb-mol °R}} \times (70 + 459.67)°R}$$

$$\rho_{gasoline\ vapor} = 0.17065 \text{ lb/ft}^3$$

$$\therefore q_{gasoline} = \frac{2{,}284.8 \text{ lb/hr}}{0.17065 \text{ lb/ft}^3} \times \frac{1 \text{ hr}}{60 \text{ min}} = 223.15 \text{ ft}^3/\text{min}$$

4. Inlet concentration of gasoline ($C_{gasoline}$), ppm:

$$C_{gasoline} = \frac{q_{gasoline}}{Q} \times 10^6 = \frac{223.15}{1,497.33} \times 10^6 = 149,030 \text{ ppm}$$

5. Partial pressure of gasoline ($p_{gasoline}$), psia:

$$p_{gasoline} = y_{gas} \times P$$

y_{gas} = mole fraction of gasoline in total flow
P = total pressure (atmospheric)

$$p_{gasoline} = \frac{149,030 \text{ ppm}}{1 \times 10^6 \text{ ppm}} \times 14.696 \text{ psia}$$

$$p_{gasoline} = 2.19 \text{ psia}$$

6. Equilibrium capacity (w_e) of the carbon, lb VOC/lb carbon:

$$w_e = 31 \text{ percent} = 31 \text{ lb VOC/100 lb carbon}$$

$$= 0.31 \frac{\text{lb VOC}}{\text{lb carbon}}$$

[As determined from the n-pentane isotherm (capacity weight percent vs. partial pressure, psia) for n-pentane adsorption on Calgon's BPL activated carbon]. Note: the n-pentane isotherm was used to represent gasoline vapor since n-pentane is a major constituent in gasoline vapor.

7. Working capacity (w_c) of the carbon, lb VOC/lb carbon:

Because gasoline contains relatively high vapor-pressure constituents and the desorption cycles are very short, assume that the working capacity is about 35 percent of the equilibrium capacity.

$$\therefore w_c = 0.35 \times \frac{31}{100} = \frac{10.85 \text{ lb VOC}}{100 \text{ lb carbon}} = 0.1085 \frac{\text{lb VOC}}{\text{lb carbon}} = w_c$$

8. Number of adsorbing and desorbing beds and adsorption time:

The number of adsorbing and desorbing beds (N_A and N_D, respectively) and the adsorption time (θ_A) were determined by trial and error. Due to shipping restrictions, vessel diameters rarely exceed 12 feet, while their length is generally limited to 50 feet.[1] The number of adsorbing and desorbing vessels and adsorption time directly affect vessel dimensions. To obtain "reasonable" vessel dimensions, very short adsorption and desorption times were necessary (i.e., 1-hour adsorption and desorption cycles). At longer adsorption times, the bed thickness and the pressure drop through the bed increased sharply. At higher pressure drops, electricity costs rapidly increased due to the enormous amount of electricity needed to run the cooling water pump. For model terminal 5A, the number of adsorbing beds = 1, and the number of desorbing beds = 1; the adsorption and desorption times both equal 1 hour. Ideally, the optimum regeneration frequently for fixed bed adsorbers treating streams with moderate to high VOC inlet loadings is once every 8 to 12 hours.[1] However, at adsorptions times in this range the lengths of the vessels were very high (greater than 300 feet) and the diameters very small (less than a foot).

The desorption time, θ_D, is set once the number of adsorbing and desorbing units and the adsorption time are determined, as follows:

$$\theta_D \leq \theta_A \left(\frac{N_D}{N_A}\right)$$

where:

θ_A = adsorption time
N_D = number of desorbing units
N_A = number of adsorbing units

$$\therefore \theta_D \leq 1 (\tfrac{1}{1})$$

θ_D = 1 hour

9. Carbon requirement (M_c), lb:

$$M_c = \frac{m_{voc}}{w_c} \theta_A \left(1 + \frac{N_D}{N_A}\right)$$

where:

m_{voc} = gasoline vapor flowrate (2,284.8 lb/hr)

w_c = working capacity of carbon $\left(0.1085 \frac{\text{lb VOC}}{\text{lb carbon}}\right)$

θ_A = adsorption time (1 hour)
N_D = number of desorbing units (1)
N_A = number of adsorbing units (1 hour)

$$M_c = \frac{2{,}284.8 \text{ lb/hr}}{0.1085 \frac{\text{lb VOC}}{\text{lb carbon}}} \times 1 \text{ hour} \times \left(1 + \frac{1}{1}\right)$$

M_c = 42,116 lb of carbon

10. Cost of carbon (C_c):[1]

The cost of carbon in 1989 was approximately \$2.00/lb.[1] Therefore, the cost of the carbon is calculated as follows:

$$C_c = \$2.00/\text{lb} \times M_c \times f_1$$

where:

f_1 = ratio of 1987 to 1989 cost indices = 323.8/355.4

$$\therefore C_c = 2.00 \times 42{,}116 \times 323.8/355.4 = \$76{,}743$$

11. Carbon requirement per bed (M'_c), lb:

$$M'_c = \frac{M_c}{(N_A + N_D)} = \frac{42{,}116}{2} = 21{,}058 \ \frac{\text{lb of carbon}}{\text{bed}}$$

12. Total waste gas flow per bed (Q'), ft^3/min:

$$Q' = \frac{Q}{N_A} = \frac{1{,}497 \ ft^3/min}{1} = 1{,}497 \ ft^3/min = Q'$$

13. Superficial bed velocity (v_b), ft/min:

A superficial bed velocity of 25 ft/min was chosen by a "trial and error" basis. The superficial bed velocity, v_b, directly affected the pressure drop through the bed. At higher velocities (e.g., 50 to 100 ft/min) the pressure drop rose dramatically, which greatly increased annual electricity costs.

14. Adsorber vessel dimensions--diameter (D) and length (L), feet:

Because of the relatively low gas flowrate ($Q' < 9{,}000 \ ft^3/min$), it was more economical to design vertical rather than horizontal adsorber vessels.

For a vertical vessel, the diameter is calculated as follows:

$$D = \left(\frac{4Q'}{\pi \ v_b}\right)^{1/2} = \left(\frac{4 \times 1{,}497 \ ft^3/min}{\pi \times 25 \ ft/min}\right)^{1/2} = 8.73 \text{ feet} = D$$

The length (height) of the vessel is calculated using the following equation:

$$L = t_b + t_{a,g}$$

where:

t_b = carbon bed thickness in feet; and
$t_{a,g}$ = access/gas distribution allowance
= 2 to 6 ft (depending on vertical vessel diameter)

The carbon bed thickness is calculated as follows:

$$t_b = \frac{\text{volume of carbon}}{\text{cross-sectional area normal to flow}} = \frac{M'_c/\rho_b}{Q'/v_b}$$

where:

ρ_b = carbon bulk density = 30 lb/ft^3

$$\therefore\ t_b = \frac{(21{,}058/30)}{(1{,}497/25)} = 11.72 \text{ feet} = t_b$$

Assume that $t_{a,g}$ = 4 feet; then

$$L = 11.72 + 4 = 15.72 \text{ feet} = L$$

15. Surface area of each vessel (S), ft^2:

$$S = \pi D\ (L + D/2)$$

$$= \pi \times 8.73 \times (15.72 + 8.73/2) = 550.85 \text{ ft}^2$$

$$S = 551 \text{ ft}^2$$

16. Cost per vessel (C_v):[1]

$$C_v = 271 \times S^{0.778} \times f_1$$

where:

f_1 = ratio of 1987 to 1989 cost indices = 323.8/355.4;

and

$97 \leq S \leq 2{,}110\ ft^2$

$\therefore\ C_V = 271 \times (551)^{0.778} \times (323.8/355.4) = \$33{,}510$

Note: The costs are based on the assumption that the adsorber vessels will be made of 304 stainless steel.

17. Total adsorber equipment cost, (C_A), 1987 $:

$$C_A = R_C\ [C_C + N_A + N_D)(C_V]$$

where:

R_C = ratio of the total adsorber equipment cost to the cost of the vessels

C_C = cost of the carbon = $76,743

N_A = number of adsorbing units = 1

N_D = number of desorbing units = 1

C_V = cost of each unit = $33,510

R_C is calculated using the following formula:[1]

$$R_C = 5.82 \times Q^{-0.133}$$

$$= 5.82 \times (1{,}497\ ft^3/min)^{-0.133}$$

$$R_C = 2.201$$

$$\therefore\ C_A = 2.201 \times [76{,}743 + (2 \times 33{,}510)]$$

$$C_A = \$316{,}411$$

B. Other Major Equipment

The installed capital costs for major equipment other than the carbon adsorber are taken from the UTD cost estimate for incineration-based controls.[2] Certain equipment is required regardless of the number of loading vessels while other equipment is costed for based on maximum number of loading vessels. Required equipment includes the booster fan, detonation arrestor, and carbon adsorber trip valve. Vessel-based equipment includes eductors, barge detonation arrestors, hydrocarbon vapor headers, and backpressure valves. Cost for an incinerator scrubber and inert gas booster fans have been deleted as these items are no longer necessary when carbon adsorption is used.

Example:

Model 5A

Carbon adsorber booster fan		25,000
Carbon adsorber detonation arrestor		34,960
Carbon adsorber trip valve		10,680
Eductors	4 x 6,250 =	25,000
Detonation arrestors	4 x 24,076 =	96,304
Barge hydrocarbon vapor headers	4 x 5,280 =	21,120
Back pressure valves	4 x 5,280 =	21,120
Total other major equipment		234,184

C. Piping

The installed capital costs of piping are taken from the UTD estimate for incineration-based controls.[2] The piping costs are adjusted linearly as follows:

Model 5A - Dock to carbon adsorber: 660 ft to 1,400 ft

Example:

Model 5A - low piping cost

Hydrocarbon vapor feed	4 x 1,346.5 =	5,386
Eductor discharge	4 x 2,683 =	10,732

Dock to carbon adsorber	$52.55/ft x 660 ft	34,683
Total piping cost		50,800

D. Instrumentation

The capital costs for instrumentation are taken from the UTD cost estimate for incineration-based controls.[2] The costs of the vapor line oxygen probe and explosionproof alarm are the same as those for the original Marine Board Model Terminal 5. The required numbers of vessel-associated oxygen probes and pressure-vacuum sensors are based on the maximum number of loading vessels. However, the per-item costs are the same as those provided in the UTD estimate.

Example:

Model 5A		
Explosionproof alarm		16,800
Vapor line oxygen probe		5,880
Barge header oxygen probes	4 x 5,880 =	23,520
Pressure - vacuum sensors	4 x 900 =	3,600
Total Instrumentation		49,800

E. Engineering, Startup, and Contingencies

Engineering, startup, and contingencies are assumed to be 25 percent of the total installed equipment cost.[2]

Engineering = 10 percent
Startup = 10 percent
Contingencies = 5 percent
25 percent

F. Associated Vessel Total Capital Investment (TCI)

The capital costs associated with vessel retrofit are based on estimates in the UTD document.[2]

Example:

Model 5A

Throughput = 2,000 hr/yr x 8,000 bbl/hr = 16,000,000 bbl/yr

Number vessels = 16,000,000 bbl/yr|365 d/yr|1,000 bbl/vessel/d

= 43.84 vessels

TCI = $168,000/vessel x 43.84 vessels = 7,365,120

TCI (rounded) = $7,360,000

II. ANNUAL COSTS

A. Labor

The costs for operating labor and supervision are taken from the OAQPS control cost manual, 4th ed. and adjusted for base year.[4] Assumed 2,000 operating hours per year.[5]

Example:

Model 5A

2,000 hr/yr|8 hr/shift = 250 shifts/yr

250 shifts/yrx0.5 hr/shiftx$12.96/hx1.15 = $1,863/yr

From 1988 dollars to 1987 dollars x (323.8/342.5)

$1,762/yr

Labor (rounded) $1,762/yr

B. Maintenance

The costs for maintenance parts and labor are taken from the OAQPS control cost manual, 4th ed., and added to the maintenance costs in the UTD document.[2,5] Maintenance labor is multiplied by 2 to allow for parts.

Example:

Model 5A

$40,800/yr From UTD, annual preventive maintenance costs

- 8,000/yr Incinerator scrubber maintenance

$32,800/yr

Maintenance parts and labor

250 shifts/yr x 0.5 hr/shift x $14.26/hr	$1,782/yr
For parts	x 2
From 1988 dollars to 1987 dollars	(323.8/342.5)
$3,370/yr	

Total maintenance = $32,800 + $3,370 = $36,170/yr

Total maintenance (rounded) = $36,200/yr

C. Electricity Costs

In fixed-bed adsorbers, electricity is consumed by the system fan, bed drying/cooling fan, cooling water pump, and solvent pump(s).[1] Because the solvent pump horsepower (hp) is usually very small (<0.1 hp), its electricity consumption is assumed to be negligible.[1] The electricity requirements associated with the fans and the cooling water pump are detailed below and were calculated using equations presented in the OAQPS Control Cost Manual. Note that a factor of 0.50 was added to these equations so that annual costs (unlike capital costs) are based on actual terminal throughput rather than on the maximum throughput. The 0.5 factor represents the percent of terminal operating capacity.

1. System fan, kWh_{sf}

The following equation was used to calculate the annual amount of electricity consumed by the system fan in kilowatt hours per year (kWh/yr):[1]

$$kWh_{sf} = 0.746\ kW/hp \times (2.50 \times 10^{-4}) \times Q \times \Delta P_s \times \theta_s \times f_2$$

where:

hp = horsepower

2.50×10^{-4} = conversion factor with units of hp min/ft^3 in.

Q = total waste gas flow (1,497 ft^3/min)

ΔP_s = total system pressure drop (in inches of water)

θ_s = total operating time (2,000 hr/yr)

f_2 = percent of terminal operating capacity (0.50)

The system pressure drop, ΔP_s, is equal to the pressure drop through the carbon bed, ΔP_b, plus any miscellaneous pressure losses through the external ductwork and other parts of the system.[1] Assuming that these miscellaneous pressure losses amount to 1 additional inch, ΔP_s is equal to $\Delta P_b + 1$.

