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Bulk Gasoline Terminals — Background Information for Proposed Standards

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Emission Standards and Engineering Division

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

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ENVIRONMENTAL PROTECTION AGENCY

Background Information
and Draft
Environmental Impact Statement
for Bulk Gasoline Terminals

Prepared by:

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(Date)

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1. The proposed standards of performance would limit emissions of VOC from new, modified, and reconstructed bulk gasoline terminals. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that ". . . causes or contributes significantly to air pollution which may reasonably be 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. Ms. Susan R. Wyatt may be contacted regarding the date of the comment period.

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1.0 SUMMARY

Background information on proposed new source performance standards for the bulk gasoline terminal industry is contained in this document. New source performance standards are proposed under authority of Section 111, 301(a) of the Clean Air Act, as amended.

1.1 REGULATORY ALTERNATIVES

Review of the technical support data led to the development of four regulatory alternatives. Alternative I would require no additional regulatory action. This alternative would rely on the State Implementation Plans (SIP) to regulate bulk terminals primarily in non-attainment areas for ozone. A typical SIP for terminals would limit vapor processor outlet volatile organic compound (VOC) emissions to 80 mg/liter and would require periodic testing of tank trucks for vapor tightness. It is estimated that SIPs will affect about 72 percent of the bulk terminals nationwide by the year 1982.

Alternative II would limit VOC emissions from a bulk terminal's vapor collection system to 80 mg/liter and would require the owner or operator to restrict loadings of gasoline tank trucks to those which had passed an annual vapor-tight test. Even though the emission limit of Alternative II is the same as in the SIPs, greater emission reduction would be achieved because the requirements would be extended to include all areas of the country not regulated by SIPs.

Alternative III would limit VOC emissions from a vapor collection system to 35 mg/liter. This alternative would rely on the SIPs to control tank truck vapor leakage in most areas of the country.

Alternative IV would also limit vapor collection system emissions to 35 mg/liter, but would require a terminal owner or operator to restrict loadings of gasoline tank trucks to those which had passed an annual vapor-tight test. This alternative would extend the tank truck vapor-tight requirement to previously unregulated areas of the country.

1.2 ENVIRONMENTAL IMPACTS

Under Alternative I, there would be no VOC emission reduction from baseline emission levels because there is no additional regulatory action associated with Alternative I. Under Alternative II, nationwide VOC emissions would be reduced by 5,750 Mg/year by 1985. This represents a reduction of about 60 percent in the VOC emissions from all new, modified, or reconstructed terminals, and a reduction of approximately 4 percent in the emissions from all bulk gasoline terminals.

Under Alternative III, nationwide VOC emissions would be reduced by 4,510 Mg/year by 1985, a reduction of about 50 percent in the emissions from affected terminals and a reduction of about 3 percent in emissions from all bulk gasoline terminals. The lower emission reduction of Alternative III when compared to Alternative II illustrates the significance of tank truck vapor leakage. Even though processor outlet emissions under Alternative III would be reduced from 80 mg/liter to 35 mg/liter, the lack of vapor-tight testing requirements for tank trucks in attainment areas more than offsets the additional processor outlet VOC reduction.

Under Alternative IV, nationwide VOC emissions by 1985 would decrease by 6,620 Mg/year. This represents a reduction of about 70 percent in the nationwide VOC emissions from affected terminals, and a reduction of about 5 percent for all bulk gasoline terminals.

The regulatory alternatives would result in negligible impacts on noise, space, and availability of resources.

The air quality impacts, as well as all environmental impacts, are summarized in Table 1-1.

None of the control systems evaluated uses water as a collection medium. Some control systems handle small amounts of water removed from the air; however, all product is removed in a gasoline/water separator. The impact on water quality would be small.

No solid waste is directly generated by any system evaluated. An indirect solid waste impact may be encountered by the disposal of spent activated carbon from carbon adsorption control systems. Even in the worst case, where all systems used were carbon units and where

TABLE 1-1. ASSESSMENT OF ENVIRONMENTAL AND ECONOMIC IMPACTS FOR EACH REGULATORY ALTERNATIVE CONSIDERED

Regulatory Alternative	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Noise Impact	Economic Impact	Inflationary Impact
I	0	0	0	0	0	0	0
II	+2**	-2*	-1**	+2**	-1*	-1*	-1*
III	+2**	-2*	-1**	+2**	-1*	-1*	-1*
IV	+3**	-2*	-1**	+3**	-1*	-1*	-1*

Key:

+	Beneficial Impact	3	Moderate Impact
-	Adverse Impact	4	Large Impact
0	No impact	*	Short-Term Impact
1	Negligible Impact	**	Long-Term Impact
2	Small Impact	***	Irreversible Impact

the carbon was discarded after its useful life at the terminal, the solid waste impact would be minimal.

Energy impacts were derived by assuming that all VOC reduction would be recovered as liquid product and that this product is equivalent to gasoline. Positive energy impacts would be realized with each alternative even when it is assumed that as many as half of the small terminals could use thermal oxidation systems which do not recover any product. Fuel savings by 1985 could be as much as 9 million liters of gasoline per year under Alternative IV.

1.3 ECONOMIC IMPACTS

The total capital cost to the bulk gasoline terminal industry for the installed vapor control equipment necessary to meet Alternative II on all new, modified, or reconstructed terminals would be approximately $23.0 million through the first five years of the standard. The terminal industry annualized cost in 1985 would be $3.3 million. The total capital cost to the for-hire tank truck industry by 1985 would be about $1.3 million, and the annualized cost to this industry in 1985 would be $0.7 million. The total annualized cost for these two industries, coupled with the annual emission reduction expected under Alternative II, would yield an annualized cost-effectiveness of $696/Mg ($632/ton) of VOC controlled.

The total capital cost for vapor control equipment necessary through the first five years to meet Alternative III would be approximately $24.0 million. The terminal industry annualized cost which would be experienced in 1985 would be $4.1 million. The total capital cost to the for-hire tank truck industry would be the same as under Alternative II, and the annualized cost in 1985 would be $0.6 million. The total annualized cost to both industries, coupled with the emission reduction expected under Alternative III, would yield an industry annualized cost-effectiveness in 1985 of $1,042/Mg ($946/ton) of VOC controlled.

The total capital cost for vapor control equipment necessary through the first five years of the standard to meet Alternative IV would be approximately $24.0 million. The industry annualized cost which would be experienced in 1985 would be $3.6 million. Total capital and annualized costs to the for-hire tank truck industry would be the same as under Alternative II. The total annualized cost to both industries, coupled with the emission reduction expected under Alternative IV, would result in an annualized cost-effectiveness in 1985 of \$650/Mg (\$590/ton) of VOC controlled.

Capital availability should not be a limiting factor in the attempt of the smaller new bulk gasoline terminals to comply with the proposed standards. Terminals in the smaller size range would have to pass through most of the control costs to remain reasonable investments. The necessary degree of cost pass-through appears possible. The larger terminals are considered attractive investment possibilities. Consequently, industry growth, considering that principally the larger terminals are most likely to be constructed in the absence of new standards, would not be restricted by implementation of any regulatory alternative.

Existing top loaded terminals in attainment areas, of medium throughput, would have to pass through most of their control costs in order to maintain a reasonable rate of return under any alternative. As in the case of the smallest terminals, most of the control costs should be able to be passed through. The current trend toward the consolidation of existing facilities of marginal profitability is expected to continue, but no additional closures are projected to result due to any of the alternatives.

The cost pass-through analyses for both new and existing terminals show that the maximum retail price increase for gasoline would be less than 0.6 percent under any alternative. This represents a worst case situation within the bulk terminal industry, and nationwide gasoline prices would not be affected.

The regulatory alternatives would affect the independent tank truck industry with minor impacts. The profitability of the firms in the industry would not be impacted significantly since regulatory cost absorption would be minimal. Most of the regulatory costs would be passed through to the consumer, causing a maximum increase in retail gasoline prices of less than 0.05 percent for any of the alternatives. This increase would not affect nationwide gasoline prices, but represents a worst case situation within the independent tank truck industry if all control costs were passed through. Additionally, no closures or dislocations of tank truck firms are expected to result from any of the regulatory alternatives.

2.0 INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are expressed as regulatory alternatives. Each of these alternatives is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be able to see the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C 7411) as amended, hereinafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which "... causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect, "... the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the <u>Federal Register</u>.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources that have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

a. 25 percent of the listed categories by August 7, 1980.

b. 75 percent of the listed categories by August 7, 1981.

c. 100 percent of the listed categories by August 7, 1982.

A governor of a State may apply to the Administrator to add a category not on the list or may apply to the Administrator to have a standard of performance revised.

2. EPA is required to review the standards of performance every four years and, if appropriate, revise them.

3. EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

4. The term "standards of performance" is redefined, and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under Section 111 of the Act may be extended to six months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term Best Available Control Technology (BACT), as defined in the Act, means

> ... an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best

> available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Section 111 or 112 of this Act. (Section 169(3))

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(j) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic energy or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to three years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Administrator to list categories of stationary sources. The Administrator "... shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as: (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are: (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases, it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the non-air quality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources, and a literature search is conducted. From the knowledge acquired about the industry, EPA selects certain plants at which emission tests are conducted to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "regulatory alternatives." These regulatory alternatives are essentially different levels of emission control.

EPA conducts studies to determine the impact of each regulatory alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possibly applicable alternatives, EPA selects the single most plausible regulatory alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected regulatory alternative is translated into a standard of performance, which, in turn, is written in the form of a federal regulation. The federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected regulatory alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control

Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the Background Information Document (BID). The BID, the standard, and a preamble explaining the standard are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D. C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and EPA's position on the issues raised are included in the "preamble" of a "promulgation package," which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an economic impact assessment with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of:

(1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small business with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may cause water pollution problems, and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decision-making process of federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Clean Air Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969." (15 U.S.C. 793(c)(1))

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by Section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate Section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as "... any stationary source, the construction or modification of which is commenced..." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111(d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by an industry may improve with technological advances. Accordingly, Section 111 of the Act provides that the Administrator "... shall, at least every 4 years, review and, if appropriate, revise..." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3.0 THE BULK GASOLINE TERMINAL INDUSTRY

3.1 GENERAL

3.1.1 Introduction

A bulk gasoline terminal is typically any wholesale marketing facility which receives gasoline from refineries by pipeline, ship, or barge; stores it in large aboveground tanks; and dispenses it into tank trucks for delivery to customers. Only a small number (less than 2 percent) of bulk terminals dispense gasoline into rail cars. Gasoline is delivered from bulk terminals to smaller bulk facilities, known as bulk plants, or directly to retail accounts. Typically, bulk plants have throughputs less than 76,000 liters (20,000 gallons) per day while terminals typically have throughputs greater than 76,000 liters per day. Terminals handle several petroleum products in addition to gasoline, including diesel fuel and heating oil.

For the purpose of this study, gasoline is defined as a petroleum distillate or a petroleum distillate/alcohol blend having a Reid Vapor Pressure of 27.6 kPa (4 psi) or greater that is used as fuel for internal combustion engines. Gasoline is by far the largest volume petroleum product marketed in the U.S., with a nationwide consumption of 443 billion liters (117 billion gallons) in 1978.[1] Since the major use for gasoline is the fueling of the passenger automobile, the demand for gasoline is assured as long as automobiles are the primary means of transportation in the country. Other uses for gasoline include light-duty trucks, motorcycles, power boats, and small devices such as electrical generators and lawn mowers. Expected future trends in gasoline consumption and in the size of the bulk gasoline terminal population are discussed in Section 8.1 of Chapter 8.