The pressure drop through the carbon bed, ΔP_b, is calculated as follows:

$$\Delta P_b \text{ (inches water)} = t_b(0.03679 v_b + 1.107 \times 10^{-2} v_b^2) + 1$$

where:

t_b = carbon bed thickness (11.72 ft)

v_b = superficial bed velocity (25 ft/min)

$\therefore \Delta P_b$ = 11.59 inches of water

and ΔP_s = 11.59 + 1 = 12.6 inches of water

The amount of electricity consumed by the system fan (kWh_{sf}) is then calculated as follows:

$$kWh_{sf} = \frac{0.746 \text{ kW}}{\text{hp}} \times [2.50 \times 10^{-4} \frac{\text{hp min}}{\text{ft}^3 \text{ in.}}] \times \frac{1{,}497 \text{ ft}^3}{\text{min}} \times 12.6 \text{ in.} \times 2{,}000 \text{ hr} \times 0.50$$

$$kWh_{sf} = 3{,}516 \text{ kWh}$$

2. Cooling fan, kWh_{cf}

The following equation was used to calculate the annual amount of electricity consumed by the cooling fan, kWh_{cf}:[1]

$$kWh_{cf} = \frac{0.746 \text{ kW}}{\text{hp}} \times hp_{cf} \times \theta_{cf}$$

where:

hp_{cf} = horsepower needed to run cooling fan

θ_{cf} = annual operating time of cooling fan

The horsepower needed to run the cooling fan is calculated first, using the following equation:[1]

$$hp_{cf} = \frac{2.50 \times 10^{-4} \times \Delta P_b \times m_{voc} \times M'_c}{0.4 \times \theta_D \times 60 \text{ min/hr}}$$

where:

ΔP_s = pressure drop through the system (12.59 in. of water)

m_{voc} = total mass flow rate of gasoline vapor (2,284.8 lb/hr)

M'_c = carbon requirement per bed (21,058 lb)

θ_D = desorption time (1 hour)

$\therefore$ hpcf = 6,310 hp

The operating time of the cooling fan, θ_{cf}, is calculated according to the following formula:[1]

$$\theta_{cf} = \frac{0.4 \times \theta_D \times N_A \times \theta_s \times f_2}{\theta_A}$$

where:

N_A = number of adsorbing beds (1)

θ_s = total annual terminal operating hours (2,000 hr)

f_2 = percent of terminal operating capacity (0.50)

θ_A = adsorption time (1 hour)

$\therefore \theta_{cf}$ = 400 hr/yr

The annual amount of electricity consumed by the cooling fan, kWh_{cf}, is then calculated as follows:

$$kWh_{cf} = \frac{0.746 \text{ kW}}{\text{hp}} \times 6{,}310 \text{ hp} \times 400 \text{ hr}$$

$$kWh_{cf} = 1{,}882{,}885 \text{ kWh}$$

3. Cooling water pump, kWh_{cwp}:

The annual amount of electricity consumed by the cooling water pump is calculated using the following equation:

$$kWh_{cwp} = \frac{0.746\ kWh}{hp} \times hp_{cwp} \times \theta_{cwp}$$

where:

hp_{cwp} = horsepower needed to run cooling water pump

θ_{cwp} = annual operating time of cooling water pump

The horsepower needed to run the cooling water pump, hp_{cwp} is calculated first, as follows:[1]

$$hp_{cwp} = \frac{2.52 \times 10^{-4} \times H}{\eta} \times \frac{q_{cw}}{\theta_{cwp} \times 60\ min/yr}$$

where:

H = required head (assumed 100 feet)

η = combined pump-motor efficiency (assumed 63 percent)

q_{cw} = cooling water flow, gal/yr

The cooling water flow, q_{cw}, is calculated as follows:[1]

$$q_{cw} = \frac{3.43\ gal\ water}{lb\ steam} \times \frac{3.5\ lb\ steam}{lb\ VOC} \times m_{voc} \times \theta_s \times f_2$$

where:

m_{voc} = 2,284.8 lb/hr

θ_s = 2,000 hr/yr

f_2 = percent of terminal operating capacity = 0.50

$\therefore\ q_{cw}$ = 27,429,024 gal/yr

The annual operating time of the cooling water pump, θ_{cwp}, is calculated as follows:[1]

$$\theta_{cwp} = \frac{0.6 \times \theta_D \times N_A \times \theta_s \times f_2}{\theta_A}$$

where:

$\theta D = 1$ hour

$N_A = 1$ bed

$\theta_s = 2{,}000$ hr/yr

$\theta_A = 1$ hour

$f_2 = 0.5$

$\therefore \theta cwp = 600$ hr/yr

The horsepower needed to run the cooling water pump, hp_{cwp}, is then calculated as follows:

$$hp_{cwp} = \frac{2.52 \times 10^{-4} \times 100}{0.63} \times \frac{27.43 \times 10^{6}}{600 \times 60}$$

$$hp_{cwp} = 30.48 \text{ hp}$$

Finally, the annual amount of electricity needed to run the cooling water pump, kWh_{cwp}, is calculated:

$$kWh_{cwp} = \frac{0.746 \text{ kWh}}{\text{hp}} \times 30.48 \text{ hp} \times 600 \text{ hr/yr}$$

$$= 13{,}641 \text{ kWh}$$

4. Total Electricity Consumption (TkWh)

The total annual consumption of electricity, TkWh, is equal to the sum of the electricity consumption for the system fan, bed drying/cooling fan, and the cooling water pump.

$$\therefore TkWh = kWH_{sf} + kWh_{cf} + KWh_{cwp}$$
$$= 3{,}516 + 1{,}882{,}885 + 13{,}641$$
$$= 1{,}900{,}042 \text{ kWh}$$

5. Total Annual Cost of Electricity

The total annual cost of electricity is equal to the total estimated kilowatt hours multiplied by the electricity rate ($/kWh). The same rate ($0.0472/kWh) that was used in determining annual costs for incinerator operation is used here.

$$\therefore \text{ TAC of electricity} = 1{,}900{,}042 \text{ kWh} \times \$0.0472/\text{kWh}$$
$$= \$89{,}682$$

D. Annual Steam Cost C_s):

The annual cost of steam, C_s, is calculated using the following equation from the OAQPS Control Cost Manual:[1]

$$C_s = \frac{3.5 \text{ lb steam}}{\text{lb VOC}} \times m_{voc} \times \theta_s \times p_s \times f_1 \times f_2$$

where:

m_{voc} = gasoline mass flow rate (2,284.8 lb/hr)
θ_s = operating hours per year (2,000 hr/yr)
p_s = steam price ($6/1,000 lb)
f_1 = ratio of 1987 to 1989 cost indices = 323.8/355.4
f_2 = percent of terminal operating capacity = 0.50

Note: The factors, f_1 and f_2, were added to this equation to convert from 1989 to 1987 dollars and to base the steam costs on actual (rather than maximum) throughput.

$$\therefore C_s = \frac{3.5 \text{ lb steam}}{\text{lb VOC}} \times \frac{2{,}284.8 \text{ lb}}{\text{hr}} \times \frac{2{,}000 \text{ hr}}{\text{yr}} \times \frac{\$6}{1{,}000 \text{ lb}} \times \frac{323.8}{355.4}$$

$$= \$43{,}715$$

E. Cooling Water Costs (C_{cw}):

The cost of cooling water is a function of steam usage.[1] Cooling water cost is given as:

$$C_{cw} = \frac{3.43 \text{ gal}}{\text{lb steam}} \times \frac{C_s}{p_s} \times p_{cw}$$

where:

C_s = steam cost ($43,715/yr)

p_s = steam price ($6/1,000 lb)

p_{cw} = cooling water price ($0.20/1,000 gal)

$$\therefore C_{cw} = \frac{3.43 \text{ gal}}{\text{lb steam}} \times \left(\frac{\$43,715}{\$6/1,000 \text{ lb}}\right) \times \frac{\$0.20}{1,000 \text{ gal}}$$

$$= \$4,998$$

F. <u>Carbon Replacement Cost (C_R)</u>:

The economic life of the carbon is less than that of the rest of the recovery system. The carbon replacement cost is calculated based on a 2 year life and a 10 percent interest rate.[4]

$$\text{Carbon replacement} = CRF_c[(1.08 \times C_c) + C_{cl}] \times f_1$$

CRF_c = capital recovery factor, 0.5762 for a 2 year life at 10 percent interest

1.08 = taxes and freight factor

C_c = initial cost of carbon, $76,743

C_{cl} = labor cost for carbon replacement, $0.05/lb x 42,116 lb

f_1 = ratio of 1987 to 1989 cost indices, 323.8/355.4

$$\therefore C_r = 0.5762\ [(1.08 \times \$76,743) + (\$0.05/\text{lb} \times 42,116 \text{ lb})] \times 323.8/355.4 = \$48,862$$

G. Overhead:

Overhead is taken to be 60 percent of the sum of labor and maintenance costs.

H. Property Taxes, Insurance, and Administration:

Property taxes, insurance, and administration are calculated as 4 percent of terminal capital costs.

I. Capital Recovery Charge (CRC):

The capital recovery charge, CRC, is calculated based on an interest rate of 10 percent. Piping is assumed to have a 20-year life expectancy; all other equipment is assumed to have a 10-year life. The following equation was used to calculate the capital recovery charge:[1]

$$CRC = [TCI - (1.08\ C_c + C_{cl}) - C_p] \times CRF_s + (C_p \times CRF_p)$$

where:

TCI = total terminal capital investment (does not include terminal's associated vessels) = $915,794

C_c = initial cost of carbon, $76,743

C_{cl} = labor cost for carbon replacement, $0.05/lb x 42,116 lb

C_p = cost of piping, $50,801

CRF_s = system capital recovery factor, 0.1627

CRF_p = piping capital recovery factor, 0.1175

$$\therefore CFR = [915{,}794 - ((1.08 \times 76{,}743) + (0.05 \times 42{,}116)) - 50{,}801] \times 0.1627 + (50{,}801 \times 0.1175)$$

$$= \$132{,}940$$

J. Recovery Credit (RC):

The recovery credit, RC, is based upon the control efficiency, product value, and operating hours per year as follows:[1]

$$RC = m_{voc} \times \theta_s \times p_{voc} \times E \times f_1 \times f_2$$

where:

RC = recovery credit

m_{voc} = mass inlet loading rate, 2,284.8 lb/hr

θ_s = operating hours per year, 2,000 hr/yr

p_{voc} = value of recovered product, $0.08/lb

E = adsorber control efficiency, 0.95

f_1 = ratio of 1987 to 1989 cost indices, 323.8/355.4

f_2 = percent of terminal operating capacity, 0.50

$\therefore$ RC = 2,294.8 lb/hr x 2,000 hr/yr x $0.08/lb x 0.95 x (323.8/355.4) x 0.50 = $158,205/yr

K. Vessel Retrofit Total Annual Cost (TAC):

The vessel retrofit costs are mainly for piping, instrumentation, and associated hardware. For this reason, vessel retrofits are assumed to have a 20-year life. Annual costs represent capital recovery charges plus maintenance.

Example:

The capital recovery charge and maintenance costs per vessel are shown in rounded form on Table 3-3 of the Technical Support Document.

Model 5A

Capital recovery	$19,750/vessel x 43.84 vessels =	$866,000
Maintenance	$ 9,600/vessel x 43.84 vessels =	420,000
Vessel retrofit TAC =		1,286,000

L. Emission Reduction:

The emissions are calculated as follows:

(Emission factor, lb/1,000 gal) x (throughput, bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb

Emission reduction is assumed to be 95 percent.

Example:

Model 5A (gasoline)

(3.4 lb/1,000 gal) x (16,000,000 bbl/yr) x (42 gal/bbl) x 0.000453 Mg/lb) x 0.95 = 985 Mg/yr

M. Cost Effectiveness:

Cost effectiveness is calculated by dividing the total annual cost by the emission reduction.

Example:

Model 5A (terminal only)

$$\frac{259,312 \text{ (\$/yr)}}{985 \text{ (Mg/yr)}} = 263 \text{ (\$/Mg)}$$

Model 5A (terminal and ships)

$$\frac{1,545,152 \text{ (\$/yr)}}{985 \text{ (Mg/yr)}} = 1,569 \text{ (\$/Mg)}$$

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
260	5A	89076446	3724616	701152	7859726	689375	7847949
1077	5A	46249669	3906453	513922	4230748	502144	4218970
1236	5A	20685147	1601552	402159	2064508	390381	2052730
341	5A	17648179	1275193	388882	1807167	377104	1795389
676	5A	15230723	1455029	378313	1602321	366536	1590544
690	5A	10323124	2168	356858	1186469	345081	1174692
847	5A	9304141	1132996	352404	1100126	340626	1088348
1022	5A	8662187	902288	349597	1045728	337819	1033950
599	5A	8080073	679645	347052	996402	335275	984625
752	5B	7476481	844119	295145	895988	287051	887894
490	5B	6906788	278460	292097	847157	284003	839063
1039	5B	6674286	1402	290853	827228	282759	819134
505	5B	6337037	469443	289048	798320	280954	790226
1306	5B	5970201	672815	287085	766877	278991	758783
119	5B	5965614	142078	287061	766484	278967	758390
1245	5B	5770085	151315	286015	749724	277921	741630
1010	5B	5641708	427660	285328	738720	277234	730626
1250	5B	5469227	348849	284405	723936	276311	715842
1233	5B	4958918	155066	281674	680194	273580	672100
966	5B	4498815	412341	279212	640756	271118	632662
702	5B	4269478	4604	277985	621099	269891	613005
1267	5B	4165206	875	277427	612161	269333	604067
776	5B	4041624	171898	276766	601569	268672	593475
1007	5C	3919821	261675	242363	557377	238215	553229
709	5C	3872705	813	242115	553343	237967	549195
1009	5C	3844107	436722	241965	550894	237817	546746
1531	5C	3792840	199632	241695	546504	237547	542356
921	5C	3769444	132144	241572	544501	237424	540353
141	5C	3676375	431561	241083	536533	236935	532385
680	5C	3538844	743	240360	524757	236212	520609
722	5C	3536030	124323	240345	524516	236197	520368
972	5C	3502314	290596	240168	521629	236020	517481
729	5C	3304322	17293	239127	504677	234979	500529
689	5C	3277151	117973	238985	502351	234837	498203
938	5C	3209742	322123	238630	496579	234482	492431
237	5C	3162664	81803	238383	492549	234235	488401
863	5C	2861770	155348	236801	466785	232653	462637
334	5C	2733240	54398	236126	455781	231978	451633
299	5C	2543158	160910	235126	439505	230978	435357
398	5C	2477460	520	234781	433881	230633	429733
945	5C	2464979	103256	234716	432813	230568	428665
1526	5C	2362741	118232	234178	424058	230030	419910
1222	5C	2348425	493	234103	422833	229955	418685
887	5C	2223449	96057	233446	412132	229298	407984
1296	5C	2158993	24378	233107	406613	228959	402465
1271	5C	2119369	1483	232899	403221	228751	399073
1815	5C	2077089	43679	232677	399601	228529	395453
717	5C	2025305	226418	232404	395166	228256	391018
1282	5C	1979848	416	232166	391275	228018	387127
1568	5C	1976359	60558	232147	390976	227999	386828

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
426	5C	1951118	2188	232015	388815	227867	384667
1262	5C	1911671	36990	231807	385437	227659	381289
692	5C	1880362	395	231643	382757	227495	378609
1791	5C	1871669	131869	231597	382013	227449	377865
1275	5C	1860722	611	231539	381075	227391	376927
1555	5C	1840889	94321	231435	379377	227287	375229
58	5C	1777890	84762	231104	373983	226956	369835
1008	5C	1723552	59149	230818	369330	226670	365182
1928	5C	1720883	361	230804	369102	226656	364954
1065	5C	1682802	14575	230604	365841	226456	361693
1109	5C	1676773	122121	230572	365325	226424	361177
440	5C	1637631	46563	230367	361974	226219	357826
256	5C	1612810	67819	230236	359848	226088	355700
336	5C	1600137	48043	230170	358764	226022	354616
1814	5C	1569314	138946	230008	356125	225860	351977
287	5C	1550597	326	229909	354522	225761	350374
930	5C	1481467	61970	229546	348603	225398	344455
1103	5C	1471021	11594	229491	347709	225343	343561
1229	5C	1438084	60034	229318	344889	225170	340741
1934	5C	1417808	90819	229211	343152	225063	339004
932	5C	1412400	297	229183	342690	225035	338542
1004	5C	1373168	93372	228977	339331	224829	335183
1575	5C	1356169	14583	228887	337875	224739	333727
1046	5C	1352651	126116	228869	337574	224721	333426
697	5C	1342503	762	228815	336704	224667	332556
667	5C	1283361	783	228505	331642	224357	327494
869	5C	1277038	68620	228471	331099	224323	326951
865	5C	1256884	171152	228365	329374	224217	325226
1054	5C	1220990	256	228177	326301	224029	322153
1825	5C	1215565	68668	228148	325836	224000	321688
1251	5C	1214930	12454	228145	325782	223997	321634
1087	5C	1210616	404	228122	325412	223974	321264
671	5C	1166969	2231	227893	321676	223745	317528
654	5C	1154749	242	227828	320629	223680	316481
876	5C	1138103	160750	227741	319204	223593	315056
1749	5C	1083982	148519	227457	314571	223309	310423
340	5C	1078542	51356	227428	314104	223280	309956
707	5C	1051492	221	227286	311789	223138	307641
603	5C	1042732	1427	227240	311039	223092	306891
21	5C	1031799	30845	227182	310102	223034	305954
539	5C	1031147	1893	227179	310046	223031	305898
1553	5C	1025893	3916	227151	309596	223003	305448
981	5C	997232	209	227001	307143	222853	302995
1218	5C	994044	209	226984	306870	222836	302722
913	5C	987315	136680	226948	306293	222800	302145
1124	5C	965530	31117	226834	304428	222686	300280
494	5C	963307	7573	226822	304238	222674	300090
704	5C	958324	201	226796	303811	222648	299663
631	5C	953826	21102	226772	303426	222624	299278
1030	5C	941986	132402	226710	302412	222562	298264

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
879	5C	931036	105920	226653	301475	222505	297327
990	5C	906571	100702	226524	299380	222376	295232
788	5C	905867	129358	226520	299319	222372	295171
30	5C	894331	64753	226460	298332	222312	294184
52	5C	865943	63726	226310	295901	222162	291753
188	5C	856831	2401	226263	295122	222115	290974
291	5C	832808	45538	226136	293064	221988	288916
1063	5C	827030	41682	226106	292570	221958	288422
570	5C	809891	408	226016	291102	221868	286954
1294	5C	807113	19572	226001	290864	221853	286716
1533	5C	789416	166	225908	289349	221760	285201
1002	5C	781628	81028	225867	288682	221719	284534
1881	5C	781585	164	225867	288679	221719	284531
1746	5C	780896	22272	225863	288619	221715	284471
1099	5C	779782	14269	225858	288525	221710	284377
1519	5C	779713	39298	225857	288518	221709	284370
1530	5C	776081	60392	225838	288207	221690	284059
1899	5C	735717	50200	225626	284751	221478	280603
679	5C	733511	154	225614	284562	221466	280414
643	5C	731937	154	225606	284428	221458	280280
937	5C	731655	58701	225605	284404	221457	280256
517	5C	723733	152	225563	283725	221415	279577
428	5C	715407	53659	225519	283012	221371	278864
556	5C	701880	65838	225448	281854	221300	277706
1322	5C	686317	144	225366	280521	221218	276373
242	5C	682194	33605	225345	280169	221197	276021
307	5C	669728	338	225279	279101	221131	274953
1462	5C	667925	31730	225270	278947	221122	274799
133	5C	663535	7789	225246	278571	221098	274423
351	5C	663148	5119	225244	278537	221096	274389
936	5C	649328	13820	225172	277355	221024	273207
561	5C	642852	21550	225138	276800	220990	272652
1244	5C	638160	31538	225113	276398	220965	272250
1972	5C	637588	12843	225110	276349	220962	272201
1104	5C	630274	52628	225072	275724	220924	271576
1824	5C	625648	315	225047	275327	220899	271179
274	5C	625647	56893	225047	275327	220899	271179
449	5C	611890	29972	224975	274149	220827	270001
1215	5C	603479	26834	224931	273429	220783	269281
575	5C	602568	27458	224926	273351	220778	269203
1061	5C	593545	14917	224879	272579	220731	268431
746	5C	587937	123	224849	272098	220701	267950
1085	5C	586327	171	224841	271961	220693	267813
20	5C	585442	40338	224836	271885	220688	267737
31	5C	583011	35124	224823	271676	220675	267528
1309	5C	582358	76675	224820	271621	220672	267473
1273	5C	581600	122	224816	271556	220668	267408
1018	5C	581349	29300	224814	271534	220666	267386
324	5C	580903	14902	224812	271496	220664	267348
27	5C	574727	291	224780	270968	220632	266820

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
1040	5C	571223	31983	224761	270667	220613	266519
1070	5C	565748	2577	224732	270198	220584	266050
1545	5C	558076	5696	224692	269541	220544	265393
1938	5C	554990	26242	224676	269277	220528	265129
987	5C	552099	49031	224661	269030	220513	264882
1561	5C	549185	115	224645	268780	220497	264632
694	5C	543235	4199	224614	268271	220466	264123
1249	5C	538133	113	224587	267834	220439	263686
1939	5C	533804	17260	224565	267464	220417	263316
330	5C	530726	6148	224548	267199	220400	263051
1368	5C	509935	21406	224439	265420	220291	261272
407	5C	507102	4665	224424	265177	220276	261029
950	5C	500876	22391	224391	264644	220243	260496
513	5C	491649	19036	224343	263854	220195	259706
1020	5C	487949	102	224324	263538	220176	259390
1821	5C	487557	66807	224321	263503	220173	259355
1762	5C	483870	1550	224302	263188	220154	259040
724	5C	475424	63463	224258	262465	220110	258317
295	5C	474821	5559	224255	262414	220107	258266
1817	5C	474645	56687	224254	262399	220106	258251
239	5C	469587	18145	224227	261965	220079	257817
1164	5C	465777	19551	224207	261639	220059	257491
28	5C	461181	35660	224183	261246	220035	257098
1050	5C	460299	97	224178	261170	220030	257022
1216	5C	459877	23526	224176	261134	220028	256986
34	5C	459135	231	224172	261070	220024	256922
164	5C	455417	5815	224153	260752	220005	256604
1574	5C	451678	6146	224133	260432	219985	256284
377	5C	441416	9717	224079	259553	219931	255405
1231	5C	440271	3426	224073	259455	219925	255307
747	5C	435274	2278	224047	259028	219899	254880
530	5C	425194	89	223994	258164	219846	254016
125	5C	422005	217	223977	257891	219829	253743
1254	5C	418473	6103	223958	257588	219810	253440
1328	5C	414546	87	223938	257253	219790	253105
771	5C	414176	58891	223936	257221	219788	253073
509	5C	408432	86	223906	256729	219758	252581
606	5C	403320	48257	223879	256292	219731	252144
1032	5C	401778	84	223871	256160	219723	252012
1160	5C	398618	13394	223854	255889	219706	251741
446	5C	397040	158	223846	255754	219698	251606
908	5C	388655	20056	223802	255036	219654	250888
1319	5C	388295	13047	223800	255005	219652	250857
1891	5C	387016	195	223793	254895	219645	250747
1491	5C	386154	195	223788	254821	219640	250673
1811	5C	384780	22856	223781	254704	219633	250556
914	5C	384546	45669	223780	254684	219632	250536
1011	5C	381428	19224	223764	254417	219616	250269
25	5C	375486	17015	223732	253908	219584	249760
43	5C	372132	6590	223715	253621	219567	249473

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1415	5C	370959	36036	223709	253521	219561	249373
202	5C	369130	7355	223699	253364	219551	249216
995	5C	368989	46131	223698	253352	219550	249204
1697	5C	364170	184	223673	252939	219525	248791
216	5C	361557	44469	223659	252715	219511	248567
1093	5C	360508	76	223654	252626	219506	248478
1058	5C	359923	76	223651	252576	219503	248428
848	5C	357745	49840	223639	252389	219491	248241
626	5C	353556	14461	223617	252030	219469	247882
1616	5C	351046	177	223604	251816	219456	247668
240	5C	349178	176	223594	251655	219446	247507
964	5C	346730	73	223581	251446	219433	247298
1650	5C	342444	72	223559	251079	219411	246931
1064	5C	341140	4267	223552	250968	219404	246820
543	5C	338146	71	223536	250711	219388	246563
464	5C	330417	167	223495	250049	219347	245901
442	5C	320397	10692	223443	249192	219295	245044
393	5C	318976	8908	223435	249069	219287	244921
726	5C	318584	22834	223433	249036	219285	244888
425	5C	317327	22691	223427	248929	219279	244781
26	5C	316934	4952	223425	248895	219277	244747
507	5C	314930	159	223414	248723	219266	244575
734	5C	307788	15512	223377	248112	219229	243964
262	5C	307644	20505	223376	248100	219228	243952
1083	5C	302514	43199	223349	247660	219201	243512
1150	5C	297666	11459	223323	247245	219175	243097
255	5C	294551	78	223307	246978	219159	242830
1179	5C	289070	8885	223278	246509	219130	242361
835	5C	287454	12061	223270	246371	219122	242223
629	5C	287011	145	223267	246332	219119	242184
1133	5C	286349	60	223264	246276	219116	242128
953	5C	283303	11439	223248	246015	219100	241867
978	5C	282617	14522	223244	245956	219096	241808
1751	5C	276844	58	223214	245462	219066	241314
1482	5C	272647	24947	223192	245103	219044	240955
308	5C	270850	134	223182	244949	219034	240801
471	5C	267815	135	223166	244689	219018	240541
1098	5C	265734	134	223155	244511	219007	240363
1227	5C	262692	28748	223140	244251	218992	240103
1569	5C	259266	552	223121	243957	218973	239809
1571	5C	257437	3310	223112	243801	218964	239653
1743	5C	255378	54	223101	243624	218953	239476
1182	5C	251406	1795	223080	243284	218932	239136
1211	5C	251267	6967	223079	243272	218931	239124
422	5C	250816	53	223077	243234	218929	239086
1122	5C	247479	52	223060	242948	218912	238800
1120	5C	247101	21346	223058	242916	218910	238768
443	5C	244368	7890	223043	242681	218895	238533
904	5C	242311	19618	223032	242505	218884	238357
1900	5C	241755	19359	223029	242457	218881	238309

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1056	5C	237183	50	223005	242066	218857	237918
1200	5C	236306	7684	223001	241992	218853	237844
33	5C	235726	29819	222998	241942	218850	237794
1430	5C	235583	8234	222997	241929	218849	237781
1778	5C	230210	48	222969	241470	218821	237322
1207	5C	224726	8542	222940	241000	218792	236852
1276	5C	221748	5615	222924	240745	218776	236597
632	5C	214912	948	222888	240159	218740	236011
1476	5C	214865	45	222888	240155	218740	236007
158	5C	213221	25836	222879	240014	218731	235866
1145	5C	212584	452	222876	239960	218728	235812
743	5C	211222	103	222869	239844	218721	235696
409	5C	210694	44	222866	239798	218718	235650
1745	5C	210057	44	222863	239744	218715	235596
996	5C	208961	11767	222857	239650	218709	235502
406	5C	207393	82	222849	239516	218701	235368
1529	5C	207291	10447	222848	239507	218700	235359
403	5C	207262	96	222848	239504	218700	235356
1820	5C	204273	43	222832	239248	218684	235100
946	5C	202470	43	222823	239094	218675	234946
977	5C	200483	1185	222813	238925	218665	234777
53	5C	200388	16766	222812	238916	218664	234768
992	5C	199302	100	222806	238823	218658	234675
920	5C	193050	58	222773	238287	218625	234139
1892	5C	188933	95	222752	237935	218604	233787
1816	5C	187204	7926	222743	237788	218595	233640
521	5C	187036	39	222742	237773	218594	233625
951	5C	186402	11455	222738	237718	218590	233570
63	5C	185223	93	222732	237617	218584	233469
430	5C	181533	9149	222713	237302	218565	233154
332	5C	179757	91	222704	237150	218556	233002
1410	5C	175824	5149	222683	236813	218535	232665
712	5C	175181	37	222680	236758	218532	232610
57	5C	174623	88	222677	236710	218529	232562
1286	5C	172353	1931	222665	236516	218517	232368
1283	5C	171251	36	222659	236421	218511	232273
410	5C	169736	36	222651	236292	218503	232144
759	5C	167078	5383	222637	236064	218489	231916
60	5C	166837	84	222636	236044	218488	231896
1066	5C	166448	10683	222634	236010	218486	231862
1763	5C	165852	7784	222630	235959	218482	231811
993	5C	163571	82	222618	235763	218470	231615
488	5C	160437	5485	222602	235495	218454	231347
595	5C	160406	34	222602	235493	218454	231345
2017	5C	158001	33	222589	235287	218441	231139
485	5C	157955	33	222589	235283	218441	231135
1197	5C	157229	7924	222585	235221	218437	231073
706	5C	157003	33	222584	235201	218436	231053
6	5C	155154	78	222574	235043	218426	230895
318	5C	153613	18453	222566	234911	218418	230763

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1112	5C	151387	7630	222554	234720	218406	230572
1583	5C	150952	32	222552	234683	218404	230535
1175	5C	149842	7697	222546	234588	218398	230440
1511	5C	148667	31	222540	234488	218392	230340
1052	5C	146712	20951	222530	234320	218382	230172
1866	5C	146026	31	222526	234261	218378	230113
1422	5C	144692	7292	222519	234147	218371	229999
1543	5C	143984	1581	222516	234087	218368	229939
1331	5C	142470	7180	222508	233958	218360	229810
1110	5C	140368	29	222497	233778	218349	229630
329	5C	139764	6579	222493	233725	218345	229577
941	5C	136127	1741	222474	233414	218326	229266
916	5C	135947	19413	222473	233398	218325	229250
1019	5C	135149	28	222469	233330	218321	229182
1075	5C	135010	28	222468	233318	218320	229170
61	5C	134432	68	222465	233269	218317	229121
648	5C	132127	28	222453	233071	218305	228923
35	5C	131568	6631	222450	233023	218302	228875
1888	5C	129622	65	222440	232857	218292	228709
958	5C	129620	3698	222440	232857	218292	228709
484	5C	128413	12973	222434	232754	218286	228606
685	5C	126254	27	222422	232568	218274	228420
750	5C	125620	3805	222419	232514	218271	228366
439	5C	125483	14426	222418	232502	218270	228354
1119	5C	124444	26	222413	232414	218265	228266
710	5C	124241	26	222412	232397	218264	228249
559	5C	123030	62	222405	232292	218257	228144
1367	5C	122698	62	222404	232265	218256	228117
2041	5C	120851	15718	222394	232106	218246	227958
469	5C	119213	7442	222385	231965	218237	227817
441	5C	119213	7442	222385	231965	218237	227817
1073	5C	118921	25	222384	231941	218236	227793
1095	5C	117661	25	222377	231833	218229	227685
1926	5C	117073	5900	222374	231782	218226	227634
1459	5C	113986	5483	222358	231518	218210	227370
415	5C	113539	7088	222356	231480	218208	227332
1049	5C	113536	24	222355	231479	218207	227331
1234	5C	112508	6487	222350	231392	218202	227244
1111	5C	112204	1343	222348	231365	218200	227217
533	5C	111363	24	222344	231294	218196	227146
1015	5C	110965	5593	222342	231260	218194	227112
719	5C	110730	23	222341	231240	218193	227092
739	5C	110063	866	222337	231182	218189	227034
944	5C	107847	7039	222326	230993	218178	226845
413	5C	107209	5403	222322	230938	218174	226790
909	5C	106582	3663	222319	230884	218171	226736
1096	5C	106495	54	222318	230876	218170	226728
1728	5C	106302	2660	222317	230860	218169	226712
479	5C	105804	53	222315	230818	218167	226670
487	5C	104793	3565	222310	230732	218162	226584

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824	5C	103665	4341	222304	230635	218156	226487
725	5C	103291	14750	222302	230603	218154	226455
591	5C	103191	3997	222301	230594	218153	226446
1612	5C	103024	52	222300	230579	218152	226431
963	5C	101740	21	222293	230469	218145	226321
282	5C	101173	51	222291	230422	218143	226274
1887	5C	99714	21	222283	230296	218135	226148
1537	5C	98684	21	222277	230208	218129	226060
594	5C	98321	21	222276	230178	218128	226030
444	5C	97294	11270	222270	230089	218122	225941
1114	5C	95044	629	222258	229896	218110	225748
745	5C	93643	47	222251	229777	218103	225629
1041	5C	93391	10564	222250	229755	218102	225607
1787	5C	92970	3829	222247	229718	218099	225570
266	5C	92159	19	222243	229649	218095	225501
15	5C	91642	48	222240	229605	218092	225457
389	5C	89080	755	222227	229386	218079	225238
1126	5C	88927	19	222226	229373	218078	225225
1770	5C	88546	19	222224	229340	218076	225192
11	5C	88499	7974	222224	229336	218076	225188
1884	5C	87802	44	222220	229276	218072	225128
48	5C	87324	44	222218	229236	218070	225088
306	5C	86844	629	222215	229194	218067	225046
1837	5C	86815	18	222215	229192	218067	225044
221	5C	85471	44	222208	229077	218060	224929
948	5C	85435	2547	222208	229074	218060	224926
1180	5C	85011	978	222206	229038	218058	224890
159	5C	83920	6524	222200	228944	218052	224796
1852	5C	83223	8149	222196	228884	218048	224736
1105	5C	82912	36	222195	228858	218047	224710
1840	5C	82576	17	222193	228829	218045	224681
162	5C	82557	42	222193	228828	218045	224680
577	5C	82088	11722	222190	228787	218042	224639
355	5C	82019	17	222190	228781	218042	224633
1831	5C	81752	11674	222188	228758	218040	224610
1927	5C	81619	17	222188	228747	218040	224599
1417	5C	81409	4103	222187	228729	218039	224581
185	5C	80954	41	222184	228690	218036	224542
942	5C	80686	4067	222183	228667	218035	224519
1577	5C	79368	40	222176	228554	218028	224406
621	5C	79204	36	222175	228540	218027	224392
86	5C	78760	7411	222173	228502	218025	224354
67	5C	77910	39	222168	228429	218020	224281
627	5C	77214	1498	222165	228370	218017	224222
1910	5C	77143	16	222164	228364	218016	224216
217	5C	76656	39	222162	228322	218014	224174
2030	5C	76161	38	222159	228280	218011	224132
1832	5C	76019	16	222158	228267	218010	224119
276	5C	75503	590	222156	228224	218008	224076
1330	5C	74874	3774	222152	228169	218004	224021