3.1.2 Terminal Locations and Sizes

There are presently an estimated 1,511 bulk terminals storing gasoline in the U.S.[2] About half of these terminals receive products from refineries by pipeline, and half receive products by ship or barge delivery. Most of the terminals (66 percent) are located along the east coast and in the Midwest. The remainder are dispersed throughout the country, with locations largely determined by population patterns.

The combined gasoline storage capacity of all the terminals is approximately 47 million cubic meters (m^3), with the largest segment of the terminal population being composed of smaller facilities (less than 32,000 m^3 capacity). The average gasoline throughput, or business volume, of all terminals is approximately 2 million liters per day.[3]

3.2 GASOLINE LOADING OPERATIONS AND THEIR EMISSIONS

3.2.1 Introduction

Bulk gasoline terminals serve as redistribution points for the gasoline produced at refineries and, as such, they do not perform any processing operations on the gasoline, although sometimes additives are mixed with gasoline at terminals. All movement of gasoline at a bulk terminal involves only loading, unloading, and transfer. Gasoline stored in tanks is pumped through metered loading areas, called loading racks, and into delivery tank trucks, which service various wholesale and retail accounts in the marketing network. Figure 3-1 shows a schematic diagram of the transfer of gasoline at a bulk terminal. The following section describes in more detail the major components in terminal loading operations.

3.2.2 Gasoline Loading at Bulk Terminals

3.2.2.1 Storage Tanks. A typical terminal has four or five aboveground storage tanks for gasoline, each with a capacity ranging from 1,500 to 15,000 m^3 (9,400 to 94,000 barrels). Most tanks in gasoline service have a floating roof to prevent the loss of product through evaporation and working losses. Fixed roof tanks use pressure-vacuum (P-V) vents to control breathing losses and use vapor balancing or processing equipment to control working losses.

A new source performance standard (NSPS) has been promulgated for controlling the escape of hydrocarbon vapors from storage vessels for petroleum liquids.[4] Thus, emissions from gasoline storage tanks will not be discussed further.

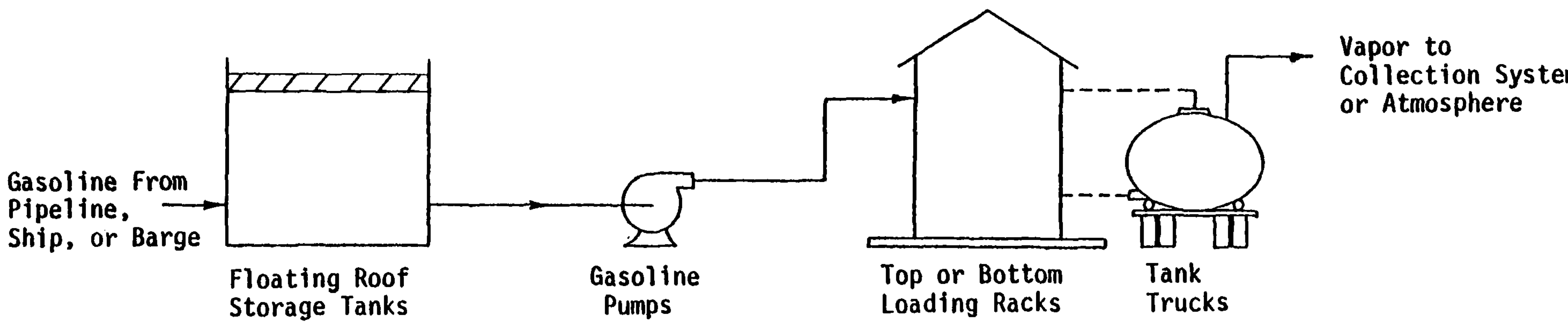


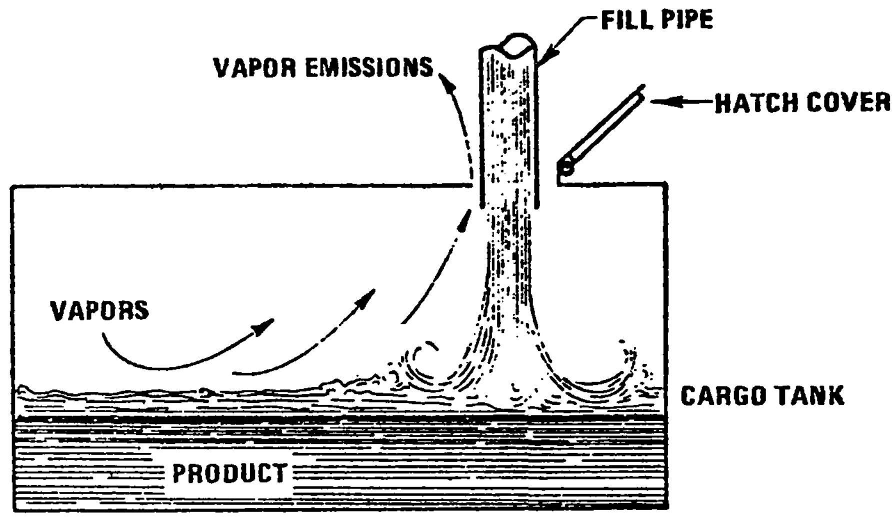
Figure 3-1. Example of Gasoline Loading at Bulk Terminals

3.2.2.2 Loading Racks. Loading racks contain the equipment necessary to fill delivery tank trucks with liquid product. A typical loading rack includes fuel loading arms, pumps, meters, shutoff valves, relief valves, check valves, electrical grounding, and lighting. Terminals generally utilize two to four rack positions for gasoline, each having from one to four loading arms. Gasoline is loaded through a loading arm at an average rate of 2,270 liters per minute (600 gpm), with the rate at various terminals ranging from 1,320 liters per minute (350 gpm) to 3,790 liters per minute (1,000 gpm). Loading may be performed using either top splash, top submerged, or bottom loading methods. These systems will be discussed in greater detail in the following subsections.

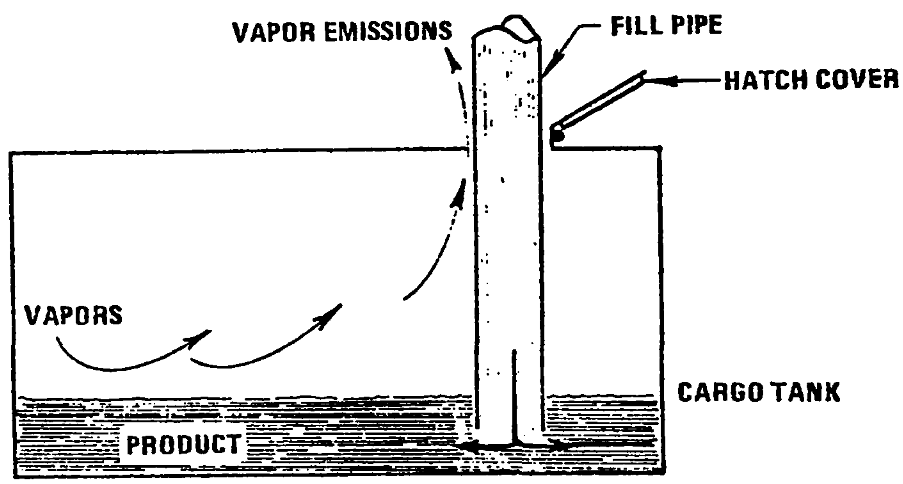
3.2.2.2.1 Top loading. Top loading is divided into top splash loading, with and without vapor collection, top submerged, and top tight submerged loading. Top loading involves loading of products into the compartment via the hatchway which is located on top of the tank. Gasoline is loaded directly into the compartment through a top loading fill pipe (splash fill). Attachment of a fixed or extensible downspout to the fill pipe provides a means of introducing the product near the bottom of the tank (submerged fill). Top splash loading creates more turbulence during loading and can create a vapor mist. Submerged loading greatly reduces the turbulence. See Figure 3-2.

Top loading can also be designed for vapor collection. A top loading vapor head, compatible with the truck hatch opening, creates a vapor-tight seal between the loading head and the hatch to minimize vapor leakage during transfer of product. An annular space in the vapor head routes vapors into the vapor collection system. See Figure 3-3.

In a top tight submerged fill installation, the loading of product is performed through a vapor-tight loading adapter mounted on top of each compartment and attached to a permanently fixed submerged fill pipe. For vapor collection, the vapor spaces of each compartment are routed to the overturn rail or to a vapor return line. Vapors from all compartments are manifolded together into one vapor line. Figure 3-3 shows one of these configurations. One advantage of this permanently affixed top tight submerged fill system is that the hatch/dome covers remain closed at all times except for cleanup and repair.