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1252	5C	74147	1410	222148	228107	218000	223959
1985	5C	73148	1198	222143	228021	217995	223873
55	5C	72622	37	222140	227976	217992	223828
1478	5C	72621	3641	222140	227976	217992	223828
73	5C	71627	10228	222135	227891	217987	223743
1084	5C	71048	10146	222132	227842	217984	223694
1653	5C	70175	35	222128	227768	217980	223620
1878	5C	69834	929	222126	227738	217978	223590
1401	5C	69686	3512	222125	227725	217977	223577
957	5C	69562	7065	222124	227714	217976	223566
1687	5C	68679	14	222120	227639	217972	223491
1213	5C	67917	14	222116	227574	217968	223426
76	5C	67642	34	222114	227550	217966	223402
13	5C	67122	34	222112	227506	217964	223358
1688	5C	66687	34	222109	227468	217961	223320
859	5C	66090	33	222106	227417	217958	223269
1917	5C	65965	14	222105	227406	217957	223258
1212	5C	65825	2957	222105	227395	217957	223247
1037	5C	65280	9322	222102	227348	217954	223200
1510	5C	65079	4180	222101	227331	217953	223183
565	5C	64837	3268	222100	227311	217952	223163
548	5C	64794	33	222099	227306	217951	223158
416	5C	64104	3231	222096	227248	217948	223100
974	5C	63523	32	222093	227198	217945	223050
51	5C	63225	32	222091	227172	217943	223024
1992	5C	63088	32	222090	227160	217942	223012
1115	5C	62579	1669	222088	227117	217940	222969
705	5C	62339	2940	222086	227096	217938	222948
1092	5C	62222	13	222086	227086	217938	222938
427	5C	61905	13	222084	227059	217936	222911
960	5C	61623	8800	222083	227035	217935	222887
601	5C	61232	13	222081	227002	217933	222854
1867	5C	60953	13	222079	226977	217931	222829
1563	5C	60740	4440	222078	226959	217930	222811
1158	5C	59840	1228	222073	226882	217925	222734
2027	5C	59556	13	222072	226858	217924	222710
492	5C	59511	12	222072	226855	217924	222707
473	5C	59502	5092	222071	226853	217923	222705
1793	5C	59379	30	222071	226843	217923	222695
633	5C	58867	30	222068	226799	217920	222651
1017	5C	58395	7618	222066	226759	217918	222611
1868	5C	58292	12	222065	226750	217917	222602
1094	5C	58172	12	222064	226739	217916	222591
1284	5C	57818	29	222063	226710	217915	222562
397	5C	57755	12	222062	226703	217914	222555
547	5C	57349	8189	222060	226669	217912	222521
1203	5C	57089	2086	222059	226647	217911	222499
715	5C	56856	362	222058	226627	217910	222479
970	5C	56438	2552	222055	226591	217907	222443
478	5C	56391	2138	222055	226587	217907	222439

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1973	5C	56264	1770	222054	226576	217906	222428
1535	5C	55778	12	222052	226535	217904	222387
1813	5C	54626	2753	222046	226436	217898	222288
1869	5C	53196	27	222038	226313	217890	222165
1986	5C	52855	1293	222037	226285	217889	222137
186	5C	52412	26	222034	226246	217886	222098
1839	5C	51954	11	222032	226207	217884	222059
305	5C	51655	28	222030	226181	217882	222033
106	5C	51413	1727	222029	226161	217881	222013
110	5C	51343	26	222029	226155	217881	222007
961	5C	50993	1386	222027	226125	217879	221977
1230	5C	50438	7203	222024	226077	217876	221929
1421	5C	50075	25	222022	226046	217874	221898
672	5C	49160	10	222017	225968	217869	221820
379	5C	49047	1454	222017	225959	217869	221811
466	5C	48813	25	222015	225938	217867	221790
2002	5C	48723	3976	222015	225931	217867	221783
1497	5C	48404	4386	222013	225903	217865	221755
1003	5C	47755	24	222010	225848	217862	221700
1012	5C	47619	10	222009	225836	217861	221688
1546	5C	46742	839	222004	225760	217856	221612
1525	5C	46488	2343	222003	225739	217855	221591
1029	5C	46476	23	222003	225738	217855	221590
994	5C	45741	1537	221999	225675	217851	221527
1036	5C	45714	10	221999	225673	217851	221525
1071	5C	44032	9	221990	225529	217842	221381
1564	5C	43625	314	221988	225494	217840	221346
1082	5C	43538	1268	221988	225487	217840	221339
72	5C	43482	6209	221987	225481	217839	221333
1176	5C	42581	1388	221983	225405	217835	221257
1658	5C	42366	21	221981	225386	217833	221238
1773	5C	42197	9	221981	225372	217833	221224
325	5C	41784	9	221978	225336	217830	221188
971	5C	41723	2932	221978	225331	217830	221183
693	5C	41505	1395	221977	225313	217829	221165
609	5C	41384	8	221976	225302	217828	221154
1349	5C	40916	21	221974	225262	217826	221114
32	5C	40585	22	221972	225234	217824	221086
1038	5C	40526	5787	221972	225229	217824	221081
227	5C	40015	5714	221969	225185	217821	221037
1780	5C	39969	2014	221969	225181	217821	221033
1620	5C	39873	8	221968	225172	217820	221024
525	5C	39543	5647	221967	225145	217819	220997
1635	5C	39365	8	221966	225130	217818	220982
1678	5C	38787	8	221963	225080	217815	220932
437	5C	38733	20	221962	225075	217814	220927
331	5C	38708	20	221962	225073	217814	220925
309	5C	38692	8	221962	225071	217814	220923
1592	5C	38377	5480	221960	225044	217812	220896
1107	5C	38273	19	221960	225036	217812	220888

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
1978	5C	38167	331	221959	225026	217811	220878
219	5C	37916	593	221958	225005	217810	220857
1102	5C	37805	2670	221957	224995	217809	220847
1060	5C	37796	1270	221957	224994	217809	220846
1679	5C	37721	8	221957	224988	217809	220840
1559	5C	37309	19	221955	224953	217807	220805
293	5C	37272	5322	221955	224950	217807	220802
1578	5C	37208	13	221954	224944	217806	220796
1068	5C	37079	8	221954	224934	217806	220786
551	5C	36985	19	221953	224925	217805	220777
1456	5C	36874	892	221953	224916	217805	220768
954	5C	36698	1217	221952	224901	217804	220753
967	5C	36544	3000	221951	224888	217803	220740
1088	5C	36511	116	221951	224885	217803	220737
1089	5C	36501	3271	221951	224884	217803	220736
1794	5C	36358	8	221950	224872	217802	220724
328	5C	36269	18	221949	224864	217801	220716
395	5C	36072	18	221948	224847	217800	220699
1784	5C	35650	5091	221946	224811	217798	220663
986	5C	35594	7	221946	224806	217798	220658
1534	5C	35375	5052	221945	224788	217797	220640
1062	5C	35246	1184	221944	224777	217796	220629
209	5C	35239	18	221944	224776	217796	220628
278	5C	35106	19	221943	224764	217795	220616
38	5C	34998	18	221943	224756	217795	220608
720	5C	34886	1365	221942	224746	217794	220598
1518	5C	34833	2899	221942	224741	217794	220593
1573	5C	34373	985	221939	224701	217791	220553
223	5C	34278	1728	221939	224694	217791	220546
1879	5C	34070	7	221938	224676	217790	220528
1838	5C	33949	17	221937	224665	217789	220517
1194	5C	33796	7	221936	224652	217788	220504
143	5C	33737	4818	221936	224647	217788	220499
1473	5C	33547	11	221935	224631	217787	220483
68	5C	33411	1684	221934	224619	217786	220471
2033	5C	33368	29	221934	224616	217786	220468
1680	5C	33359	7	221934	224615	217786	220467
638	5C	33024	568	221932	224586	217784	220438
1767	5C	33003	7	221932	224584	217784	220436
1043	5C	32843	398	221931	224570	217783	220422
748	5C	32749	7	221931	224563	217783	220415
1601	5C	32724	7	221931	224561	217783	220413
1239	5C	32585	1095	221930	224549	217782	220401
267	5C	32571	4651	221930	224548	217782	220400
62	5C	32406	16	221929	224533	217781	220385
316	5C	32175	1796	221928	224514	217780	220366
623	5C	32044	2821	221927	224502	217779	220354
660	5C	31905	7	221926	224490	217778	220342
197	5C	31800	16	221926	224482	217778	220334
1663	5C	31797	1068	221926	224481	217778	220333

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
238	5C	31519	16	221924	224457	217776	220309
1461	5C	31493	16	221924	224455	217776	220307
414	5C	31150	1570	221922	224425	217774	220277
537	5C	31007	16	221922	224414	217774	220266
554	5C	30825	6	221921	224398	217773	220250
1118	5C	30700	15	221920	224387	217772	220239
968	5C	30635	1872	221920	224382	217772	220234
91	5C	30504	15	221919	224370	217771	220222
1014	5C	30476	6	221919	224368	217771	220220
1201	5C	30257	1525	221918	224350	217770	220202
1520	5C	30120	1518	221917	224338	217769	220190
121	5C	30110	4300	221917	224337	217769	220189
1783	5C	30089	6	221917	224335	217769	220187
163	5C	29881	87	221916	224317	217768	220169
1357	5C	29851	1227	221916	224315	217768	220167
1528	5C	29666	1495	221915	224299	217767	220151
96	5C	29646	4233	221915	224297	217767	220149
959	5C	29646	4233	221915	224297	217767	220149
404	5C	29390	6	221913	224275	217765	220127
1172	5C	29389	521	221913	224275	217765	220127
335	5C	29370	15	221913	224273	217765	220125
1523	5C	29297	1140	221913	224267	217765	220119
348	5C	29234	4175	221912	224261	217764	220113
1108	5C	29073	2210	221912	224248	217764	220100
1977	5C	28798	15	221910	224224	217762	220076
192	5C	28764	1785	221910	224222	217762	220074
1781	5C	28734	1448	221910	224219	217762	220071
1033	5C	28705	6	221910	224217	217762	220069
1779	5C	28672	1445	221909	224213	217761	220065
1106	5C	28387	1167	221908	224189	217760	220041
1321	5C	28114	4015	221906	224165	217758	220017
1918	5C	26837	6	221900	224057	217752	219909
1810	5C	26727	2708	221899	224047	217751	219899
955	5C	26658	13	221899	224041	217751	219893
402	5C	26396	1330	221897	224018	217749	219870
956	5C	26175	522	221896	224000	217748	219852
191	5C	26112	13	221896	223994	217748	219846
1034	5C	26000	2131	221895	223984	217747	219836
243	5C	25907	13	221895	223977	217747	219829
1162	5C	25841	2053	221895	223972	217747	219824
991	5C	25772	583	221894	223965	217746	219817
127	5C	25646	3662	221894	223955	217746	219807
212	5C	25583	13	221893	223949	217745	219801
270	5C	25250	3606	221891	223920	217743	219772
1300	5C	25234	3603	221891	223919	217743	219771
566	5C	25214	1271	221891	223917	217743	219769
1845	5C	25191	13	221891	223915	217743	219767
1570	5C	25170	479	221891	223914	217743	219766
252	5C	24709	3528	221889	223875	217741	219727
157	5C	24709	3528	221889	223875	217741	219727

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114	5C	24628	12	221888	223867	217740	219719
87	5C	24437	13	221887	223851	217739	219703
1324	5C	24425	1324	221887	223850	217739	219702
602	5C	24017	456	221885	223815	217737	219667
965	5C	23588	12	221883	223779	217735	219631
1362	5C	23178	12	221881	223744	217733	219596
506	5C	22857	3264	221879	223716	217731	219568
1031	5C	22857	3264	221879	223716	217731	219568
1042	5C	22857	3264	221879	223716	217731	219568
1307	5C	22857	3264	221879	223716	217731	219568
1804	5C	22666	5	221878	223700	217730	219552
980	5C	22457	5	221877	223682	217729	219534
597	5C	22438	5	221877	223680	217729	219532
2015	5C	22210	5	221875	223660	217727	219512
118	5C	22201	12	221875	223659	217727	219511
1485	5C	22000	5	221874	223642	217726	219494
1955	5C	21966	230	221874	223639	217726	219491
1789	5C	21941	520	221874	223637	217726	219489
592	5C	21702	4	221873	223617	217725	219469
1522	5C	21612	1089	221872	223609	217724	219461
1457	5C	21340	1076	221871	223586	217723	219438
1557	5C	21310	2386	221871	223584	217723	219436
497	5C	21232	4	221870	223576	217722	219428
1475	5C	21084	4	221870	223564	217722	219416
1524	5C	21058	1061	221869	223561	217721	219413
1318	5C	20783	698	221868	223538	217720	219390
661	5C	20660	4	221867	223527	217719	219379
2040	5C	20535	10	221867	223517	217719	219369
1987	5C	20375	252	221866	223503	217718	219355
1997	5C	20121	10	221864	223481	217716	219333
1132	5C	19886	4	221863	223461	217715	219313
639	5C	19841	4	221863	223458	217715	219310
303	5C	19793	10	221863	223454	217715	219306
75	5C	19764	2822	221863	223451	217715	219303
107	5C	19764	2822	221863	223451	217715	219303
245	5C	19761	2551	221863	223451	217715	219303
301	5C	19642	2805	221862	223441	217714	219293
730	5C	19622	10	221862	223439	217714	219291
924	5C	19608	659	221862	223438	217714	219290
1310	5C	19589	2797	221862	223436	217714	219288
1121	5C	19522	4	221861	223430	217713	219282
1487	5C	19247	10	221860	223407	217712	219259
1130	5C	19048	4	221859	223390	217711	219242
740	5C	19010	4	221859	223387	217711	219239
1051	5C	18914	4	221858	223378	217710	219230
1006	5C	18846	9	221858	223373	217710	219225
1134	5C	18824	949	221858	223371	217710	219223
9	5C	18795	9	221857	223367	217709	219219
1470	5C	18736	9	221857	223363	217709	219215
526	5C	18715	943	221857	223361	217709	219213

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1844	5C	18434	10	221856	223337	217708	219189
1521	5C	18198	917	221854	223316	217706	219168
564	5C	17900	9	221853	223292	217705	219144
229	5C	17790	2540	221852	223282	217704	219134
540	5C	17775	2538	221852	223280	217704	219132
536	5C	17718	551	221852	223276	217704	219128
695	5C	17714	4	221852	223276	217704	219128
721	5C	17695	4	221852	223274	217704	219126
338	5C	17693	892	221852	223274	217704	219126
115	5C	17474	10	221851	223255	217703	219107
616	5C	17470	880	221851	223255	217703	219107
211	5C	17455	2493	221850	223253	217702	219105
80	5C	17326	2474	221850	223242	217702	219094
976	5C	17260	9	221849	223236	217701	219088
1999	5C	17049	494	221848	223218	217700	219070
933	5C	16800	2399	221847	223197	217699	219049
1224	5C	16692	4	221846	223187	217698	219039
1198	5C	16681	838	221846	223187	217698	219039
1235	5C	16422	417	221845	223165	217697	219017
701	5C	16152	2307	221844	223142	217696	218994
1603	5C	16152	3	221844	223142	217696	218994
2010	5C	16133	3	221844	223141	217696	218993
177	5C	16044	3	221843	223132	217695	218984
612	5C	16025	3	221843	223131	217695	218983
1873	5C	15998	197	221843	223129	217695	218981
741	5C	15878	800	221842	223118	217694	218970
1843	5C	15810	2258	221842	223113	217694	218965
434	5C	15750	1862	221841	223107	217693	218959
210	5C	15555	8	221840	223090	217692	218942
1274	5C	15232	3	221839	223063	217691	218915
675	5C	15054	3	221838	223048	217690	218900
1536	5C	15054	3	221838	223048	217690	218900
1871	5C	15044	3	221838	223047	217690	218899
1076	5C	14838	7	221837	223029	217689	218881
297	5C	14719	7	221836	223019	217688	218871
1001	5C	14692	3	221836	223017	217688	218869
1045	5C	14510	731	221835	223001	217687	218853
1556	5C	14400	2056	221834	222991	217686	218843
969	5C	13954	703	221832	222953	217684	218805
928	5C	13905	3	221832	222949	217684	218801
756	5C	13669	1952	221831	222930	217683	218782
248	5C	13184	7	221828	222888	217680	218740
1127	5C	12996	3	221827	222871	217679	218723
696	5C	12760	124	221826	222851	217678	218703
1258	5C	12691	640	221825	222845	217677	218697
1990	5C	12613	168	221825	222839	217677	218691
1299	5C	12287	413	221823	222810	217675	218662
998	5C	12190	1741	221823	222803	217675	218655
600	5C	12169	6	221823	222801	217675	218653
727	5C	11943	3	221821	222781	217673	218633

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1116	5C	11939	6	221821	222780	217673	218632
984	5C	11939	6	221821	222780	217673	218632
997	5C	11939	6	221821	222780	217673	218632
1117	5C	11939	6	221821	222780	217673	218632
1988	5C	11913	6	221821	222778	217673	218630
619	5C	11908	600	221821	222778	217673	218630
304	5C	11839	597	221821	222772	217673	218624
1463	5C	11819	6	221821	222771	217673	218623
1260	5C	11721	2	221820	222762	217672	218614
1785	5C	11651	2	221820	222756	217672	218608
74	5C	11568	2	221820	222750	217672	218602
1268	5C	11567	389	221820	222750	217672	218602
16	5C	11436	6	221819	222738	217671	218590
983	5C	11429	1632	221819	222737	217671	218589
277	5C	11210	6	221818	222719	217670	218571
1101	5C	11185	1597	221817	222716	217669	218568
1206	5C	11055	1579	221817	222705	217669	218557
1412	5C	11010	555	221817	222702	217669	218554
1329	5C	11010	555	221817	222702	217669	218554
1560	5C	10965	2	221816	222697	217668	218549
1558	5C	10965	2	221816	222697	217668	218549
1940	5C	10871	335	221816	222690	217668	218542
1906	5C	10845	2	221816	222688	217668	218540
1363	5C	10844	2	221816	222687	217668	218539
1411	5C	10753	361	221815	222679	217667	218531
1458	5C	10753	361	221815	222679	217667	218531
973	5C	10667	1523	221815	222672	217667	218524
1035	5C	10667	1523	221815	222672	217667	218524
624	5C	10623	3	221815	222669	217667	218521
1210	5C	10540	531	221814	222661	217666	218513
742	5C	10444	2	221814	222653	217666	218505
919	5C	10421	5	221813	222650	217665	218502
2021	5C	10421	5	221813	222650	217665	218502
2000	5C	10233	5	221812	222634	217664	218486
1161	5C	10122	510	221812	222625	217664	218477
1173	5C	10086	508	221812	222623	217664	218475
1059	5C	10086	508	221812	222623	217664	218475
84	5C	10067	5	221812	222621	217664	218473
1013	5C	10038	2	221811	222618	217663	218470
1782	5C	9972	164	221811	222612	217663	218464
1192	5C	9950	1421	221811	222611	217663	218463
1527	5C	9927	500	221811	222609	217663	218461
1342	5C	9909	5	221811	222607	217663	218459
2004	5C	9886	480	221811	222605	217663	218457
1416	5C	9862	497	221811	222604	217663	218456
1326	5C	9822	2	221810	222599	217662	218451
296	5C	9770	328	221810	222595	217662	218447
662	5C	9759	2	221810	222594	217662	218446
1346	5C	9740	2	221810	222593	217662	218445
615	5C	9632	485	221809	222583	217661	218435

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1255	5C	9568	2	221809	222578	217661	218430
1026	5C	9531	2	221809	222575	217661	218427
123	5C	9387	1340	221808	222562	217660	218414
999	5C	9381	5	221808	222562	217660	218414
1226	5C	9371	1338	221808	222561	217660	218413
1021	5C	9290	2	221808	222555	217660	218407
989	5C	9287	5	221808	222554	217660	218406
1544	5C	9029	2	221806	222532	217658	218384
386	5C	9005	5	221806	222530	217658	218382
1550	5C	8946	2	221806	222525	217658	218377
698	5C	8889	2	221805	222519	217657	218371
650	5C	8889	2	221805	222519	217657	218371
630	5C	8889	2	221805	222519	217657	218371
1055	5C	8889	2	221805	222519	217657	218371
1074	5C	8889	2	221805	222519	217657	218371
1549	5C	8889	2	221805	222519	217657	218371
1565	5C	8889	2	221805	222519	217657	218371
1027	5C	8889	2	221805	222519	217657	218371
1067	5C	8889	2	221805	222519	217657	218371
979	5C	8846	1263	221805	222516	217657	218368
1905	5C	8747	3	221805	222508	217657	218360
1053	5C	8610	1229	221804	222496	217656	218348
1440	5C	8584	2	221804	222494	217656	218346
511	5C	8578	2	221804	222493	217656	218345
1562	5C	8528	4	221804	222489	217656	218341
1123	5C	8481	2	221803	222485	217655	218337
1605	5C	8463	2	221803	222483	217655	218335
985	5C	8432	2	221803	222481	217655	218333
611	5C	8400	2	221803	222478	217655	218330
1272	5C	8292	2	221802	222468	217654	218320
590	5C	8286	2	221802	222468	217654	218320
1819	5C	7939	4	221800	222438	217652	218290
81	5C	7924	1132	221800	222437	217652	218289
1189	5C	7917	2	221800	222436	217652	218288
501	5C	7886	2	221800	222434	217652	218286
2019	5C	7854	197	221800	222431	217652	218283
1243	5C	7642	280	221799	222413	217651	218265
503	5C	7638	2	221799	222413	217651	218265
1790	5C	7549	2	221798	222405	217650	218257
934	5C	7535	253	221798	222404	217650	218256
357	5C	7406	1058	221798	222393	217650	218245
636	5C	7397	2	221798	222392	217650	218244
99	5C	7385	4	221798	222391	217650	218243
1100	5C	7245	4	221797	222379	217649	218231
1028	5C	7204	363	221797	222376	217649	218228
889	5C	7095	4	221796	222366	217648	218218
1265	5C	6997	1	221795	222357	217647	218209
2001	5C	6822	3	221795	222343	217647	218195
878	5C	6819	1	221795	222343	217647	218195
649	5C	6737	3	221794	222335	217646	218187

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
2026	5C	6660	3	221794	222329	217646	218181
1566	5C	6614	222	221793	222325	217645	218177
49	5C	6350	549	221792	222302	217644	218154
1865	5C	6349	1	221792	222302	217644	218154
605	5C	6343	1	221792	222302	217644	218154
1828	5C	6302	3	221792	222298	217644	218150
618	5C	6275	316	221792	222296	217644	218148
44	5C	6137	189	221791	222284	217643	218136
731	5C	6123	309	221791	222283	217643	218135
47	5C	5979	332	221790	222270	217642	218122
2008	5C	5915	88	221790	222265	217642	218117
1769	5C	5708	1	221789	222248	217641	218100
1998	5C	5681	276	221789	222246	217641	218098
2025	5C	5659	38	221788	222243	217640	218095
1334	5C	5603	3	221788	222238	217640	218090
940	5C	5441	1	221787	222224	217639	218076
1989	5C	5297	526	221787	222213	217639	218065
1196	5C	5276	1	221786	222210	217638	218062
320	5C	5257	177	221786	222208	217638	218060
2035	5C	5031	3	221785	222189	217637	218041
419	5C	5014	3	221785	222188	217637	218040
369	5C	4724	2	221784	222164	217636	218016
925	5C	4699	1	221783	222161	217635	218013
635	5C	4690	2	221783	222160	217635	218012
642	5C	4648	1	221783	222157	217635	218009
2014	5C	4356	1	221782	222132	217634	217984
372	5C	4255	2	221781	222123	217633	217975
634	5C	4247	143	221781	222122	217633	217974
59	5C	4196	2	221781	222118	217633	217970
768	5C	4153	2	221781	222115	217633	217967
45	5C	4114	274	221780	222111	217632	217963
658	5C	4076	1	221780	222108	217632	217960
1419	5C	3815	128	221779	222086	217631	217938
778	5C	3810	1	221779	222085	217631	217937
1069	5C	3810	1	221779	222085	217631	217937
380	5C	3641	2	221778	222071	217630	217923
1877	5C	3505	1	221777	222059	217629	217911
1572	5C	3479	117	221777	222057	217629	217909
1016	5C	3459	116	221777	222055	217629	217907
1552	5C	3347	112	221776	222045	217628	217897
1163	5C	3333	1	221776	222044	217628	217896
207	5C	3291	470	221776	222040	217628	217892
1414	5C	3156	1	221775	222029	217627	217881
94	5C	3101	443	221775	222024	217627	217876
1000	5C	3096	2	221775	222024	217627	217876
1373	5C	3002	2	221774	222015	217626	217867
2016	5C	2946	1	221774	222011	217626	217863
1830	5C	2940	1	221774	222010	217626	217862
2029	5C	2868	323	221774	222004	217626	217856
1996	5C	2729	1	221773	221992	217625	217844

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
2039	5C	2706	158	221773	221990	217625	217842
2003	5C	2644	1	221773	221985	217625	217837
1924	5C	2602	131	221772	221981	217624	217833
598	5C	2470	1	221772	221970	217624	217822
659	5C	2470	1	221772	221970	217624	217822
755	5C	2470	1	221772	221970	217624	217822
225	5C	2413	1	221771	221965	217623	217817
1588	5C	2362	337	221771	221961	217623	217813
1332	5C	2222	0	221770	221949	217622	217801
1707	5C	2102	0	221770	221939	217622	217791
1994	5C	2089	1	221770	221938	217622	217790
749	5C	1990	67	221769	221929	217621	217781
1981	5C	1951	75	221769	221926	217621	217778
311	5C	1944	1	221769	221925	217621	217777
2011	5C	1924	0	221769	221924	217621	217776
1320	5C	1917	0	221769	221923	217621	217775
1966	5C	1816	1	221768	221914	217620	217766
646	5C	1782	1	221768	221911	217620	217763
1576	5C	1623	1	221767	221897	217619	217749
1984	5C	1582	47	221767	221894	217619	217746
392	5C	1510	76	221767	221888	217619	217740
803	5C	1467	49	221766	221884	217618	217736
1922	5C	1213	0	221765	221862	217617	217714
2032	5C	1135	11	221765	221856	217617	217708
2036	5C	1109	1	221765	221854	217617	217706
1733	5C	1098	0	221764	221852	217616	217704
1982	5C	1095	37	221764	221852	217616	217704
527	5C	1029	0	221764	221847	217616	217699
2007	5C	1013	145	221764	221845	217616	217697
802	5C	1006	1	221764	221845	217616	217697
326	5C	921	0	221764	221838	217616	217690
861	5C	819	0	221763	221829	217615	217681
1177	5C	794	0	221763	221827	217615	217679
46	5C	782	39	221763	221826	217615	217678
263	5C	759	0	221763	221824	217615	217676
1792	5C	750	0	221763	221823	217615	217675
182	5C	742	0	221763	221823	217615	217675
1983	5C	716	0	221762	221820	217614	217672
2012	5C	711	0	221762	221819	217614	217671
1995	5C	705	54	221762	221819	217614	217671
2037	5C	682	0	221762	221817	217614	217669
1875	5C	651	14	221762	221814	217614	217666
2038	5C	640	0	221762	221813	217614	217665
2028	5C	635	0	221762	221813	217614	217665
2013	5C	635	0	221762	221813	217614	217665
1874	5C	481	10	221761	221800	217613	217652
1598	5C	476	0	221761	221799	217613	217651
1937	5C	381	0	221761	221792	217613	217644
1950	5C	369	0	221761	221791	217613	217643
1949	5C	366	3	221761	221790	217613	217642

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1799	5C	330	0	221760	221787	217612	217639
2005	5C	316	0	221760	221785	217612	217637
1993	5C	316	0	221760	221785	217612	217637
1786	5C	311	0	221760	221785	217612	217637
1351	5C	286	0	221760	221783	217612	217635
2031	5C	273	0	221760	221782	217612	217634
1941	5C	265	3	221760	221781	217612	217633
1943	5C	248	5	221760	221780	217612	217632
2006	5C	186	22	221760	221775	217612	217627
1957	5C	184	0	221760	221775	217612	217627
1980	5C	179	0	221760	221774	217612	217626
1953	5C	159	0	221760	221773	217612	217625
2024	5C	152	22	221759	221771	217611	217623
201	5C	146	0	221759	221771	217611	217623
1944	5C	136	0	221759	221770	217611	217622
832	5C	133	0	221759	221770	217611	217622
1364	5C	127	0	221759	221769	217611	217621
2023	5C	114	16	221759	221768	217611	217620
2022	5C	114	16	221759	221768	217611	217620
1771	5C	114	0	221759	221768	217611	217620
1936	5C	108	0	221759	221768	217611	217620
2020	5C	91	13	221759	221766	217611	217618
1976	5C	89	0	221759	221766	217611	217618
787	5C	76	0	221759	221765	217611	217617
1956	5C	43	0	221759	221762	217611	217614
2034	5C	34	0	221759	221762	217611	217614
78	5C	32	0	221759	221762	217611	217614
857	5C	32	0	221759	221762	217611	217614
1942	5C	23	3	221759	221761	217611	217613
1952	5C	19	0	221759	221761	217611	217613
1772	5C	9	0	221759	221760	217611	217612
1958	6A	228014897	5841742	533385	1146414	239813	852842
1464	6A	178875184	4582782	527623	1008538	234050	714965
1316	6A	26636701	682432	509770	581384	216197	287811
573	6A	10303407	263973	507854	535555	214282	241983
1963	6A	9764246	250160	507791	534043	214219	240471
1713	6A	9669265	247727	507780	533776	214208	240204
493	6A	1901000	48704	506869	511980	213297	218408
1141	6A	476881	12218	506702	507984	213130	214412
1800	6A	394317	10102	506692	507752	213120	214180
678	6A	390713	12771	506692	507742	213120	214170
1964	6A	319843	8194	506684	507544	213111	213971
688	6A	298776	8979	506681	507484	213109	213912
1961	6A	289799	7425	506680	507459	213108	213887
1637	6A	260162	6665	506677	507376	213104	213803
1232	6A	245758	6296	506675	507336	213103	213764
1710	6A	201526	5163	506670	507212	213097	213639
1764	6A	117640	3014	506660	506976	213088	213404
1486	6A	31123	797	506650	506734	213077	213161
1348	6B	7333669	308014	294381	883747	286287	875653