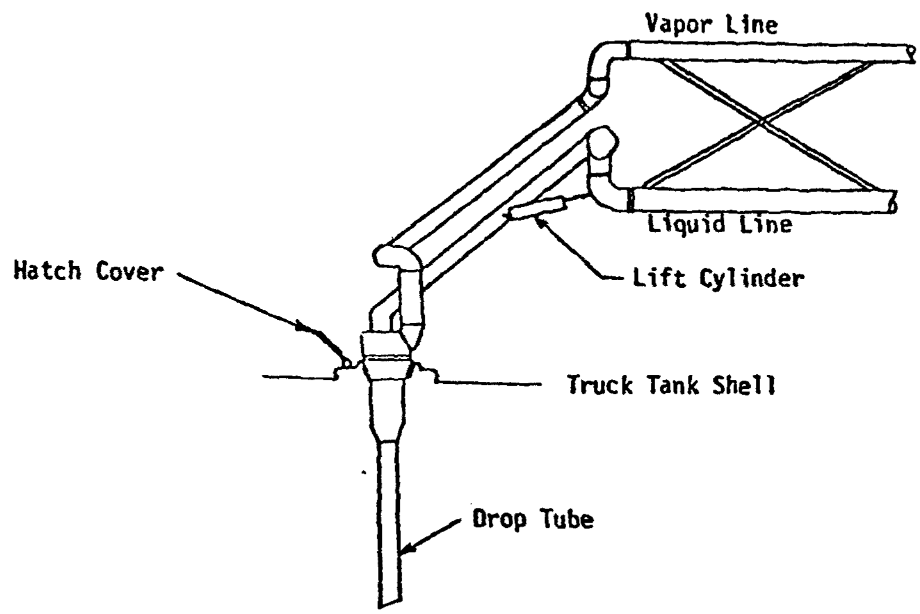


a. Top Splash Loading

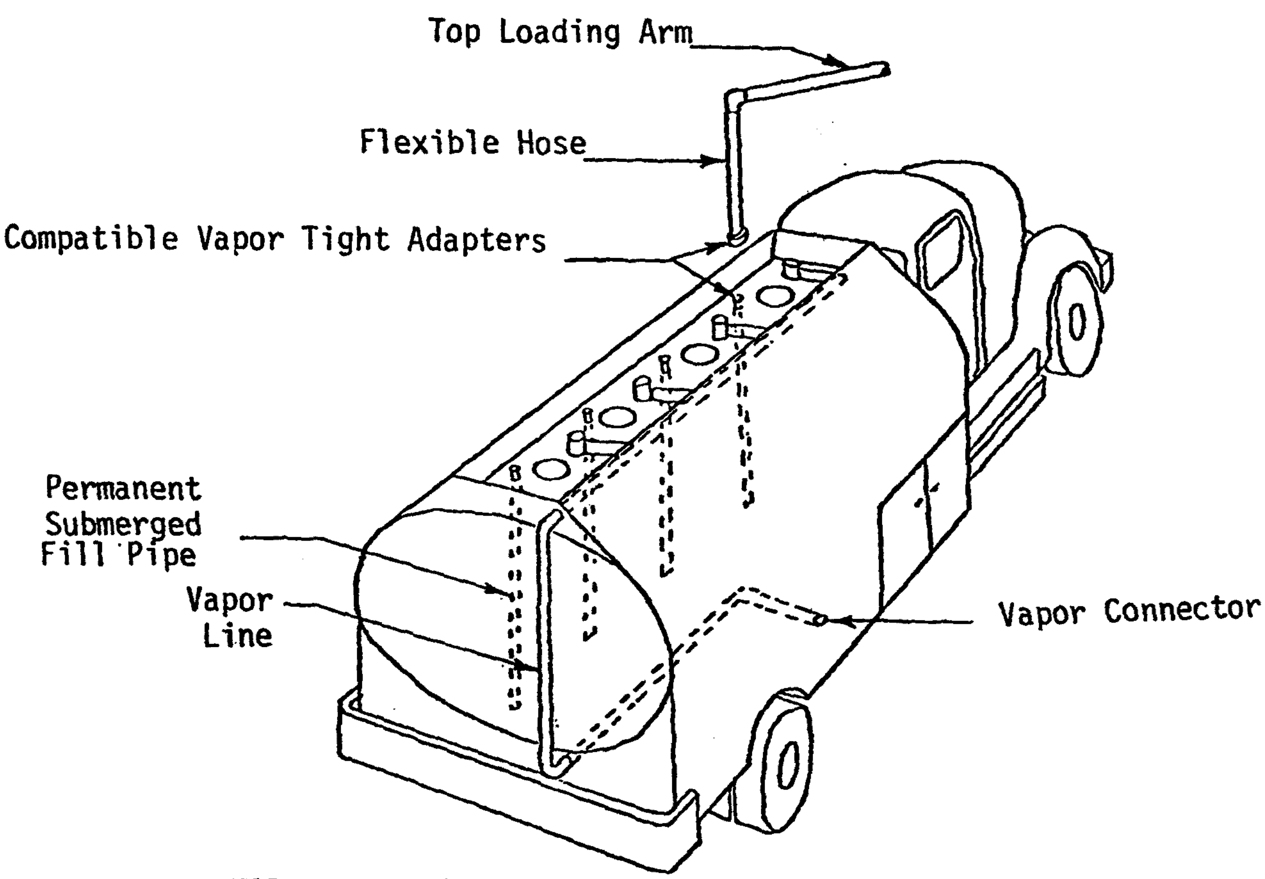


b. Top Submerged Loading

Figure 3-2. Top Loading Methods Without Vapor Collection



TOP LOADING VAPOR HEAD SYSTEM



TOP TIGHT LOADING SYSTEM

Figure 3-3. Top Loading Systems With Vapor Collection

This minimizes wear on the hatch and vapor containment equipment. The top tight and vapor head systems allow the collection of vapors expelled from the tank during product loading.

The top tight loading system is not in widespread use at terminals. Simplified loading combined with vapor collection is generally accomplished using bottom loading, which is described in the following section.

3.2.2.2.2 Bottom loading. Bottom loading refers simply to the loading of products into the cargo tank from the bottom. Figure 3-4 illustrates the principle of bottom loading. Submerged loading occurs naturally using this method and turbulence is again held to a minimum. Some of the advantages cited for bottom loading include: (1) improved safety, (2) faster loading, and (3) reduced labor costs. Safety is improved since the operator does not have to climb on top of the truck. This is especially advantageous during wet or icy conditions when the top of the truck may be slick. Loading can be accomplished in a shorter time because all the equipment is at ground level where it can be easily handled by the operator. Faster loadings reduce labor costs because more loadings can be done per labor-hour.

Loading gasoline into a tank truck through bottom connectors is a simple operation. Dry-break couplers are used to attach loading arms to trucks so that liquid loss can be minimized during connecting and disconnecting. For vapor collection, a flexible hose or swing-type arm is usually connected to a vapor collection line on the truck. This line routes gasoline vapors to a vapor collection and processing system. See Figure 3-5.

3.2.2.2.3 Overfill protection. In order to measure the quantity of gasoline delivered during bottom loading and to provide protection against overfilling, set-stop meters are used to shut off the flow of gasoline when a preset quantity has been delivered. Liquid level sensing devices are commonly used with preset meters to provide secondary control in the event of a malfunction or human error. Liquid level sensors are devices used to detect a full condition in the compartment being loaded. These devices are electrically connected to close flow control valves or shut off the delivery pumps if the level approaches the top of the tank. This eliminates the possibility of

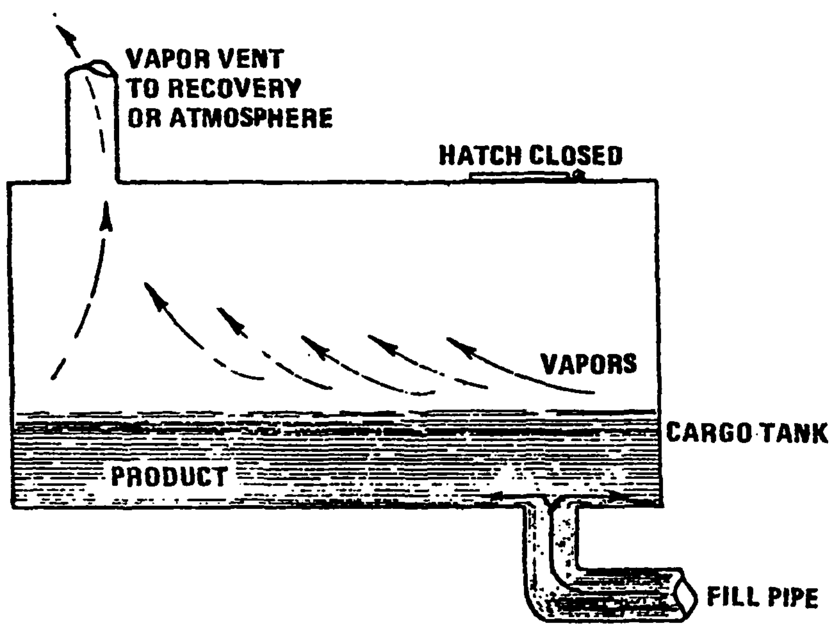


Figure 3-4. Bottom Loading

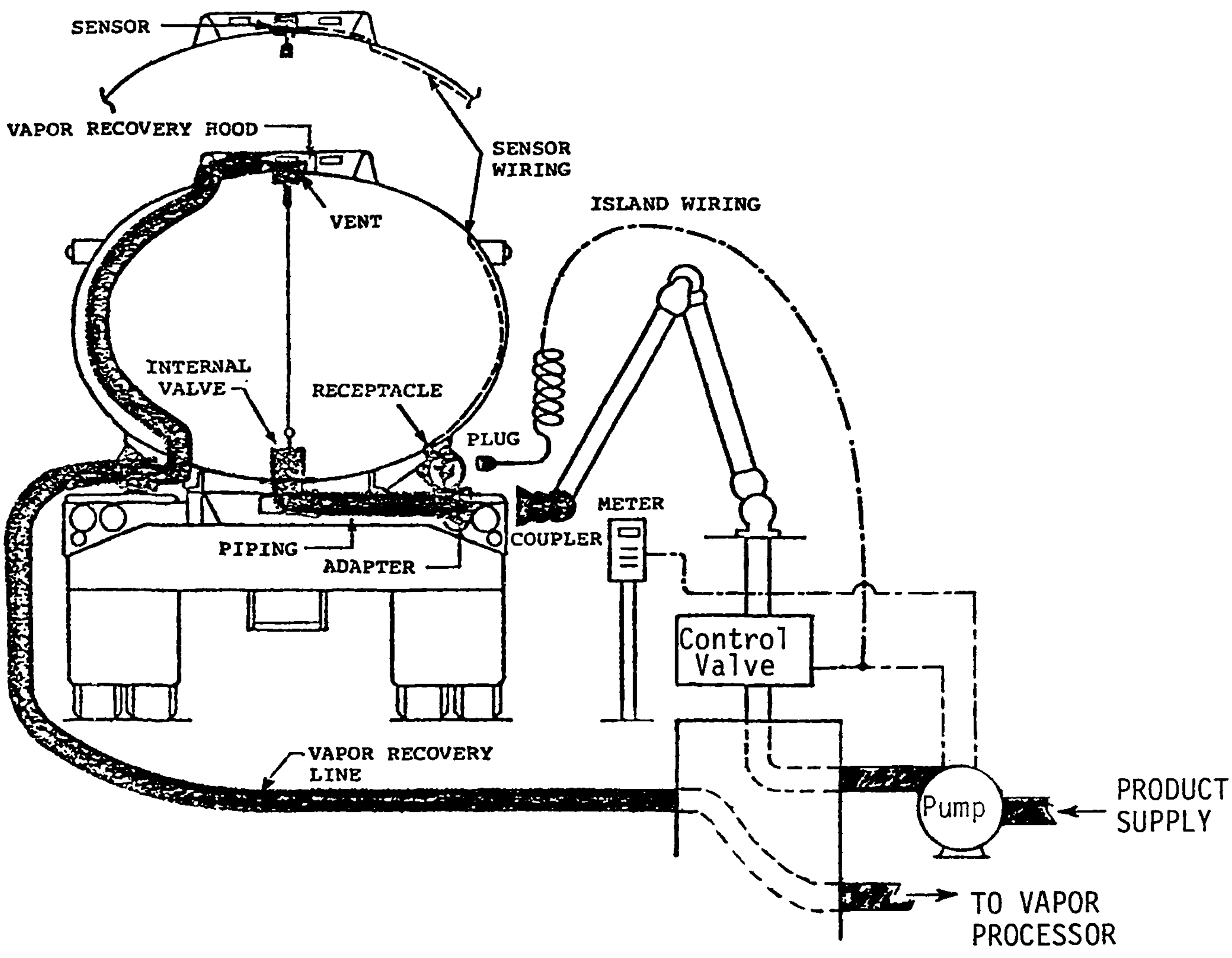


Figure 3-5. Typical Bottom Loading System With Vapor Collection

overfilling the compartment. Commonly used sensing devices include fiber optics systems, electric probe, and float switches.

3.2.2.3 Tank Trucks. Oil companies operating bulk terminals typically operate from 3 to 20 gasoline tank trucks at a single terminal, although many terminals are served entirely by "for-hire" tank trucks operated by outside companies. These tank trucks range in size from 15,000 to 38,000 liters (4,000 to 10,000 gallons), averaging about 32,200 liter (8,500 gallon) capacity.[5] While there are several configurations of delivery tank vehicles in service, the single term "tank truck" will generally be used throughout this document to include all of them. Model firms for the for-hire tank truck industry are discussed in Section 6.2.5, and an industry profile and economic impact analysis for this industry are contained in Sections 8.1.3 and 8.4.2 of Chapter 8.

Just as there are several loading methods and types of rack equipment to fill tank trucks with gasoline, there are several compatible truck loading systems. Tank trucks are normally divided into compartments with a hatchway at the top of each compartment. Top loading can be accomplished by opening the hatch cover and dispensing product directly through the hatch by splash or submerged fill. A top loading vapor head compatible with the hatch also permits loading through the hatch while vapors are collected. A better vapor-tight seal is realized when top loading is performed through a top tight loading adapter mounted in each compartment.

During a bottom loading operation, an internal valve is opened to allow product flow, and tank vents open to permit the exit of vapors which are displaced by the incoming product. Vapor collection systems on tank trucks incorporating bottom loading equipment collect vapors from the compartment vents through a common vapor manifold. The tank truck vapor line terminates at a connector on the side or at the rear of the truck which is compatible with the terminal vapor collection equipment.

A recent survey[6] covering approximately 1,900 tank vehicles, or about 2 percent of the gasoline tank truck population, indicated that

22.8 percent of tank trucks have only top loading, while the remaining 77.2 percent can be either top or bottom loaded. The trend is toward more trucks using bottom loading, due to State vapor recovery regulations and the advantages cited earlier.

3.2.3 Emissions From Loading Operations

Since there are no other processes associated with the loading of gasoline into tank trucks at bulk terminals, the only emissions from the operation are volatile organic compounds (VOC) consisting of the gasoline vapors displaced from tank trucks during loading. These compounds are primarily C_4 and C_5 paraffins and olefins which are photochemically reactive (precursors to ozone). Table 3-1 presents an example of the major components of the air-vapor mixture emitted during the loading operation. The exact composition depends on the particular gasoline being loaded and the vapor concentration in the tank.

3.2.3.1 Switch Loading. It was mentioned earlier (Section 3.1.1) that bulk gasoline terminals may handle liquid petroleum products other than gasoline. VOC emissions from products such as fuel oil, diesel, and jet fuel can be considered negligible when compared to gasoline, because of the lower vapor pressures of these products. The emissions from the loading of these products are 0.02, 2.4, and 3.6 milligrams, respectively, for each liter of product loaded.[7] The emission factors for the loading of gasoline are discussed in the next section. At many terminals, "switch loading" of delivery tank trucks is practiced. Switch loading involves the transport, in a single tank compartment on successive deliveries, of one or more other products in addition to gasoline. Gasoline vapors can be displaced either by incoming gasoline or by any other liquid product when vapors from a previous load of gasoline are left in the delivery tank. As an example, fuel oil loaded into a tank compartment which had carried gasoline on the previous load would displace gasoline vapors, producing VOC emissions. Thus, VOC emissions can occur at gasoline loading racks, and also at product loading racks which switch load into tank trucks which transport gasoline.

Table 3-1. EXAMPLE AIR-GASOLINE VAPOR MIXTURE COMPOSITION[8]

Component	Volume Percent
Air	74.5
N-Butane	12.2
Iso-Pentane	6.5
Iso-Butane	3.0
N-Pentane	2.5
Butene	0.5
Propane	0.4
Hexane	0.3
Benzene	0.1
Total	100.0

Without emission controls on the loading operation, the quantities of VOC emitted depend on such factors as the loading method used and the concentration of the vapors in the tank truck at the start of loading. These factors are discussed in the following subsection.

3.2.3.2 Factors Affecting Emissions. When gasoline is loaded, the rate of emission of VOC is affected by the manner in which the gasoline is introduced into tank trucks. Top splash loading creates a turbulent loading operation which causes the entrainment of gasoline mist and droplets in the vapor space. The mist and droplets are subsequently emitted to the atmosphere through the open hatches. The emissions for uncontrolled splash loading are 1,440 milligrams of VOC emitted for each liter of gasoline loaded (mg/liter) (12 pounds/1000 gallons).[7] For submerged fill or bottom loading the emissions are reduced to 600 mg/liter (5 pounds/1000 gallons). These factors apply to normal service, in which tank trucks do not exchange gasoline for air-vapor mixture when unloading at bulk plants or retail accounts.

The emissions from loading trucks in "balance service" are affected by the concentration of vapors in the tank air space during loading. "Balance service" applies to tank trucks which have exchanged their liquid gasoline for the vapors displaced by filling the gasoline storage tanks at the service station or bulk plant. The amount of vapors exchanged depends upon the vapor tightness of the tank truck. If leaks occur, air enters the compartment and the amount of vapors transferred, and hence the concentration in the compartment, decreases. VOC vapor levels may approach saturation in a tank truck servicing delivery points where a vapor balance system is utilized. The emissions for both splash fill and bottom loading of tank trucks in balance service are 960 mg/liter (8 pounds/1000 gallons).[7] The requirement for vapor balancing of tank trucks is expected to be in effect by the end of 1982 in areas where bulk terminals are regulated by SIPs.

Table 3-2 presents the uncontrolled VOC emissions from terminals in selected size ranges. The data indicate that these emissions from terminals are generally greater than 100 Mg/year.

3.2.3.3 Vapor Collection at Loading Racks. In open top loading without vapor recovery the displaced air-vapor mixture escapes to the

Table 3-2. UNCONTROLLED VOC EMISSIONS FROM BULK GASOLINE TERMINALS

Gasoline Throughput	Splash Loading[a] Mg/yr	Splash Loading[a] Ton/yr	Submerged Loading[b] Mg/yr	Submerged Loading[b] Ton/yr	Balance Service[c] Mg/yr	Balance Service[c] Ton/yr
380,000 liters/day (100,000 gal/day)	185	205	80	85	125	135
950,000 liters/day (250,000 gal/day)	465	510	195	215	310	340
1,900,000 liters/day (500,000 gal/day)	930	1,020	390	425	620	680
3,800,000 liters/day (1,000,000 gal/day)	1,860	2,040	775	850	1,240	1,360

[a]Emission Factor = 1,440 mg/liter.

[b]Emission Factor = 600 mg/liter. Pertains to top submerged and bottom loading.

[c]Emission Factor = 960 mg/liter. Pertains to top or bottom loading, and represents a delivery tank whose previous load was balanced with displaced vapors during filling of a bulk plant or service station storage tank.

atmosphere through the open hatchway. The emission factors for uncontrolled emissions discussed earlier apply to this type of loading. The other types of loading include provisions for recovering the vapors so that they can be processed (destroyed or condensed into liquid product). The emissions from such controlled loading depend on the control efficiency of the vapor processor and the amount of leakage in the vapor collection system.

The flexible hoses or swing-type arms at the loading racks, which collect air-vapor mixture from loading tank trucks, are manifolded together and all of the collected vapors are piped to a single vapor processor. In the case where two tank trucks are loading simultaneously at different racks, it is possible for the air-vapor mixture displaced from one tank to pass through the vapor piping and escape through the other tank. This phenomenon has been observed in several terminal tests. To avoid this problem, most bulk terminals install check valves or similar devices in the vapor return lines to isolate individual lines and ensure that vapors are routed to the vapor processor. The processors which are in current usage are discussed in Chapter 4. Acceptable collection efficiency of controlled loading operations depends on the absence of vapor leaks in the system. The following subsections describe several places in the collection system where fugitive (leakage) emissions can occur.

3.2.3.3.1 Tank truck leakage. The effectiveness of vapor control systems at bulk terminals is dependent upon the minimization of leaks in the vapor-containing equipment. Some gasoline delivery tank trucks have been demonstrated to be major sources of vapor leakage during loading operations. The average vapor leakage from delivery tanks measured in EPA-sponsored terminal tests was found to be 30 percent. These tests were performed in areas having no tank truck vapor tightness regulations. Vapor leakage as high as 100 percent for individual tank loadings was recorded.[9] In contrast, the average leakage in an area of California requiring vapor tightness certification testing was found to be 10 percent.[10] Sources of leakage include dome covers, pressure-vacuum (P-V) vents, and vapor collection piping and vents.

Dome cover assemblies consist of a series of openings, clamps, and seals, each of which is a potential source of VOC vapor leakage. Leakage can occur when foreign material becomes lodged in the interface between the hatchway collar and the dome base ring or between the base ring and the dome lid. The normal vibration of these components during product transport may also lead to gradual seal failure. In addition, the dome lid can become warped or damaged if it is opened and closed frequently, or if struck by a top loading arm.

P-V vents are normally installed in the dome lids to prevent dangerous pressure differentials from damaging the tanks. Dome lids are spring-loaded to serve as backup pressure release to the P-V vents installed in the lids. Emissions may occur if a P-V vent is not installed correctly or the valve seat is damaged or dirty and is not sealing properly. Figure 3-6 illustrates the primary sources of leakage for a typical configuration.

On those truck delivery tanks which have vapor recovery equipment installed, VOC can leak from the vapor collection equipment. Normally, each compartment has a vent valve which is opened when that compartment is being loaded or unloaded. This vent allows vapors to be removed from or returned to the compartment through piping in the vapor collection system. The compartment vent valve is covered with either a rubber boot assembly or a metal cover, bolted or welded in place, to contain the vapors in the vapor transfer system. The vapor return line can be either rubber hose or metal pipe mounted on top of the tank or incorporated into the overturn rail, or any combination of these. The vapor return line, which is manifolded to each compartment, contains joints or connectors in the piping for each compartment.

VOC vapors can leak from the vent valve cover due to tears in the rubber boot, leaks in gaskets at bolted covers, or faulty welds in welded covers. Leaks can occur in the vapor line connectors from poor seals or clamping mechanisms with rubber hoses, or faulty welds or seals with metal piping. VOC emissions may also be detected at the vapor return coupler. This is caused by vapors leaking out through the vapor transfer lines due to improperly sealing internal valves.

Other sources of vapor leakage on tank trucks which occur less frequently than those already discussed include tank shell flaws,