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823	6B	7164411	300905	293475	869238	285381	861144
1377	6B	5467226	229623	284394	723764	276300	715670
757	6B	5415226	227440	284116	719307	276022	711213
489	6B	5377111	225839	283912	716040	275818	707946
1135	6B	5251611	220568	283240	705282	275146	697188
1356	6B	5056531	212374	282196	688561	274102	680467
922	6B	4188108	175901	277550	614125	269456	606031
881	6C	3190424	133998	238529	494925	234381	490777
1705	6C	3125243	131260	238186	489344	234038	485196
903	6C	2983268	125297	237440	477188	233292	473040
900	6C	2399329	100772	234370	427191	230222	423043
896	6C	2198468	92336	233315	409994	229167	405846
870	6C	2170008	91140	233165	407556	229017	403408
761	6C	2099382	88174	232794	401510	228646	397362
1343	6C	1992311	83677	232231	392342	228083	388194
1344	6C	1789180	75146	231163	374949	227015	370801
1406	6C	1617443	67933	230261	360246	226113	356098
1353	6C	1594988	66990	230143	358323	225995	354175
1403	6C	1408268	59147	229161	342336	225013	338188
1455	6C	1306314	54865	228625	333606	224477	329458
1080	6C	1091502	45843	227496	315214	223348	311066
518	6C	1065969	44771	227362	313028	223214	308880
1407	6C	1063641	44673	227350	312829	223202	308681
907	6C	1051454	44161	227286	311785	223138	307637
579	6C	1018107	42760	227110	308930	222962	304782
905	6C	995508	41811	226991	306994	222843	302846
1081	6C	990233	41590	226964	306543	222816	302395
1441	6C	930860	39096	226652	301460	222504	297312
714	6C	926907	38930	226631	301121	222483	296973
845	6C	894199	37556	226459	298321	222311	294173
584	6C	862911	36242	226294	295641	222146	291493
1386	6C	835228	35080	226149	293272	222001	289124
792	6C	809708	34008	226015	291087	221867	286939
871	6C	762773	32036	225768	287068	221620	282920
855	6C	734576	30852	225620	284654	221472	280506
1426	6C	680847	28596	225337	280053	221189	275905
581	6C	676598	28417	225315	279689	221167	275541
1337	6C	600388	25216	224915	273165	220767	269017
1427	6C	594396	24965	224883	272651	220735	268503
532	6C	544890	22885	224623	268413	220475	264265
874	6C	511964	21502	224450	265594	220302	261446
952	6C	496277	20844	224367	264250	220219	260102
837	6C	478775	20109	224275	262751	220127	258603
531	6C	472810	19858	224244	262241	220096	258093
850	6C	463878	19483	224197	261476	220049	257328
902	6C	457820	19228	224165	260957	220017	256809
868	6C	384149	16134	223778	254650	219630	250502
1269	6C	362582	15228	223665	252804	219517	248656
809	6C	350204	14709	223600	251744	219452	247596
585	6C	348244	14626	223589	251575	219441	247427

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1425	6C	338569	14220	223538	250747	219390	246599
1408	6C	338542	14219	223538	250745	219390	246597
1400	6C	316542	13295	223423	248862	219275	244714
1360	6C	313740	13177	223408	248622	219260	244474
580	6C	309116	12983	223384	248226	219236	244078
1079	6C	301993	12684	223346	247615	219198	243467
912	6C	301868	12678	223345	247604	219197	243456
813	6C	293719	12336	223303	246908	219155	242760
1445	6C	290726	12210	223287	246651	219139	242503
899	6C	289924	12177	223283	246583	219135	242435
1078	6C	289536	12160	223281	246549	219133	242401
764	6C	284373	11944	223253	246106	219105	241958
1443	6C	279966	11759	223230	245729	219082	241581
836	6C	268002	11256	223167	244705	219019	240557
819	6C	260234	10930	223127	244041	218979	239893
854	6C	248875	10453	223067	243068	218919	238920
815	6C	221317	9295	222922	240708	218774	236560
1437	6C	220488	9260	222918	240637	218770	236489
1352	6C	217285	9126	222901	240363	218753	236215
1404	6C	205551	8633	222839	239358	218691	235210
1355	6C	201526	8464	222818	239014	218670	234866
1376	6C	201072	8445	222816	238975	218668	234827
866	6C	189450	7957	222755	237980	218607	233832
1390	6C	181202	7610	222711	237273	218563	233125
897	6C	173474	7286	222671	236612	218523	232464
456	6C	169436	7116	222649	236266	218501	232118
821	6C	169146	7104	222648	236241	218500	232093
784	6C	167272	7025	222638	236081	218490	231933
842	6C	159208	6687	222596	235391	218448	231243
1113	6C	157123	6599	222585	235212	218437	231064
825	6C	148329	6230	222538	234458	218390	230310
1385	6C	139056	5840	222490	233665	218342	229517
1921	6C	136030	5713	222474	233406	218326	229258
765	6C	128091	5380	222432	232726	218284	228578
1339	6C	126934	5331	222426	232627	218278	228479
883	6C	125960	5290	222421	232544	218273	228396
583	6C	125335	5264	222418	232490	218270	228342
1378	6C	124941	5248	222415	232456	218267	228308
839	6C	123928	5205	222410	232369	218262	228221
684	6C	117798	4948	222378	231845	218230	227697
483	6C	117035	4915	222374	231779	218226	227631
898	6C	110931	4659	222342	231257	218194	227109
1449	6C	109359	4593	222334	231123	218186	226975
1405	6C	100829	4235	222289	230392	218141	226244
873	6C	99763	4190	222283	230300	218135	226152
810	6C	97902	4112	222273	230141	218125	225993
962	6C	97238	4084	222270	230084	218122	225936
1350	6C	93712	3936	222251	229782	218103	225634
800	6C	88168	3703	222222	229308	218074	225160
1345	6C	86148	3618	222212	229135	218064	224987

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829	6C	84622	3554	222204	229005	218056	224857
504	6C	83307	3499	222197	228892	218049	224744
1354	6C	82610	3470	222193	228832	218045	224684
790	6C	82182	3452	222191	228796	218043	224648
830	6C	81775	3435	222189	228761	218041	224613
1057	6C	79749	3349	222178	228587	218030	224439
486	6C	79269	3329	222175	228545	218027	224397
844	6C	78598	3301	222172	228488	218024	224340
849	6C	78598	3301	222172	228488	218024	224340
915	6C	76960	3232	222163	228348	218015	224200
785	6C	76598	3217	222161	228317	218013	224169
1266	6C	73375	3082	222144	228041	217996	223893
805	6C	71100	2986	222132	227846	217984	223698
582	6C	66417	2790	222108	227446	217960	223298
910	6C	65509	2751	222103	227368	217955	223220
500	6C	61273	2573	222081	227005	217933	222857
816	6C	58432	2454	222066	226762	217918	222614
1335	6C	57985	2435	222063	226723	217915	222575
1369	6C	57419	2412	222061	226675	217913	222527
834	6C	54420	2286	222045	226418	217897	222270
1446	6C	52828	2219	222036	226281	217888	222133
822	6C	52789	2217	222036	226278	217888	222130
838	6C	50737	2131	222025	226102	217877	221954
828	6C	48586	2041	222014	225919	217866	221771
669	6C	43627	1832	221988	225494	217840	221346
1375	6C	43489	1827	221987	225482	217839	221334
895	6C	43298	1819	221986	225466	217838	221318
760	6C	42318	1777	221981	225382	217833	221234
1454	6C	40430	1698	221971	225220	217823	221072
105	6C	40331	1694	221971	225212	217823	221064
947	6C	40233	1690	221970	225203	217822	221055
1388	6C	36273	1523	221949	224864	217801	220716
683	6C	35267	1481	221944	224778	217796	220630
516	6C	35267	1481	221944	224778	217796	220630
843	6C	35267	1481	221944	224778	217796	220630
852	6C	35267	1481	221944	224778	217796	220630
1428	6C	35267	1481	221944	224778	217796	220630
911	6C	33860	1422	221937	224658	217789	220510
1142	6C	32255	1355	221928	224520	217780	220372
1381	6C	31413	1319	221924	224448	217776	220300
766	6C	29755	1250	221915	224306	217767	220158
858	6C	28992	1218	221911	224241	217763	220093
1450	6C	28223	1185	221907	224175	217759	220027
1340	6C	27789	1167	221905	224138	217757	219990
923	6C	27236	1144	221902	224091	217754	219943
1143	6C	26703	1122	221899	224045	217751	219897
893	6C	25664	1078	221894	223956	217746	219808
1341	6C	25572	1074	221893	223948	217745	219800
853	6C	24711	1038	221889	223875	217741	219727
786	6C	23698	995	221883	223787	217735	219639

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791	6C	23566	990	221883	223777	217735	219629
795	6C	23185	974	221881	223744	217733	219596
943	6C	22178	931	221875	223657	217727	219509
794	6C	20652	867	221867	223527	217719	219379
774	6C	20488	860	221866	223513	217718	219365
812	6C	20159	847	221865	223485	217717	219337
775	6C	20153	846	221865	223485	217717	219337
886	6C	20153	846	221865	223485	217717	219337
901	6C	20153	846	221865	223485	217717	219337
783	6C	19666	826	221862	223442	217714	219294
1072	6C	18831	791	221858	223371	217710	219223
1264	6C	18745	787	221857	223363	217709	219215
867	6C	18140	762	221854	223312	217706	219164
797	6C	18133	762	221854	223311	217706	219163
862	6C	15114	635	221838	223053	217690	218905
1424	6C	15114	635	221838	223053	217690	218905
1383	6C	14496	609	221835	223000	217687	218852
1338	6C	14496	609	221835	223000	217687	218852
817	6C	14108	593	221833	222967	217685	218819
1409	6C	13036	548	221827	222875	217679	218727
798	6C	12089	508	221822	222794	217674	218646
1137	6C	11800	496	221821	222769	217673	218621
851	6C	10076	423	221812	222622	217664	218474
926	6C	9077	381	221806	222535	217658	218387
1044	6C	8886	373	221805	222519	217657	218371
801	6C	8064	339	221801	222449	217653	218301
1452	6C	8064	339	221801	222449	217653	218301
906	6C	7557	317	221798	222405	217650	218257
856	6C	7248	304	221797	222379	217649	218231
1347	6C	7248	304	221797	222379	217649	218231
820	6C	7057	296	221796	222363	217648	218215
826	6C	7051	296	221796	222363	217648	218215
880	6C	6847	288	221795	222345	217647	218197
840	6C	6044	254	221790	222276	217642	218128
882	6C	6044	254	221790	222276	217642	218128
796	6C	6044	254	221790	222276	217642	218128
1336	6C	6044	254	221790	222276	217642	218128
763	6C	5597	235	221788	222238	217640	218090
814	6C	5045	212	221785	222190	217637	218042
1451	6C	4032	169	221780	222104	217632	217956
1402	6C	4025	169	221780	222103	217632	217955
864	6C	3026	127	221775	222018	217627	217870
1382	6C	2815	118	221773	221999	217625	217851
888	6C	1960	82	221769	221927	217621	217779
1308	7A	28573431	1755998	713544	1247705	571594	1105755
265	7A	27138101	1972740	708217	1215546	566268	1073597
1170	7A	25260880	748412	701251	1173486	559301	1031536
147	7A	24767947	2207938	699421	1162441	557472	1020492
1217	7A	24040898	1238060	696723	1146152	554773	1004202
129	7A	23629526	2346110	695196	1136934	553247	994985

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120	7A	23554699	1725748	694919	1135258	552969	993308
1765	7A	21446453	536450	687095	1088022	545145	946072
665	7A	20642380	2057909	684111	1070006	542161	928056
1711	7A	20048325	514115	681906	1056696	539956	914746
161	7A	19770016	79754	680873	1050460	538924	908511
1297	7A	19447690	1442868	679677	1043239	537727	901289
1291	7A	19338172	1104782	679270	1040784	537321	898835
193	7A	18400878	1525032	675792	1019784	533842	877834
604	7A	16309117	1433074	668029	972917	526080	830968
1305	7A	16020574	1349343	666958	966452	525009	824503
298	7A	15721090	1178990	665847	959742	523897	817792
939	7A	15631527	1266256	665514	957735	523565	815786
1183	7A	15614839	1085181	665453	957362	523503	815412
1418	7A	15569278	862665	665283	956340	523334	814391
552	7A	14933378	346498	662924	942094	520974	800144
1181	7A	14625134	527460	661780	935187	519830	793237
148	7A	13633094	1202916	658098	912960	516148	771010
1754	7A	12836360	395576	655141	895108	513192	753159
142	7A	12410387	1133533	653560	885564	511611	743615
269	7A	12376246	1459216	653434	884800	511484	742850
1913	7A	12296678	655552	653138	883016	511189	741067
1758	7A	11558794	826487	650400	866484	508450	724534
1148	7A	11546124	1012566	650353	866200	508403	724250
140	7A	11517697	878321	650247	865563	508298	723614
651	7A	11455077	259812	650015	864160	508065	722210
139	7A	11414429	680809	649864	863249	507915	721300
1648	7A	10570510	22068	646732	844341	504783	702392
1281	7A	10532456	381894	646591	843488	504641	701538
132	7A	10522973	1347675	646556	843276	504606	701326
1420	7A	10445915	508181	646270	841549	504320	699599
1237	7A	10333826	726482	645854	839038	503904	697088
1290	7A	9277837	55428	641935	815378	499985	673428
1166	7A	9232904	166022	641768	814371	499818	672421
588	7A	9155916	425197	641482	812646	499533	670697
578	7A	8420289	345825	638752	796164	496803	654215
1154	7A	8363576	316549	638542	794893	496592	652943
173	7A	8222845	7211	638020	791741	496070	649791
271	7A	8040595	468132	637343	787657	495394	645708
128	7A	7814208	424603	636503	782584	494553	640634
1240	7A	7505014	533323	635356	775657	493406	633707
1311	7A	7340841	497232	634746	771978	492797	630029
1741	7A	7320408	283318	634670	771520	492721	629571
246	7A	7217421	364835	634288	769213	492339	627264
1157	7A	7179584	330161	634148	768366	492198	626416
1174	7A	7147313	342219	634028	767642	492079	625693
232	7A	7110069	401410	633890	766808	491940	624858
1256	7A	6949378	19052	633294	763208	491344	621258
1366	7A	6937281	1457	633249	762937	491299	620987
131	7A	6899140	22786	633107	762082	491157	620132
1715	7A	6808544	467601	632771	760052	490821	618102

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1209	7A	6793627	369749	632716	759718	490766	617768
1228	7A	6453496	22076	631453	752097	489504	610148
1295	7A	6429528	275767	631364	751560	489415	609611
699	7A	6271076	220853	630776	748010	488827	606061
1292	7A	6185073	237803	630457	746083	488507	604133
1225	7A	6012244	113596	629816	742211	487866	600261
1761	7A	5912359	353619	629445	739973	487495	598023
1205	7A	5825937	114051	629124	738036	487175	596087
1259	7A	5737211	176297	628795	736048	486845	594098
1413	7A	5711819	25662	628701	735480	486751	593530
134	7A	5680851	29553	628586	734786	486636	592836
555	7A	5529606	385145	628025	731397	486075	589447
1241	7A	5357151	153643	627385	727533	485435	585583
1539	7A	5317269	420048	627236	726639	485287	584690
1253	7A	5268646	24861	627056	725550	485106	583600
557	7A	5239162	76681	626947	724890	484997	582940
733	7A	5180113	207885	626727	723566	484778	581617
931	7A	5074921	231865	626337	721209	484388	579260
135	7A	5031057	42601	626174	720226	484225	578277
169	7A	4893909	689742	625665	717153	483716	575204
738	7A	4857231	75428	625529	716332	483580	574383
1315	7A	4758836	117657	625164	714127	483214	572177
1775	7A	4695361	45584	624928	712705	482979	570756
155	7A	4578505	252770	624495	710087	482545	568137
145	7A	4487550	508067	624157	708049	482208	566100
1619	7A	4472479	22041	624101	707711	482152	565762
1155	7A	4467966	121433	624085	707611	482135	565661
1631	7A	4434333	1077	623960	706857	482010	564907
241	7A	4350173	14400	623647	704971	481698	563022
1195	7A	4284723	144234	623405	703505	481455	561555
1219	7A	4273784	117865	623364	703260	481414	561310
1750	7A	4138079	47404	622860	700219	480911	558270
1664	7A	4059271	22342	622568	698453	480618	556503
770	7A	3920485	189641	622053	695344	480103	553394
1911	7A	3888755	58567	621935	694633	479985	552683
1248	7A	3823475	31853	621693	693170	479743	551220
1139	7A	3790264	158803	621570	692426	479620	550476
1912	7A	3789819	184924	621568	692416	479618	550466
620	7A	3671861	19063	621130	689773	479181	547824
929	7A	3664850	11372	621104	689616	479154	547666
1220	7A	3599378	134751	620861	688149	478912	546200
1399	7A	3591199	150830	620831	687966	478881	546016
1221	7A	3549726	58241	620677	687037	478727	545087
751	7A	3538193	24057	620634	686778	478684	544828
420	7A	3502376	841	620501	685976	478552	544027
189	7A	3463483	150836	620357	685104	478407	543154
405	7A	3459258	46296	620341	685010	478391	543060
668	7A	3456022	12974	620329	684937	478379	542987
524	7A	3424024	56519	620210	684220	478261	542271
144	7A	3411165	362574	620163	683932	478213	541982