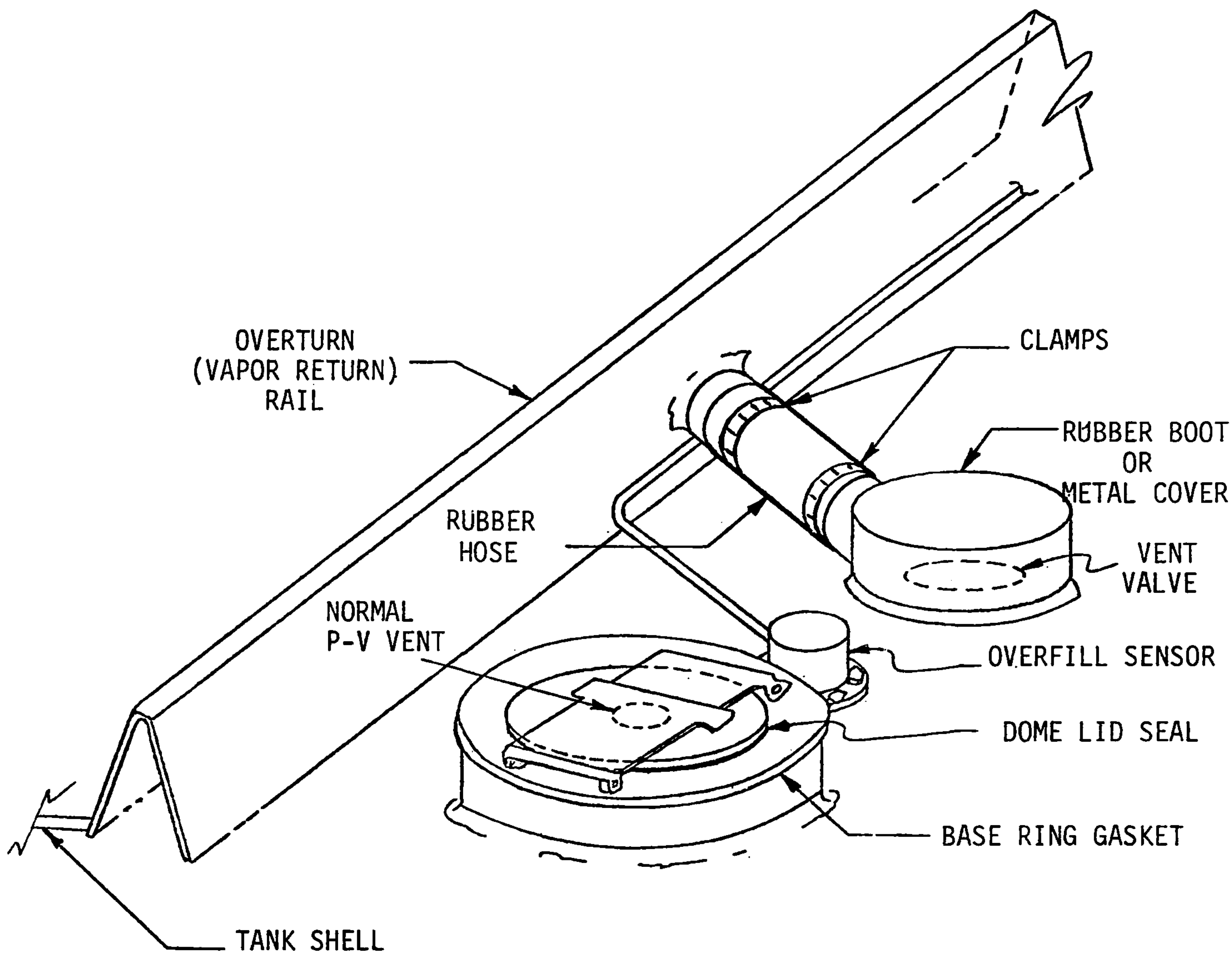


Figure 3-6. Major Tank Truck Leakage Sources

improperly welded seams, and improperly installed or loosened overfill protection sensors.

3.2.3.3.2 Vapor collection system leakage. The most common leakage points in a vapor collection system include vapor connectors and hoses, interfaces between top loading vapor recovery heads and tank hatch openings, and vapor piping to control units.

Leakage occurs from connectors and hoses when they are improperly connected or are allowed to deteriorate to a highly worn condition. Vapor piping can leak due to faulty flange gaskets or accidental damage. P-V vents on knockout (condensate) tanks and vapor holders can also be sources of leakage in the vapor collection system. In one EPA test, approximately 81 percent of the displaced vapors leaked from a vapor holder before reaching the processor,[11] and in another EPA test about 48 percent of the vapors escaped from leaks in tank trucks and loading rack P-V vents and check valves.[12]

For top loading vapor collection systems, a significant source of leakage is the interface between the top loading vapor head and the tank truck hatch. The vapor heads are designed to seal at the hatch through the compression of a cone-shaped rubber ring. However, in practice these vapor heads do not seal consistently at the hatch interface and can be a sizeable source of leaks.[10]

3.2.4 Gasohol

There is a growing worldwide interest, both in the developing countries and the more affluent industrialized nations, in the use of gasohol.[13] At present, Brazil is pursuing the most ambitious alcohol fuel program.[14] A large percentage of most current publications deal with political issues,[15,16] cost-effectiveness, and alternative processes for increasing alcohol production, in addition to the effects of gasohol on automobile operation.

3.2.4.1 Gasohol Market Trends. Current market reports (August 1980) indicate that gasohol, primarily because of weak gasoline prices and high alcohol prices from primary suppliers, is having difficulty in maintaining a competitive edge. For example, one large chain, which found gasohol accounting for 12 to 15 percent of total sales in 1979, when it could price the product at 2 cents per gallon over unleaded gasoline, now finds the ratio as low as 5 percent because of a 6 cent per gallon differential over unleaded.[17]

One of the major factors which will determine whether alcohol fuels will remain competitive is the number of States which will set tax exemptions for gasohol. So far, only 17 States have offered exemptions and just 9 of these provide substantial financial advantages. The other eight offer nominal reductions or reductions for alcohol produced only in those States. While some States have sacrificed substantial tax revenues to help gasohol become a staple in the marketplace, four-fifths of the States have not made such commitments. These tax advantages are essential if gasohol is to survive until alcohol production is sufficient to moderate or even reduce prices.[18]

3.2.4.2 Properties of Gasohol. Gasohol is an automotive fuel which contains 10 volume percent ethanol and 90 volume percent gasoline. A profile of the properties of gasohol may prove useful in considering the potential effect of gasohol on the operation of vapor control systems. Gasoline is composed of several hydrocarbon constituents and contains less than 1 percent of elements other than hydrogen and carbon. Ethanol, CH_3CH_2OH, contains almost 35 percent oxygen. A few of the pertinent properties of ethanol and gasoline are listed in Table 3-3.

The Reid Vapor Pressure (RVP) of gasoline will increase due to the addition of 10 percent ethanol from approximately 8.7 psia to 9.8 psia. As a result, evaporative emissions from gasohol are approximately 50 percent higher than those from straight gasoline, even with blend and gasoline matched in vapor pressure.[20]

Ethanol is completely miscible with water as well as with gasoline; a small amount of water can be tolerated in gasohol. However, less than 1 percent water at ambient temperatures or lower will result in separation of the phases, with the ethanol concentration higher in the water phase. This water phase is less dense than pure water and can be corrosive to steel, aluminum, or zinc.

Additional properties include the cleansing effect of gasohol. Gum, varnish, sediment, and rust can be loosened and suspended by the gasohol, which in automobiles may result in the clogging of the fuel filter.[19]

Table 3-3. PROPERTIES OF ETHANOL AND GASOLINE[19]

CHEMICAL PROPERTIES	Gasoline	Ethanol
Formula	C_4-C_{12}	CH_3CH_2OH
Molecular Weight	varies	46.1
% Carbon (by weight)	85-88	52.1
% Hydrogen (by weight)	12-15	13.1
% Oxygen (by weight)	indefinite	4.7
PHYSICAL PROPERTIES	**Gasoline**	**Ethanol**
Specific Gravity	0.70-0.78	0.794
Liquid Density lb/ft^3	43.6 approx.	49.3
lb/gal	5.8-6.5	6.59
psi at 100°F (Reid)	7-15	2.5
psi at 77°F	0.3 approx.	0.85
Boiling Point (°F)	80-440	173
Freezing Point (°F)	-70 approx.	-173
Solubility in Water	240 ppm	infinite
THERMAL PROPERTIES	**Gasoline**	**Ethanol**
Lower Heating Value		
Btu/lb	18,900 (avg)	11,500
Btu/gal	115,400 (avg)	73,560
Higher Heating Value		
Btu/lb at 68°F	20,260	12,800
Btu/gal	124,800	84,400
Heat of Vaporization		
Btu/lb	150	396
Btu/gal	900	3,378
Flammability Limits (% by volume in air)	1.4-7.6	4.3-19.0
Specific Heat (Btu/lb - °F)	0.48	0.60

3.3 BASELINE EMISSIONS

3.3.1 Introduction

The baseline emission level represents the level of emissions achieved due to State and local regulations in the absence of additional standards of performance. This parameter is used as an aid in assessing the environmental and economic impacts associated with various emission regulatory alternatives. Most of the States are incorporating regulations to control VOC emissions from bulk terminal gasoline loading operations into their State Implementation Plans (SIPs). A Control Techniques Guideline (CTG)[21] for this source category has been prepared by EPA. This CTG is intended primarily for areas where National Ambient Air Quality Standards (NAAQS) for oxidants are not being attained under present control regulations. The SIPs for States with such non-attainment areas are expected to reflect the recommendations of the CTG by the year 1982. Several of these States will require the CTG level of control throughout the State, and several of the States with no non-attainment areas for oxidants are not expected to require any control measures on gasoline loading operations.

A CTG related to the control of VOC emissions from tank trucks and vapor collection systems[22] (see Sections 3.2.3.3.1 and 3.2.3.3.2) has also been issued by EPA. These two CTG documents are expected to be incorporated together into SIPs.

3.3.2 Control Techniques Guidelines

The bulk terminal CTG recommended emission limit which represents the presumptive norm that can be achieved through the application of reasonably available control technology (RACT) is 80 milligrams of VOCs per liter of gasoline loaded. RACT is defined as the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.

In order to ensure that vapor control processors function effectively, the fugitive emissions from tank trucks and collection system components other than the processor must be controlled. Since tank trucks are the major source of leakage in these systems, the CTG controlling fugitive emissions will be referred to as the "tank truck

CTG." The control approach taken in this CTG is to ensure that good maintenance practices are followed. The recommended regulation prescribes a pressure/vacuum test for gasoline truck tanks and a procedure to test potential leakage points in the vapor collection system. In addition, regulatory agencies may monitor truck tanks and collection systems using a specified combustible gas detection procedure.

3.3.3 Calculation of Baseline Emission Level

3.3.3.1 SIP Regulatory Coverage. The Control Programs Development Division (CPDD) of EPA provided information concerning the extent of regulations expected to be incorporated in SIPs. In addition, proposed SIP revisions for several States were examined to determine compatibility with CTG recommendations. EPA regional offices and State agencies provided updates of information on State regulatory coverage. From these inputs, estimates of regulatory coverage for each State were obtained. From the SIP revision examinations, it is apparent that most States are defining control using two different approaches. The first requires an emission limit of 80 mg/liter, which is consistent with the CTG. The second approach is to require a VOC collection and recovery (or disposal) efficiency of 90 percent. For the purpose of the baseline emissions calculations, these are considered essentially equivalent.

Table 3-4 lists the regulatory coverage expected for each State by the base year 1982. The States listed in the first column require that all terminals within their boundaries achieve a level of control consistent with that of the CTG recommendations (80 mg/liter). The second column includes States which require controls consistent with the CTG only for areas within the State which do not meet the NAAQS for ozone (non-attainment areas). Remaining areas of these States are either covered by submerged fill regulations or are left unregulated. The third column includes States and U.S. Territories which do not have any emission control regulations pertaining to bulk gasoline terminals.

3.3.3.2 Source Emission Factor Categories. As discussed earlier (Section 3.2.3.2), the emission factor for uncontrolled gasoline loading depends in part on the loading method. Emissions from

Table 3-4. STATE REGULATORY COVERAGE FOR BULK GASOLINE TERMINALS[23,24,25,26]

Entire State Consistent With CTG Controls[a]	CTG Controls[a] in Non-Attainment Areas Only	No Control Regulations[d]
California	Alabama[b]	Alaska
Connecticut	Arkansas	Arizona
District of Columbia	Colorado	Hawaii
Georgia	Delaware	Idaho
Illinois	Florida	Kansas
Indiana	Iowa	Mississippi
Louisiana	Kentucky	Montana
Maine	Maryland	Nebraska
Massachusetts	Minnesota	New Mexico
Michigan	Missouri	South Dakota
New Hampshire	Nevada[b]	Wyoming
New Jersey	New York	Guam[e]
Ohio	North Carolina[b]	Puerto Rico[e]
Pennsylvania	North Dakota[c]	Virgin Islands[e]
Rhode Island	Oklahoma[b]	American Samoa[e]
South Carolina	Oregon	
Tennessee	Texas	
Utah	Vermont	
Virginia	Washington	
	West Virginia	
	Wisconsin	

[a]CTG Controls = 80 mg/liter standard or lower, tank truck vapor-tight controls.

[b]Portion of State not covered by CTG controls is covered by submerged fill requirements.

[c]North Dakota has no non-attainment areas for ozone but entire State covered by submerged fill regulations.

[d]Approximately 90 percent of total throughput is loaded by submerged fill.

[e]No non-attainment areas for ozone and gasoline throughput not included in total.

controlled operations (using a vapor control system) are assumed to be equal to the emission limit imposed by the regulation in effect. The total gasoline throughput subject to a particular method of loading or control regulation provides the input necessary to calculate the baseline emission level.

The "normal service" emission factors for uncontrolled splash loading and submerged fill are 1,440 and 600 mg/liter, respectively.[7] These factors are estimated using an American Petroleum Institute calculation method which accounts for such variables as liquid temperature and true vapor pressure, vapor molecular weight, and a saturation factor which depends on tank loading method. The factors can be considered to apply to terminals whose loading is not controlled or is controlled by a requirement for submerged filling. Such terminals are located in the States and U.S. Territories listed in the second and third columns of Table 3-4. The States in the second column of the table, which require submerged filling, are noted with the appropriate designation. Also, some terminals in States with no control regulations use submerged fill or bottom loading. The percentage of total gasoline throughput in submerged fill or bottom loading categories is estimated to be 90 percent in those States where no vapor recovery regulations are in effect.[27,28,29,30] Thus, the remaining 10 percent of the throughput in these States is assigned the emission factor associated with splash loading.

The non-attainment areas of the States in the second column of Table 3-4 are regulated by the level of control recommended in the CTG. All terminals in the States in the first column are similarly regulated. The terminals CTG recommends an adjusted emission limit of 80 mg/liter. The adjusted limit represents the vapor processor emissions in a leak-free vapor collection system. The processor emission factor used, therefore, for terminals covered by CTG-consistent regulations is 80 mg/liter. In addition, a tank truck leakage emission factor of 96 mg/liter has been included for CTG-controlled terminals. This represents 10 percent leakage during loading of trucks which are in balance service at their customer accounts.

The emission factors used for calculation of the baseline emission level are summarized in Table 3-5.

Table 3-5. SOURCE EMISSION FACTORS

Category	Emission Factor
Uncontrolled (Splash fill)	1,440 mg/liter
Submerged Fill	600 mg/liter
CTG-Controlled (Processor)	80 mg/liter
CTG-Controlled (Tank truck)	96 mg/liter

3.3.3.3 Baseline Emission Level Calculations. Since the VOC emission factors for gasoline loading at bulk terminals are expressed in terms of the volume of gasoline loaded, it is necessary to distribute the gasoline throughput into emission factor categories. During the year 1978, 443 billion liters (117 billion gallons) of gasoline was consumed in the U.S. It is assumed that all gasoline consumed within a State was loaded at a terminal in that State. Any errors due to interstate transport of gasoline in tank trucks were assumed to balance out.

The throughputs for States whose regulatory coverage applies statewide (either controlled or uncontrolled) are readily assigned to the appropriate emission factor category. For those States where the regulations differ in separate geographical areas, fractions of the total State gasoline consumption can be assigned to the proper regulatory categories by assuming that the gasoline consumption in these areas is proportional to the population. Although the ideal situation would have been to know the location of all 1,511 terminals in the country, this information is not readily available. Thus, the estimate of location based on population was used to assign gasoline throughput fractions to emission factor categories. This method is commonly used for emissions estimation when exact point source locations are unknown. Since the regulatory geographical areas almost exclusively follow county boundaries, population estimates for each area[31] are obtainable for the purpose of calculating the percentage of throughput associated with each emission factor. The gasoline consumption in the area in question is determined by the following relationship:

$$\text{Gasoline Consumption in Area X} = \frac{\text{Population of Area X}}{\text{State Population}} \times \text{State Gasoline Consumption}$$

This method was used to categorize the gasoline throughputs for all of the States. These calculations indicate that approximately 71 percent of the nationwide gasoline loading at existing terminals will be controlled to the level recommended by the CTG.

Based upon government estimates, gasoline consumption will experience little net change from 1978 to 1985.[32] This is due to economic factors and increasing automobile fuel efficiency. The 1978 gasoline throughput was, therefore, assumed to be equivalent to that in the base year of 1982. Section 8.1.2.1 of Chapter 8 discusses gasoline supply and demand further.

Emissions for the base year were calculated using the selected emission factors and the gasoline throughputs for each category. Table 3-6 presents the results of these calculations, which indicate that, although the uncontrolled and submerged fill categories represent only about 28 percent of the nationwide gasoline throughput, they account for almost 60 percent of the total emissions.

Table 3-6. BASELINE EMISSIONS
(Base Year 1982)

Category	Gasoline Throughput (10^6 liters)	Percent of Total Throughput	Emission Factor (mg/liter)	VOC Emissions (Mg/year)	Percent of Total Emissions
Uncontrolled (Splash Fill)	9,997	2.3	1,440	14,396	10.3
Submerged Fill	113,734	25.7	600	68,240	49.2
CTG Control:					
Processors			80	25,527	18.4
	319,087	72.0			
Tank Trucks			96	30,632	22.1
Total	442,818	100.0		138,795	100.0

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4.0 EMISSION CONTROL TECHNIQUES

4.1 INTRODUCTION

It is estimated that about 400 vapor control systems are in commercial operation at bulk gasoline terminals in the U.S. The primary impetus for the installation of these systems has been the regulations contained in State Implementation Plans (SIP).

The control of VOC emissions at a bulk terminal begins with the method of gasoline loading used at the loading racks. For example, in the absence of a vapor control system, a tank truck filled by top splash loading will emit a greater quantity of VOC than will a tank truck filled by the top submerged or bottom loading method. Also, in a system using vapor control, the vapor-tight condition of the tank trucks is a major factor in determining the overall total VOC emissions from the loading activity. Finally, the various components of the collection system, such as flexible hose, relief valves, and the vapor holder (when used), are potential sources of leakage and must be inspected and maintained in order to ensure that they are vapor-tight.

4.2 PROCESS MODIFICATIONS

Gasoline loading activity at a bulk terminal is generally a process which is fixed by the type of equipment installed at the terminal. Thus, for a given loading rack equipment configuration, there is little opportunity for process changes which would reduce VOC emissions. There is no evidence that lowering the gasoline pumping rate, for example, would result in lower emissions through decreased surface turbulence inside the tank truck. A well-maintained and properly operating vapor processor is designed to collect sufficient VOC vapors so that in conjunction with a leak-free system the prescribed emission limit is achieved. A properly designed and sized vapor collection system, including piping and valves, will not subject the tank truck to excessive back pressure. The system should be designed so that the back pressure does not exceed 34 millimeters of mercury (18 in. of water) gage pressure (see Section 4.3.1).

The most effective modifications leading to emission reduction involve changes in equipment, including the elimination of vapor leaks in tank trucks, conversion from top splash to submerged fill or bottom loading of gasoline, and installation of a vapor control system.

4.3 CONTROL OF FUGITIVE EMISSIONS

4.3.1 Tank Truck Leakage

The effectiveness of vapor control systems at bulk terminals is dependent upon the absence of leaks in the vapor-containing equipment. Gasoline delivery tank trucks have been demonstrated to be major sources of vapor leakage during loading operations, accounting for VOC control system losses as high as 100 percent for some individual tank truck loadings.[1] In the EPA-sponsored terminal tests, the average vapor loss due to tank truck leakage was 30 percent. These tests were performed in areas having no tank truck vapor tightness regulations. The existence of regulations requiring tank truck vapor tightness can result in a lower average vapor leakage. The average leakage in an area of California requiring vapor tightness certification testing was found to be 10 percent.[2]

An average 10 percent tank truck leakage rate was found in an EPA test program[3] where tank truck vapor leakage was monitored prior to any maintenance necessary to pass the annual certification test. During the 2-week test period 27 tanks were quantitatively tested for vapor leakage using a pressure/vacuum test. The time since the last certification varied from 20 days to 365 days. Leakage rates varied from less than 2 percent to about 35 percent. A more thorough discussion of these data can be found in Appendix C, Section C.1.4. Sources of vapor leakage on tank trucks include dome covers, pressure-vacuum vents, and vapor collection piping and vents. Smaller instances of leakage occur at tank welds, liquid and vapor transfer hoses, overfill sensors, and vapor couplers.

In order to achieve significant VOC emission reduction at bulk terminals, tank truck vapor leakage must be controlled. The Control Techniques Guideline (CTG) for gasoline tank trucks[4] recommends a vapor tightness regulation and test procedure which reduces VOC losses from tank trucks due to vapor leaks. Under this recommended regulation, the tanks and their vapor collection equipment are not to sustain a pressure change of more than 5.6 mm of mercury (3 in. of H_2O) in 5 minutes when pressurized to 34 mm of mercury (18 in. of H_2O) or evacuated to 11 mm of mercury (6 in. of H_2O). These pressure limits reflect the way in which the pressure-vacuum vent valves operate on tank trucks. The valves are spring loaded and designed to open slowly and be fully open at 1 psi (27 in. of H_2O) pressure and 0.4 psi (10 in. of H_2O) vacuum. The limits of 34 mm of mercury and 11 mm of mercury recommended in the CTG represent the maximum pressures which can be applied to the tank before the vents begin to open.[5] The pressure change limit of 5.6 mm of mercury represents an approximate 99 percent tank vapor containment efficiency.[6] The vapor tightness of tank trucks can deteriorate quickly during normal use. Test data have shown that some trucks may not be able to meet the vapor-tight criteria as soon as two weeks after vapor-tight certification.[7] The monitoring provisions of the regulations recommended by the CTG permit monitoring as needed using a portable combustible gas detector.

Through installation of the proper equipment, and through periodic inspection and subsequent repair or replacement of defective components, leakage from tank trucks can be minimized to the extent that the certification criteria specified by the CTG can be satisfied. Earlier EPA reports summarize the appropriate maintenance procedures,[2] as well as tank truck retrofit considerations.[8] Costs involved in placing a truck in vapor-tight condition and maintaining the condition are discussed in Section 8.2 of Chapter 8.

4.3.2 <u>Vapor Collection System Leakage</u>

Leakage from collection system components between the tank truck and the vapor processing system was discussed in Section 3.2.3.2.2. Such leaks in the collection system are minimized when inspection of all such vapor handling equipment is included in the routine maintenance program at a terminal, and faulty components are replaced or repaired. Designing a system in order to maintain the lowest practicable working pressures will also aid in maintaining leakage rates at minimum levels. One practical means of locating leakage points is through a visual examination of collection system components. This method would not be a quantitative measure of vapor leakage, but would identify the major sources of leakage through sound, smell, or visual appearance of fumes near a leak. A visual examination would not require any instrumentation. Another means of leak checking involves the use of a combustible gas detector, which can locate smaller, less noticeable leaks.

4.4 TYPICAL COLLECTION SYSTEM

As discussed in Section 3.2, a vapor collection system consists of all the piping and components necessary to safely transfer the air-vapor mixture from tank trucks to a vapor processor. The three most common pieces of equipment utilized between the loading racks and the processor are the liquid knockout tank, the saturator tank, and the vapor holder.