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1967	7A	3409810	60855	620158	683902	478208	541952
1827	7A	3371642	1007	620016	683047	478066	541097
1171	7A	3355776	37772	619957	682691	478007	540741
663	7A	3321474	88058	619830	681923	477880	539973
1788	7A	3306845	2841	619775	681594	477826	539645
1930	7A	3289380	94328	619711	681204	477761	539254
289	7A	3202568	172306	619388	679258	477439	537309
523	7A	3197692	184076	619370	679149	477421	537200
917	7A	3131657	129821	619125	677669	477176	535720
176	7A	3117100	161818	619071	677343	477122	535394
1208	7A	3115656	5737	619066	677311	477116	535361
1223	7A	2992850	179677	618610	674559	476661	532610
1803	7A	2952450	620	618460	673654	476511	531705
353	7A	2903669	189740	618279	672561	476330	530612
1699	7A	2898320	56030	618259	672441	476310	530492
151	7A	2893058	47012	618240	672324	476290	530374
1709	7A	2815503	20601	617952	670586	476002	528636
1932	7A	2741585	147205	617678	668930	475728	526980
737	7A	2728027	1478	617627	668626	475678	526677
378	7A	2691382	81361	617491	667805	475542	525856
1287	7A	2627238	165593	617253	666367	475304	524418
1916	7A	2553474	151691	616980	664715	475030	522765
1760	7A	2537677	45276	616921	664361	474971	522411
1136	7A	2536468	102830	616916	664334	474967	522385
735	7A	2440192	93462	616559	662177	474610	520228
1508	7A	2439174	18296	616555	662154	474606	520205
1541	7A	2434736	140016	616539	662055	474589	520105
412	7A	2410515	709	616449	661512	474499	519562
457	7A	2409686	78689	616446	661493	474496	519543
1202	7A	2250829	193589	615856	657934	473907	515985
214	7A	2210257	72882	615706	657025	473756	515075
1968	7A	2180150	58495	615594	656350	473645	514401
708	7A	2114351	848	615350	654876	473400	512926
1965	7A	2112283	1304	615342	654830	473393	512881
628	7A	2101232	39939	615301	654582	473352	512633
1752	7A	2068323	42640	615179	653845	473230	511896
1303	7A	2046601	111225	615098	653358	473149	511409
1671	7A	2043302	66457	615086	653284	473137	511335
1822	7A	1983209	44346	614863	651938	472914	509989
1301	7A	1959653	85220	614776	651410	472826	509460
423	7A	1941496	631	614708	651003	472759	509054
1431	7A	1924478	16822	614645	650622	472696	508673
367	7A	1865566	97561	614427	649303	472477	507353
718	7A	1847595	41593	614360	648900	472410	506950
190	7A	1826083	58041	614280	648417	472331	506468
918	7A	1728050	55699	613916	646221	471967	504272
1302	7A	1706325	59320	613836	645735	471886	503785
168	7A	1703098	18468	613824	645662	471874	503712
124	7A	1689881	111771	613775	645366	471825	503416
1759	7A	1683966	157142	613753	645234	471803	503284

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1753	7A	1659585	349	613662	644687	471713	502738
1359	7A	1623697	63445	613529	643883	471579	501933
1293	7A	1619012	31425	613512	643778	471562	501828
833	7A	1618026	56219	613508	643756	471558	501806
319	7A	1602691	2739	613451	643412	471501	501462
1919	7A	1546666	325	613243	642157	471294	500208
935	7A	1526315	7031	613168	641701	471218	499751
1156	7A	1476936	38885	612984	640594	471035	498645
136	7A	1461111	166216	612926	640240	470976	498290
491	7A	1448744	16379	612880	639963	470930	498013
772	7A	1448280	60619	612878	639953	470928	498003
66	7A	1387775	75362	612653	638597	470704	496648
1732	7A	1384939	1028	612643	638534	470693	496584
1823	7A	1379036	56023	612621	638401	470671	496451
1621	7A	1354231	30787	612529	637845	470579	495895
1659	7A	1344328	49852	612492	637623	470543	495674
1184	7A	1342734	115801	612486	637588	470537	495639
361	7A	1340899	51660	612480	637547	470530	495597
670	7A	1333661	3203	612453	637385	470503	495435
1740	7A	1312908	276	612376	636920	470426	494970
1374	7A	1309768	53871	612364	636849	470414	494899
1165	7A	1286412	32398	612277	636326	470328	494377
769	7A	1272053	7979	612224	636004	470274	494054
758	7A	1251606	31709	612148	635546	470199	493597
317	7A	1215932	97703	612016	634747	470066	492797
1146	7A	1205068	7790	611975	634503	470026	492554
1975	7A	1203710	9050	611970	634473	470021	492524
1246	7A	1198683	15079	611952	634361	470002	492411
1149	7A	1195308	44486	611939	634284	469990	492335
1970	7A	1178146	247	611876	633901	469926	491951
894	7A	1159273	48684	611805	633477	469856	491528
1931	7A	1154410	9619	611787	633368	469838	491419
390	7A	1151054	2890	611775	633293	469825	491343
178	7A	1141690	4612	611740	633083	469791	491134
572	7A	1105043	13380	611604	632262	469655	490313
1714	7A	1100651	22015	611588	632164	469638	490214
560	7A	1042374	98154	611372	630858	469422	488908
1861	7A	1002992	7695	611225	629975	469276	488026
773	7A	1001535	41730	611220	629943	469270	487993
1178	7A	996264	38066	611201	629825	469251	487875
553	7A	995291	4541	611197	629803	469247	487853
1285	7A	988525	61945	611172	629652	469222	487702
1153	7A	975583	27739	611124	629362	469174	487412
408	7A	964231	390	611082	629108	469132	487158
382	7A	955858	1844	611051	628920	469101	486970
1748	7A	928062	14519	610947	628297	468998	486348
1971	7A	868787	9727	610727	626968	468778	485019
875	7A	856605	35971	610682	626696	468733	484747
1611	7A	856373	11835	610681	626690	468732	484741
1886	7A	850050	28057	610658	626549	468708	484599

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
109	7A	846081	64650	610643	626460	468694	484511
448	7A	763841	1397	610338	624617	468388	482667
1651	7A	733390	6389	610225	623935	468275	481985
1638	7A	722790	16408	610186	623698	468236	481748
723	7A	707110	2410	610127	623346	468178	481397
780	7A	667272	415	609980	622454	468030	480504
1716	7A	645093	135	609897	621957	467948	480008
1681	7A	644828	194	609896	621951	467947	480002
1615	7A	643684	177	609892	621925	467942	479975
42	7A	640920	31298	609882	621864	467932	479914
363	7A	627016	15089	609830	621552	467881	479603
1700	7A	621597	131	609810	621430	467860	479480
314	7A	618894	215	609800	621370	467850	479420
1683	7A	612497	8575	609776	621226	467827	479277
247	7A	610923	7406	609770	621191	467821	479242
253	7A	610598	50961	609769	621184	467820	479235
36	7A	603496	57012	609743	621025	467793	479075
194	7A	599709	48065	609729	620940	467779	478990
1742	7A	596455	15791	609717	620867	467767	478917
1469	7A	587161	25940	609682	620659	467733	478710
85	7A	585454	6306	609676	620621	467726	478671
562	7A	577237	21824	609645	620436	467696	478487
89	7A	561773	213	609588	620090	467638	478140
653	7A	550264	2907	609545	619832	467596	477883
230	7A	546146	59131	609530	619740	467580	477790
71	7A	544396	221	609524	619701	467574	477751
1920	7A	540214	5006	609508	619607	467558	477657
180	7A	537139	27147	609497	619538	467547	477588
70	7A	525645	29072	609454	619281	467504	477331
753	7A	518491	8684	609427	619120	467478	477171
56	7A	516660	49568	609421	619080	467471	477130
279	7A	513099	2938	609407	618999	467458	477050
171	7A	502172	67908	609367	618755	467417	476805
1548	7A	483055	101	609296	618326	467346	476376
50	7A	483031	891	609296	618326	467346	476376
736	7A	472508	1163	609257	618090	467307	476140
122	7A	461154	805	609215	617836	467265	475886
732	7A	459821	875	609210	617806	467260	475856
1889	7A	456739	907	609198	617736	467249	475787
1858	7A	436866	2974	609124	617291	467175	475342
1460	7A	434279	91	609115	617234	467165	475284
54	7A	429594	24543	609097	617128	467148	475179
1480	7A	423291	32001	609074	616987	467125	475038
1493	7A	421928	166	609069	616957	467119	475007
1447	7A	421354	17678	609067	616944	467117	474994
234	7A	416350	87	609048	616831	467099	474882
215	7A	412878	26054	609035	616753	467086	474804
195	7A	406928	4851	609013	616620	467064	474671
1724	7A	396244	211	608974	616382	467024	474432
286	7A	395736	484	608972	616370	467022	474420

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
1682	7A	393330	20006	608963	616316	467013	474366
1755	7A	390505	661	608952	616252	467003	474303
1185	7A	383446	18420	608926	616094	466977	474145
1693	7A	381559	23724	608919	616052	466970	474103
789	7A	378247	14886	608907	615978	466957	474028
666	7A	371106	2885	608880	615818	466931	473869
1204	7A	355282	25738	608822	615464	466872	473514
268	7A	352788	717	608812	615407	466863	473458
687	7A	350127	74	608803	615348	466853	473398
1777	7A	346304	640	608788	615262	466839	473313
1665	7A	340871	4874	608768	615140	466819	473191
1242	7A	332212	16412	608736	614946	466786	472996
181	7A	321725	662	608697	614711	466748	472762
463	7A	313706	419	608667	614532	466718	472583
1933	7A	310198	65	608654	614453	466705	472504
1512	7A	301974	17379	608624	614269	466674	472319
502	7A	287150	18932	608569	613937	466619	471987
200	7A	274298	202	608521	613649	466572	471700
1394	7A	270722	137	608508	613569	466558	471619
447	7A	270364	33063	608507	613561	466557	471611
1851	7A	268420	56	608499	613517	466550	471568
544	7A	259036	151	608465	613308	466515	471358
799	7A	257382	9488	608458	613270	466509	47132[illegible]
167	7A	253412	497	608444	613181	466494	471231
1238	7A	251315	15733	608436	613134	466486	471184
1756	7A	248800	27612	608427	613078	466477	471128
1159	7A	247150	3138	608420	613040	466471	471091
1496	7A	247137	52	608420	613040	466471	471091
703	7A	243556	51	608407	612960	466457	471010
1313	7A	241175	6729	608398	612907	466449	470958
884	7A	239791	6513	608393	612876	466444	470927
90	7A	239366	109	608392	612867	466442	470917
360	7A	238521	1515	608388	612847	466439	470898
300	7A	237433	9225	608384	612823	466435	470874
1312	7A	229497	11372	608355	612645	466405	470695
890	7A	225978	7949	608342	612567	466392	470617
366	7A	225199	17366	608339	612549	466389	470599
137	7A	222567	3018	608329	612490	466380	470541
1717	7A	217622	5682	608311	612379	466361	470429
1371	7A	214943	2381	608301	612319	466351	470369
558	7A	204551	508	608262	612086	466313	470137
681	7A	203778	43	608259	612068	466310	470119
1864	7A	203048	43	608257	612053	466307	470103
313	7A	202042	259	608253	612030	466303	470080
102	7A	199850	248	608245	611981	466295	470031
1358	7A	199413	606	608243	611971	466294	470022
172	7A	198475	42	608240	611950	466290	470000
1507	7A	191942	1166	608216	611804	466266	469854
154	7A	183571	15605	608184	611616	466235	469667
368	7A	182306	86	608180	611588	466230	469638

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244	7A	182141	39	608179	611584	466230	469635
1516	7A	179759	8558	608170	611530	466221	469581
1855	7A	178878	43	608167	611511	466217	469561
470	7A	176458	41	608158	611457	466208	469507
1506	7A	175302	50	608154	611431	466204	469481
150	7A	174802	37	608152	611420	466202	469470
65	7A	174789	12568	608152	611420	466202	469470
1468	7A	170473	36	608136	611323	466186	469373
383	7A	166590	60	608121	611235	466172	469286
1152	7A	165503	4262	608117	611211	466168	469262
1	7A	158275	33	608091	611050	466141	469100
12	7A	158210	7699	608090	611048	466141	469099
1649	7A	152318	595	608068	610915	466119	468966
728	7A	147651	31	608051	610811	466102	468862
4	7A	146703	31	608048	610791	466098	468841
1140	7A	145817	456	608044	610770	466095	468821
1883	7A	144798	2296	608041	610748	466091	468798
782	7A	144340	1081	608039	610737	466089	468787
1304	7A	142576	30	608032	610697	466083	468748
1929	7A	142295	43	608031	610691	466082	468742
1757	7A	141966	30	608030	610684	466080	468734
641	7A	141047	30	608027	610664	466077	468714
166	7A	140946	6997	608026	610661	466077	468712
1696	7A	140307	29	608024	610647	466074	468697
294	7A	140289	31	608024	610647	466074	468697
356	7A	137622	6176	608014	610587	466064	468637
272	7A	136632	29	608010	610564	466061	468615
350	7A	135240	154	608005	610533	466055	468583
1515	7A	132368	28	607994	610469	466045	468520
1610	7A	127993	47	607978	610371	466029	468422
589	7A	125760	177	607970	610321	466020	468371
88	7A	123388	61	607961	610268	466012	468319
455	7A	120547	167	607951	610205	466001	468255
1471	7A	119939	5247	607948	610190	465999	468241
153	7A	119584	11516	607947	610183	465997	468233
130	7A	117023	33	607937	610125	465988	468176
458	7A	115814	180	607933	610098	465983	468148
1151	7A	113853	2391	607926	610054	465976	468104
1613	7A	113653	8592	607925	610050	465975	468100
69	7A	113437	46	607924	610045	465975	468096
1860	7A	113343	42	607924	610043	465974	468093
1666	7A	113289	698	607924	610042	465974	468092
146	7A	113152	14118	607923	610038	465974	468089
576	7A	113092	24	607923	610037	465973	468087
445	7A	112012	300	607919	610013	465969	468063
593	7A	111997	158	607919	610013	465969	468063
450	7A	111746	2347	607918	610007	465968	468057
1809	7A	111299	37	607916	609997	465967	468048
1795	7A	110758	43	607914	609985	465965	468036
891	7A	110562	109	607914	609981	465964	468031