The liquid knockout tank removes liquid gasoline from the vapor return line and stores it for subsequent recovery or disposal. Liquid can enter the vapor line due to accidental overfilling or can form in the line under certain ambient conditions. Of the 22 systems tested by EPA, 7 of them utilized a liquid trap or knockout tank.

Saturator tanks contain gasoline sprays to raise the VOC vapor concentration above the explosive range. Saturation spraying is also used in conjunction with vapor holders and as a first stage in some vapor processing systems. Ten of the systems tested by EPA utilized saturation, or enrichment of the vapor stream.

Vapor holders store air-vapor mixture generated at the loading racks until some preset capacity is reached, and then release it to the control system for processing. Thus, fluctuations in VOC concentration and volume are minimized, and the vapors are processed on a batch basis rather than running the processor continuously. Generally, a vapor holder consists of a large tank containing a flexible bladder used as a level sensor. Eleven of the systems tested by EPA utilized a vapor holder.

4.5 VAPOR PROCESSING SYSTEMS

EPA-sponsored testing was performed at 22 gasoline terminals using 6 different vapor processing approaches. The results of the tests are summarized in Table 4-1. Daily average results are presented for the three-day tests to allow inspection of the variation of individual control systems. Additional information on the tests, including referenced test reports, can be found in Appendix C. The vapor processing techniques tested during the EPA program are discussed in the following section.

4.5.1 Description of Control Technologies

4.5.1.1 Carbon Adsorption (CA). The carbon adsorption (CA) vapor recovery system uses beds of activated carbon to remove VOC from the air-vapor mixture. These units generally consist of two vertically positioned carbon beds and a carbon regeneration system. During gasoline tank truck loading activity, one carbon bed is in the adsorbing mode while the other bed is being regenerated. Approximately 70 carbon adsorption units are currently in operation at terminals.[9]

Air-vapor mixture from the loading racks enters the base of one of the adsorption columns and the VOC components are adsorbed onto the activated carbon as the gases ascend. Adsorption in one carbon bed occurs for a specific timed cycle before switch-over to desorption occurs. The nearly saturated carbon bed is then subjected to vacuum, steam, or thermal regeneration, or a combination of these methods, and the VOC are stripped from the bed. Vacuum regenerated units recover VOC by absorption in a gasoline stream which circulates between the control unit and gasoline storage. The air and any remaining VOC exiting from the absorber are passed again through the adsorbing bed, and exhausted to the atmosphere. Steam-regenerated units condense the VOC-water mixture and return the separated product to storage. Some vacuum regenerated systems remain in operation for up to two hours after loading activity ceases, in order to collect any residual vapors in the system and to assure complete regeneration of the carbon beds. Figure 4-1 shows a simplified schematic diagram of an activated carbon vapor processor.

Table 4-1. VOC EMISSION TEST DATA SUMMARY

Test Number	Test Date	Control Unit[a]	Terminal Throughput (liters/day)	Inlet VOC Concentration (Percent)[b]	Outlet VOC Concentration (Percent)[b]	Processor VOC Emissions (mg/liter)	Total System Emissions (mg/liter)	Adjusted[c] Processor Emissions (mg/liter)	Control Efficiency (Percent)
1	5/25/77	CA	284,000	56.2	6.0	64.2	374	92.6	90.9
	5/26/77			60.4	2.2	5.4	378	8.5	99.2
	5/27/77			48.8	0.14	2.7	285	3.9	99.6
2	3/1/78	CA[d]	190,000	20.5	0.18	1.2	133	1.8	99.5
	3/2/78			13.5	0.30	2.1	74.4	2.8	99.0
	3/3/78			15.4	0.33	2.5	129	3.9	98.9
3	10/24/78	CA	303,000	45.0	0.83	10.8	26.6	11.0	98.6
	10/25/78			40.1	0.83	9.6	17.7	9.7	98.8
	10/26/78			43.8	3.7	63.4	63.4	63.4	92.6
4	11/73[e]	TO[d]	1,100,000	29.2[f]	0.002[f]	1.0	176	1.4	99.8
5	1/25/78	TO	757,000	36.9	0.06	77.6	297	107	86.6
	1/26/78			39.6	0.03	36.7	205	47.3	93.7
	1/27/78			23.1	0.02	32.8	103	39.0	91.1
	1/30/78			24.1	0.02	24.2	97.3	28.6	94.0
6	1/10/78	TO	950,000	33.9	0.004	21.4	78.9	24.7	93.6
	1/11/78			27.8	0.005	22.4	91.7	27.0	93.2
	1/12/78			31.1	0.008	39.8	154.9	50.9	90.3
7	2/23/78	TO[d]	1,514,000	18.6	1.7	23.7	93.3	29.4	90.0
	2/24/78			27.3	0.7	7.5	110	9.3	98.2
	2/27/78			28.3	0.8	10.3	133	13.2	97.7
8	12/17/74	REF	380,000	17.0	3.4	33.3	134	44.0	89.4
	12/19/74			18.8	3.6	39.4	174	54.4	88.9

Table 4-1. VOC EMISSION TEST DATA SUMMARY (Continued)

Test Number	Test Date	Control Unit[a]	Terminal Throughput (liters/day)	Inlet VOC Concentration (Percent)[b]	Outlet VOC Concentration (Percent)[b]	Processor VOC Emissions (mg/liter)	Total System Emissions (mg/liter)	Adjusted[c] Processor Emissions (mg/liter)	Control Efficiency (Percent)
9	9/20/76	REF	1,430,000	35.6	4.8	51.6	254	72.2	89.8
	9/21/76			50.6	4.7	52.3	107	58.1	89.4
	9/22/74			50.9	3.6	29.9	52.1	31.1	94.6
10	11/10/76	REF	810,000	23.7	3.6	49.1	173	61.9	86.7
	11/11/76			17.8	3.3	57.1	67.3	58.8	83.2
	11/12/76			13.3	3.3	54.2	87.4	61.8	77.1
11	8/22/78	REF	g	NA[h]	56.8	1318	1318	1318	44.3
	8/23/78			88.2	29.8	841	841	841	63.3
	8/24/78			75.2	38.4	794	794	794	62.2
12	9/26/78	REF	1,514,000	31.7	5.3	67.2	142	75.9	88.3
	9/27/78			30.0	6.2	103	103	103	86.1
	9/28/78			39.8	4.9	61.9	134	68.1	90.6
13	10/10/78	REF	1,514,000	47.9	3.2	j	j	j	j
	10/11/78			52.4	3.1	j	j	j	j
	10/12/78			51.8	3.5	j	j	j	j
14	12/11/74	CRA[d]	600,000	18.2	4.7	31.0	141	73.5	61.4
	12/12/74			21.5	4.3	31.6	141	57.2	76.7
15	9/23/77	CRA[d]	1,190,000	48.8	3.9	30.7	314	44.5	95.1
	9/24/77			38.9	3.4	30.5	214	47.0	91.0
	9/25/77			NA[h]	3.2	NA[h]	NA[h]	NA[h]	NA[h]
16	2/20/78	CRA[d]	g	29.3	5.3	NA[h]	NA[h]	NA[h]	NA[h]
	2/21/78			31.2	6.1	61.2	225	88.1	83.5
	3/8/78			28.7	5.3	59.5	NA[h]	NA[h]	NA[h]
	3/9/78			27.1	5.3	57.2	NA[h]	NA[h]	NA[h]

Table 4-1. VOC EMISSION TEST DATA SUMMARY (Concluded)

Test Number	Test Date	Control Unit[a]	Terminal Throughput (liters/day)	Inlet VOC Concentration (Percent)[b]	Outlet VOC Concentration (Percent)[b]	Processor VOC Emissions (mg/liter)	Total System Emissions (mg/liter)	Adjusted[c] Processor Emissions (mg/liter)	Control Efficiency (Percent)
	5/2/78			17.0	2.5	40.9	255	78.5	82.4
17	5/3/78	CRA[d]	1,000,000	30.6	2.5	45.1	179	58.2	90.2
	5/4/78			23.2	2.5	35.9	138	52.1	84.2
	8/2/78			35.5	3.6	32.2	180	41.5	93.7
18	8/3/78	CRA[d]	1,514,000	37.6	3.8	43.1	371	65.1	93.3
	8/4/78			45.0	4.1	43.0	232	52.9	94.8
19	9/21/78	CRA[d]	g	56.6	3.6	85.9	149	91.0	91.8
20	3/6/78	CRC[d]	5,678,000[i]	22.1	3.4	41.0	108	48.4	89.0
	3/7/78			38.4	3.8	44.4	180	55.9	91.5
	8/16/78			64.8	11.9	j	j	j	j
21	8/17/78	CRC[d]	g	75.6	12.9	j	j	j	j
	8/18/78			59.7	13.6	j	j	j	j
	4/11/78			29.3	9.2	97.0	225	130	74.1
22	4/12/78	LOA	1,514,000	29.0	5.3	52.9	195	73.0	85.9
	4/13/78			28.3	9.2	86.7	225	119	76.7

NOTES — Table 4-1

[a] CA - Carbon Adsorption
TO - Thermal Oxidation
REF - Refrigeration
CRA - Compression-Refrigeration-Absorption
CRC - Compression-Refrigeration-Condensation
LOA - Lean Oil Absorption

[b] Volume percent as propane, except as noted.

[c] Total VOC emissions from processor (control unit) adjusted to account for tank truck leakage.

[d] Vapor holder used.

[e] Testing performed for nearly six months; no daily averages reported (see Section C.2 of Appendix C).

[f] Volume percent as methane.

[g] Requested to be kept confidential.

[h] Parameter not calculated due to lack of necessary test data.

[i] Four terminals combined in complex.

[j] Not calculated due to unknown quantity of leakage from vapor collection system.