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1214	7A	106032	4958	607897	609879	465947	467929
23	7A	104325	30	607890	609840	465941	467891
1885	7A	101760	21	607881	609783	465931	467833
1617	7A	101693	42	607881	609782	465931	467832
1805	7A	96463	20	607861	609664	465912	467715
550	7A	95679	20	607858	609647	465909	467698
808	7A	95343	109	607857	609639	465907	467689
10	7A	94488	4573	607854	609620	465904	467670
1532	7A	94437	102	607854	609619	465904	467669
183	7A	92358	426	607846	609573	465896	467623
1147	7A	92267	3134	607846	609571	465896	467621
1466	7A	92107	6846	607845	609567	465895	467617
2009	7A	91215	278	607842	609547	465892	467597
465	7A	87958	137	607830	609474	465880	467524
399	7A	87805	1857	607829	609470	465879	467520
1735	7A	87271	18	607827	609458	465877	467508
1590	7A	86480	18	607824	609441	465875	467492
1834	7A	85907	18	607822	609428	465872	467478
1915	7A	85135	2711	607819	609411	465870	467462
1863	7A	84629	18	607817	609399	465868	467450
1645	7A	83042	18	607811	609363	465862	467414
644	7A	81378	17	607805	609326	465856	467377
1798	7A	80746	17	607803	609312	465853	467362
762	7A	80524	1491	607802	609307	465852	467357
811	7A	78259	3254	607794	609257	465844	467307
1894	7A	77304	16	607790	609235	465840	467285
1270	7A	77245	19	607790	609234	465840	467284
1686	7A	76814	28	607788	609224	465839	467275
1167	7A	75896	3038	607785	609204	465835	467254
1389	7A	75578	3174	607784	609197	465834	467247
779	7A	71423	362	607768	609103	465819	467154
1432	7A	70955	15	607767	609093	465817	467143
1766	7A	70918	1489	607766	609092	465817	467143
1896	7A	67418	300	607753	609013	465804	467064
1722	7A	64241	13	607742	608943	465792	466993
1481	7A	63040	4766	607737	608915	465788	466966
596	7A	59094	1344	607723	608828	465773	466878
528	7A	59035	20	607722	608826	465773	466877
1636	7A	57791	583	607718	608798	465768	466848
1247	7A	57780	162	607718	608798	465768	466848
251	7A	57225	12	607716	608786	465766	466836
804	7A	57162	13	607715	608784	465766	466835
1849	7A	57132	1667	607715	608783	465766	466834
1582	7A	56797	12	607714	608776	465764	466826
1479	7A	56686	4285	607714	608774	465764	466824
275	7A	56626	48	607713	608772	465764	466823
1797	7A	56487	15	607713	608769	465763	466819
417	7A	55882	15	607711	608756	465761	466806
18	7A	55575	12	607709	608748	465760	466799
1618	7A	55515	24	607709	608747	465760	466798

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250	7A	54923	15	607707	608734	465757	466784
5	7A	54863	1430	607707	608733	465757	466783
542	7A	53766	23	607703	608708	465753	466758
29	7A	52572	1104	607698	608681	465749	466732
1914	7A	51947	1091	607696	608667	465746	466717
1586	7A	49633	111	607687	608615	465738	466666
534	7A	48724	10	607684	608595	465734	466645
1483	7A	48501	10	607683	608590	465734	466641
254	7A	46657	115	607676	608548	465727	466599
1836	7A	46240	9	607675	608539	465725	466589
418	7A	46023	9	607674	608534	465724	466584
827	7A	45841	356	607673	608530	465724	466581
435	7A	45657	10	607673	608527	465723	466577
199	7A	45171	17	607671	608515	465721	466565
1387	7A	43939	1824	607666	608487	465717	466538
1856	7A	43576	40	607665	608480	465715	466530
674	7A	42279	9	607660	608450	465711	466501
1547	7A	41948	9	607659	608443	465709	466493
713	7A	41695	9	607658	608437	465708	466487
1991	7A	41502	9	607657	608433	465708	466484
1429	7A	41055	1693	607656	608423	465706	466473
302	7A	40972	9	607655	608421	465706	466472
1853	7A	40866	663	607655	608419	465705	466469
1594	7A	40432	8	607653	608409	465704	466460
529	7A	38921	8	607648	608376	465698	466426
1501	7A	38072	8	607644	608356	465695	466407
376	7A	37687	2629	607643	608348	465693	466398
1439	7A	37531	8	607642	608344	465693	466395
459	7A	36913	35	607640	608330	465691	466381
1854	7A	33127	2197	607626	608245	465677	466296
222	7A	32167	7	607623	608224	465673	466274
111	7A	32099	7	607622	608222	465673	466273
541	7A	31294	39	607619	608204	465670	466255
384	7A	31029	374	607618	608198	465669	466249
520	7A	30861	9	607618	608195	465668	466245
436	7A	27652	8	607606	608123	465656	466173
860	7A	27351	222	607605	608116	465655	466166
1890	7A	26825	9	607603	608104	465653	466154
97	7A	26502	1832	607602	608097	465652	466147
1901	7A	25995	6	607600	608086	465650	466136
1812	7A	25847	5	607599	608082	465650	466133
349	7A	25580	9	607598	608076	465649	466127
1584	7A	25385	5	607597	608072	465648	466123
569	7A	25383	401	607597	608072	465648	466123
345	7A	25353	5	607597	608071	465648	466122
1279	7A	25268	5	607597	608069	465647	466119
95	7A	24861	1879	607595	608060	465646	466111
1514	7A	24823	95	607595	608059	465646	466110
396	7A	24321	12	607593	608048	465644	466099
793	7A	24038	10	607592	608041	465643	466092

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1898	7A	23639	496	607591	608033	465641	466083
1138	7A	23428	492	607590	608028	465641	466079
1808	7A	22571	5	607587	608009	465637	466059
664	7A	22145	140	607585	607999	465636	466050
460	7A	21932	50	607585	607995	465635	466045
358	7A	21012	10	607581	607974	465632	466025
477	7A	20497	4	607579	607962	465630	466013
1633	7A	20282	4	607578	607957	465629	466008
138	7A	18563	4	607572	607919	465622	465969
1277	7A	18082	404	607570	607908	465621	465959
365	7A	17942	4	607570	607905	465620	465955
1391	7A	16646	3	607565	607876	465615	465926
7	7A	16572	202	607565	607875	465615	465925
175	7A	16371	21	607564	607870	465614	465920
1585	7A	15268	578	607560	607845	465610	465895
691	7A	14884	313	607558	607836	465609	465887
149	7A	14745	3	607558	607834	465608	465884
586	7A	14468	3	607557	607827	465607	465877
1935	7A	14438	3	607557	607827	465607	465877
206	7A	14403	3	607557	607826	465607	465876
1739	7A	14132	237	607556	607820	465606	465870
1701	7A	12621	3	607550	607786	465600	465836
563	7A	12433	3	607549	607781	465600	465832
1850	7A	12216	3	607549	607777	465599	465827
1436	7A	11930	3	607547	607770	465598	465821
1738	7A	11245	2	607545	607755	465595	465805
872	7A	11242	466	607545	607755	465595	465805
1847	7A	10984	2	607544	607749	465594	465799
807	7A	10845	2	607543	607746	465594	465797
1718	7A	10711	2	607543	607743	465593	465793
1897	7A	10625	5	607543	607742	465593	465792
453	7A	10194	3	607541	607732	465591	465782
370	7A	9893	3	607540	607725	465590	465775
1472	7A	9849	336	607540	607724	465590	465774
1365	7A	9474	2	607538	607715	465589	465766
64	7A	9341	706	607538	607713	465588	465763
549	7A	9043	4	607537	607706	465587	465756
546	7A	8497	237	607535	607694	465585	465744
1504	7A	8095	2	607533	607684	465584	465735
1540	7A	7802	590	607532	607678	465583	465729
1862	7A	7663	2	607532	607675	465582	465725
1435	7A	7532	3	607531	607672	465582	465723
113	7A	7078	535	607529	607661	465580	465712
2042	7A	6990	1	607529	607660	465580	465711
421	7A	6971	1	607529	607659	465579	465709
1505	7A	6771	30	607528	607655	465579	465706
1442	7A	6598	1	607528	607651	465578	465701
196	7A	6507	1	607527	607649	465578	465700
1502	7A	6353	1	607527	607646	465577	465696
79	7A	6336	2	607527	607645	465577	465695

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
1954	7A	5883	1	607525	607635	465575	465685
204	7A	5812	1	607525	607634	465575	465684
220	7A	5722	1	607524	607631	465575	465682
152	7A	5656	1	607524	607630	465575	465681
1438	7A	5225	1	607523	607621	465573	465671
1627	7A	5206	6	607523	607620	465573	465670
476	7A	4900	1	607521	607613	465572	465664
323	7A	4888	82	607521	607612	465572	465663
482	7A	4690	1	607521	607609	465571	465659
1280	7A	4673	1	607521	607608	465571	465658
264	7A	4397	7	607520	607602	465570	465652
1646	7A	4274	0	607519	607599	465569	465649
1317	7A	4235	148	607519	607598	465569	465648
1448	7A	4196	1	607519	607597	465569	465647
1513	7A	3895	52	607518	607591	465568	465641
1191	7A	3591	3	607517	607584	465567	465634
1908	7A	3496	1	607516	607581	465567	465632
1551	7A	3302	1	607515	607577	465566	465628
1444	7A	3275	1	607515	607576	465566	465627
1589	7A	3249	66	607515	607576	465566	465627
346	7A	3147	1	607515	607574	465565	465624
1372	7A	3096	1	607515	607573	465565	465623
354	7A	3035	1	607514	607571	465565	465622
574	7A	3010	1	607514	607570	465565	465621
1453	7A	3010	1	607514	607570	465565	465621
228	7A	3007	3	607514	607570	465565	465621
472	7A	2958	0	607514	607569	465565	465620
1692	7A	2736	1	607513	607564	465564	465615
1370	7A	2720	1	607513	607564	465564	465615
375	7A	2661	1	607513	607563	465563	465613
1807	7A	2578	1	607513	607561	465563	465611
394	7A	2575	1	607513	607561	465563	465611
647	7A	2571	1	607513	607561	465563	465611
1587	7A	2474	6	607512	607558	465563	465609
1503	7A	2311	0	607512	607555	465562	465605
342	7A	2158	0	607511	607551	465562	465602
1595	7A	2152	0	607511	607551	465562	465602
499	7A	2021	0	607511	607549	465561	465599
1396	7A	2013	0	607511	607549	465561	465599
1708	7A	1962	0	607510	607547	465561	465598
8	7A	1802	0	607510	607544	465560	465594
1948	7A	1688	0	607509	607541	465560	465592
1398	7A	1579	0	607509	607539	465559	465589
1393	7A	1578	0	607509	607538	465559	465588
892	7A	1567	0	607509	607538	465559	465588
1895	7A	1458	0	607509	607536	465559	465586
1712	7A	1422	0	607508	607535	465559	465586
387	7A	1364	0	607508	607533	465559	465584
1499	7A	1359	0	607508	607533	465559	465584
1474	7A	1346	0	607508	607533	465559	465584

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
385	7A	1288	0	607508	607532	465558	465582
510	7A	1238	0	607508	607531	465558	465581
344	7A	1237	0	607508	607531	465558	465581
1734	7A	1194	0	607508	607530	465558	465580
101	7A	1177	0	607508	607530	465558	465580
767	7A	1160	0	607508	607530	465558	465580
117	7A	1136	0	607507	607528	465558	465579
257	7A	1111	0	607507	607528	465558	465579
400	7A	1060	0	607507	607527	465558	465578
333	7A	1041	0	607507	607526	465557	465576
1882	7A	1031	19	607507	607526	465557	465576
467	7A	978	0	607507	607525	465557	465575
1397	7A	945	0	607507	607525	465557	465575
231	7A	914	0	607507	607524	465557	465574
1925	7A	895	0	607507	607524	465557	465574
203	7A	844	3	607506	607522	465557	465573
1591	7A	819	0	607506	607521	465557	465572
1392	7A	812	0	607506	607521	465557	465572
1644	7A	781	0	607506	607521	465556	465571
391	7A	733	0	607506	607520	465556	465570
259	7A	698	0	607506	607519	465556	465569
1395	7A	648	0	607506	607518	465556	465568
108	7A	619	0	607505	607517	465556	465568
1974	7A	601	0	607505	607516	465556	465567
806	7A	597	0	607505	607516	465556	465567
1962	7A	585	0	607505	607516	465556	465567
1923	7A	571	0	607505	607516	465556	465567
233	7A	520	0	607505	607515	465556	465566
1880	7A	502	0	607505	607514	465555	465564
112	7A	457	35	607505	607514	465555	465564
292	7A	438	0	607505	607513	465555	465563
1719	7A	438	0	607505	607513	465555	465563
818	7A	435	0	607505	607513	465555	465563
1706	7A	425	0	607505	607513	465555	465563
587	7A	400	0	607505	607512	465555	465562
103	7A	387	0	607505	607512	465555	465562
2018	7A	368	0	607505	607512	465555	465562
545	7A	359	0	607505	607512	465555	465562
116	7A	333	7	607504	607510	465555	465561
1902	7A	298	0	607504	607510	465555	465561
1946	7A	292	0	607504	607509	465555	465560
1257	7A	290	0	607504	607509	465555	465560
17	7A	264	0	607504	607509	465555	465560
1278	7A	256	0	607504	607509	465555	465560
841	7A	254	0	607504	607509	465555	465560
1261	7A	254	0	607504	607509	465555	465560
1876	7A	247	0	607504	607509	465555	465560
1842	7A	213	3	607504	607508	465554	465558
14	7A	210	0	607504	607508	465554	465558
1361	7A	210	0	607504	607508	465554	465558

FID	MODEL	Throughput (bbl/yr)	Emissions (lb/yr)	High Cost to retrofit terminals ($/yr)	High cost to retrofit terminal & vessels ($/yr)	Low cost to retrofit terminal ($/yr)	Low cost to retrofit terminal & vessels ($/yr)
224	7A	203	0	607504	607508	465554	465558
1736	7A	203	0	607504	607508	465554	465558
1607	7A	172	0	607504	607507	465554	465557
1951	7A	165	0	607504	607507	465554	465557
1945	7A	165	0	607504	607507	465554	465557
1947	7A	162	0	607504	607507	465554	465557
480	7A	158	0	607504	607507	465554	465557
1903	7A	153	0	607504	607507	465554	465557
1554	7A	152	0	607504	607507	465554	465557
1465	7A	140	0	607504	607507	465554	465557
1721	7A	127	0	607504	607506	465554	465556
1796	7A	127	0	607504	607506	465554	465556
1477	7A	121	0	607504	607506	465554	465556
218	7A	114	0	607504	607506	465554	465556
656	7A	114	0	607504	607506	465554	465556
160	7A	113	0	607504	607506	465554	465556
1835	7A	108	0	607504	607506	465554	465556
310	7A	102	0	607504	607506	465554	465556
567	7A	95	0	607504	607506	465554	465556
1704	7A	68	0	607503	607504	465554	465555
1500	7A	63	0	607503	607504	465554	465555
1727	7A	63	0	607503	607504	465554	465555
1581	7A	57	0	607503	607504	465554	465555
290	7A	51	0	607503	607504	465554	465555
359	7A	51	0	607503	607504	465554	465555
885	7A	51	0	607503	607504	465554	465555
1960	7A	51	0	607503	607504	465554	465555
538	7A	45	0	607503	607504	465554	465555
126	7A	38	0	607503	607504	465554	465555
1833	7A	38	0	607503	607504	465554	465555
432	7A	32	0	607503	607504	465554	465555
1263	7A	32	0	607503	607504	465554	465555
1702	7A	26	0	607503	607503	465554	465554
1848	7A	25	0	607503	607503	465554	465554
1593	7A	21	1	607503	607503	465554	465554
711	7A	19	0	607503	607503	465554	465554
568	7A	14	0	607503	607503	465554	465554
1703	7A	13	0	607503	607503	465554	465554
261	7A	6	0	607503	607503	465554	465554
339	7A	6	0	607503	607503	465554	465554
1768	7A	6	0	607503	607503	465554	465554
1542	7A	6	0	607503	607503	465554	465554
831	7A	6	0	607503	607503	465554	465554
522	7B	56400943	4674898	1069272	2545256	870341	2346325
571	7B	52989912	1284498	1056680	2443399	857750	2244469
1193	7B	40968480	371377	1012304	2084428	813373	1885497
744	7B	37321375	2162549	998840	1975521	799910	1776591
170	7B	33644250	4141572	985267	1865720	786336	1666789
156	7B	29657459	2459738	970549	1746670	771619	1547740
1059	6A	657000000	86000000	46000000	4728848	34500000	3578848