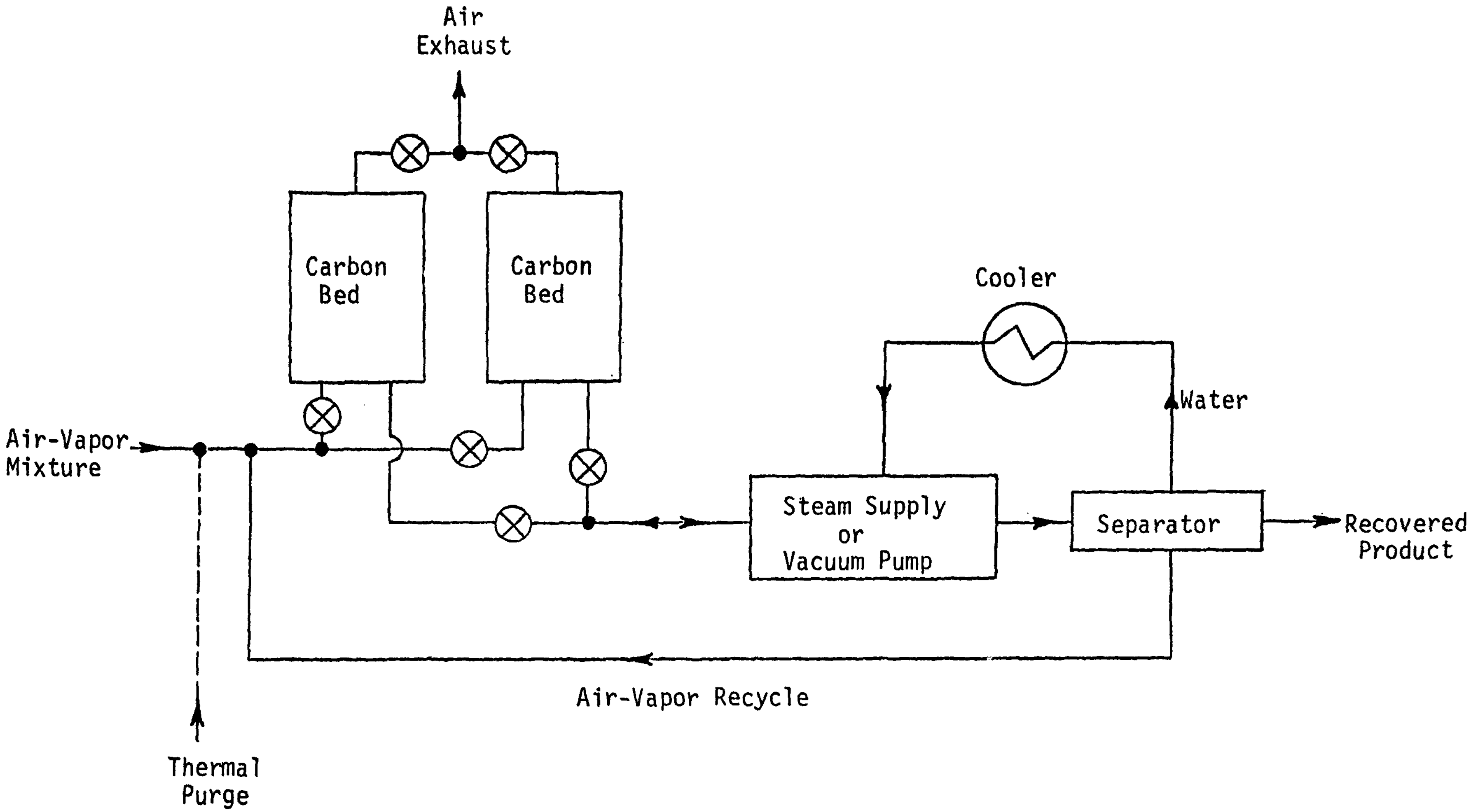

Figure 4-1. Schematic Diagram of a Carbon Adsorption System (CA)

Vapor processor outlet daily average mass emissions, adjusted for collection system leakage, ranged from 1.8 mg/liter to 92.6 mg/liter, for an average mass emission level in the three tests of 22.0 mg/liter. Two days of system operation have been omitted in the evaluation of the performance of the carbon adsorption system. On the first day of Test No. 1, the bed switching timer was incorrectly set, leading to breakthrough on one bed. On the third day of Test No. 3, two tank trucks were purposely loaded simultaneously, a departure from the terminal's standard practice and over the design capacity for this particular unit, in order to determine the effect of this on mass emissions. Both of these instances are deviations from the normal operation of the system, and so the measured emissions on these days are not considered representative of the system's performance. Daily average adjusted mass emissions on the remaining seven days of testing ranged from 1.8 to 11.0 mg/liter, for an average of 5.9 mg/liter. These tests were performed on the vacuum-regenerated type of CA unit, which is the only type currently in commercial operation at bulk gasoline terminals. Section C.1.2 of Appendix C discusses the tests further.

4.5.1.2 Thermal Oxidation (TO). The thermal oxidation (TO) control unit relies on burning VOC vapors (using a pilot flame) to produce non-polluting combustion products. In this system no gasoline is recovered. Approximately 40 thermal oxidizer units are currently being used at terminals.[10,11,12]

Vapors from the loading racks are piped either to a vapor holder or directly to the oxidizer unit. When a vapor holder is used, operation of the oxidizer begins when the holder reaches a preset level, and ends when the holder is empty. With no vapor holder in the system, the oxidizer is energized by means of pressure in a vapor line, indicating that tank truck loading is in progress, or by an electrical signal produced by a manual activation at the loading rack. In some cases propane is injected into the vapor stream to keep the VOC level above the explosive range.

When gasoline dispensing equipment at the racks is activated, the combustion air fan starts and purges the combustion chamber of any remaining combustible vapors. After the purge period the pilot fuel (usually propane) is admitted and a spark igniter lights the pilot flame. Approximately one minute after fan activation the vapors are admitted to the oxidizer chamber. On some units the pilot flame is activated only long enough to ignite the combustible vapors, while on others the pilot flame burns continuously during the vapor combustion process. Combustion air is admitted to the unit by means of an adjustable damper which is controlled by temperature. As the temperature in the combustion chamber rises, the damper is opened to admit more air. Normal operating temperature in the chamber is approximately 760°C (1400°F).

Other equipment included in TO systems are flame arrestors to prevent flashback from the unit to the loading area, and in some later models an isolating valve to prevent vapor flow under low pressure conditions. Figure 4-2 shows a simplified schematic diagram.

Thermal oxidizer units have the advantages of low capital cost, simplicity of design, and high processing efficiency. A disadvantage is that they do not recover gasoline vapors as liquid product. Processor outlet daily average mass emissions in four tests, adjusted for system leakage, ranged from 1.4 mg/liter to 107 mg/liter, for an average of 34.3 mg/liter. Daily average adjusted mass emissions measured in systems with no vapor holder ranged from 24.7 to 107 mg/liter, for an average of 46.4 mg/l. Adjusted emissions from systems incorporating a vapor holder ranged from 1.4 to 29.4 mg/liter, averaging 13.3 mg/liter. Section C.1.2 of Appendix C discusses the thermal oxidation tests further.

Some recently developed control systems consist of a compression-aftercooler stage to recover most of the displaced vapors as liquid gasoline, followed by a thermal oxidation stage to reduce VOC emissions to within the required level. Test data are not available to permit an evaluation of this control technology; however, a small number of these systems are operating at bulk terminals. They provide one option for recovering some product while achieving the high control efficiency of the thermal oxidation approach.

4.5.1.3 Refrigeration (REF). Refrigeration type recovery units (REF) remove VOC from an air-vapor mixture by straight refrigeration

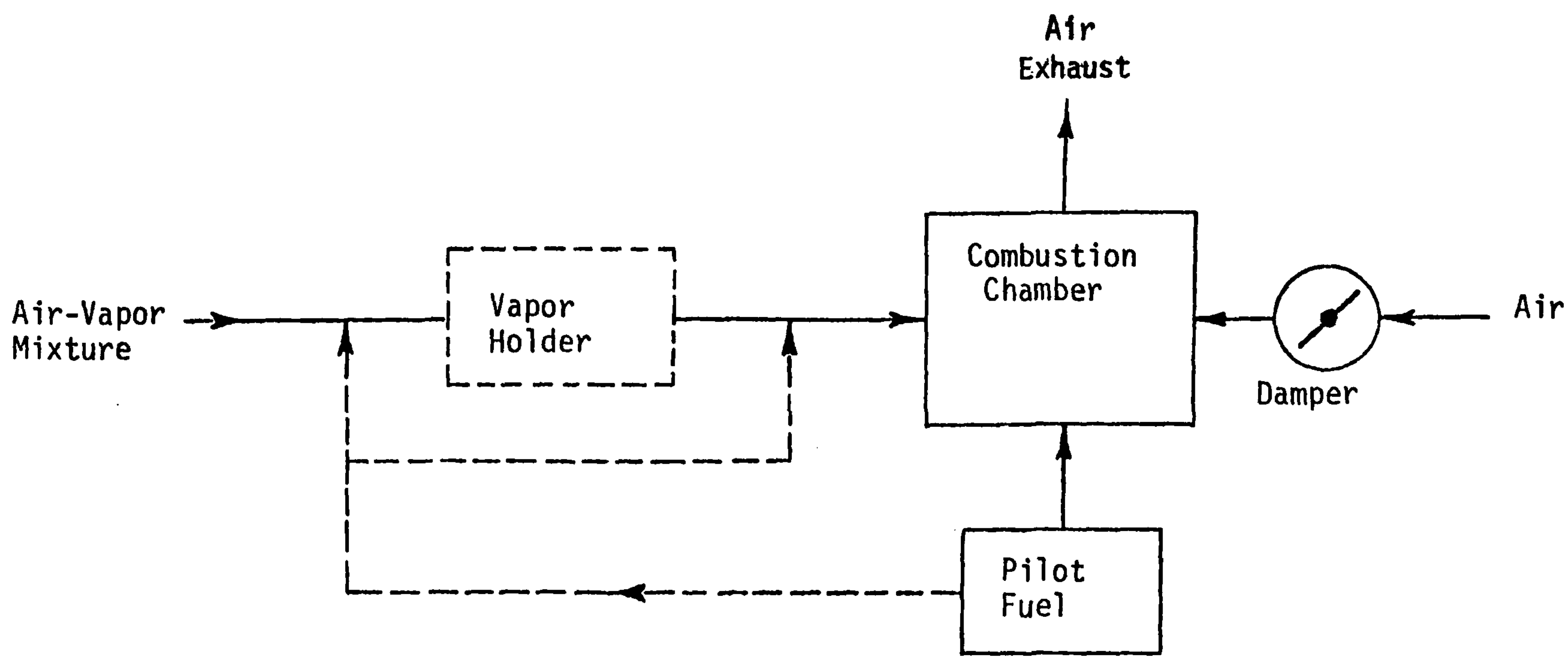

Figure 4-2. Schematic Diagram of a Thermal Oxidizer System (TO)

(Dotted Lines Indicate Optional Equipment) at atmospheric pressure. It is estimated that there are 130 units of this type in commercial operation at gasoline terminals.[13,14]

In older units, vapors displaced from tank trucks enter a condenser section where methylene chloride "brine" is pumped through the finned-tube sections of a heat exchanger. Brine temperature in this section ranges from -62°C to -82°C (-80°F to -115°F). Some units contain a precooler section (glycol and water solution circulating at 1.1°C (34°F)) to remove most of the water from the gases prior to the main condenser. There are no compression stages in this type of unit. The condensed product is collected and pumped to one of the product storage tanks. The cold collection surfaces are periodically defrosted by pumping warm (32°C or 90°F) trichlorethylene through the condenser. This defrost fluid is kept warm by heat salvaged from the refrigeration equipment. Recovered water passes to a waste storage tank or gasoline-water separator. The defrost cycle takes from 15 to 60 minutes, depending on the amount of ice accumulated on the finned tubes.

On many refrigeration units the defrost cycle is performed during periods of no loading activity since the unit cannot collect VOC during the defrost cycle. Some units, however, contain a double set of heat recovery and low temperature coils over which the vapor is alternately passed. This is accomplished using a switch-over damper to divert the flow to one or the other set of coils. Thus one set is collecting VOC while the other set is defrosting. This means that the unit can operate continuously with no downtime for defrosting. Newer refrigeration units use direct expansion to refrigerate the condenser coil collection surfaces, thus eliminating the chilled brine. Figure 4-3 shows a simplified schematic diagram of the refrigeration control unit tested by EPA.

Acceptable recovery efficiencies for the refrigeration system are dependent on the unit maintaining the necessary -68°C to -84°C (-90°F to -120°F) brine temperature in the condenser recovery section. This in turn depends on assuring that the fluid levels remain at proper operating capacities by maintaining the system in a leak-free condition. In addition, defrost cycles must be coordinated with tank truck loading activities so that the condenser elements are always at or near the

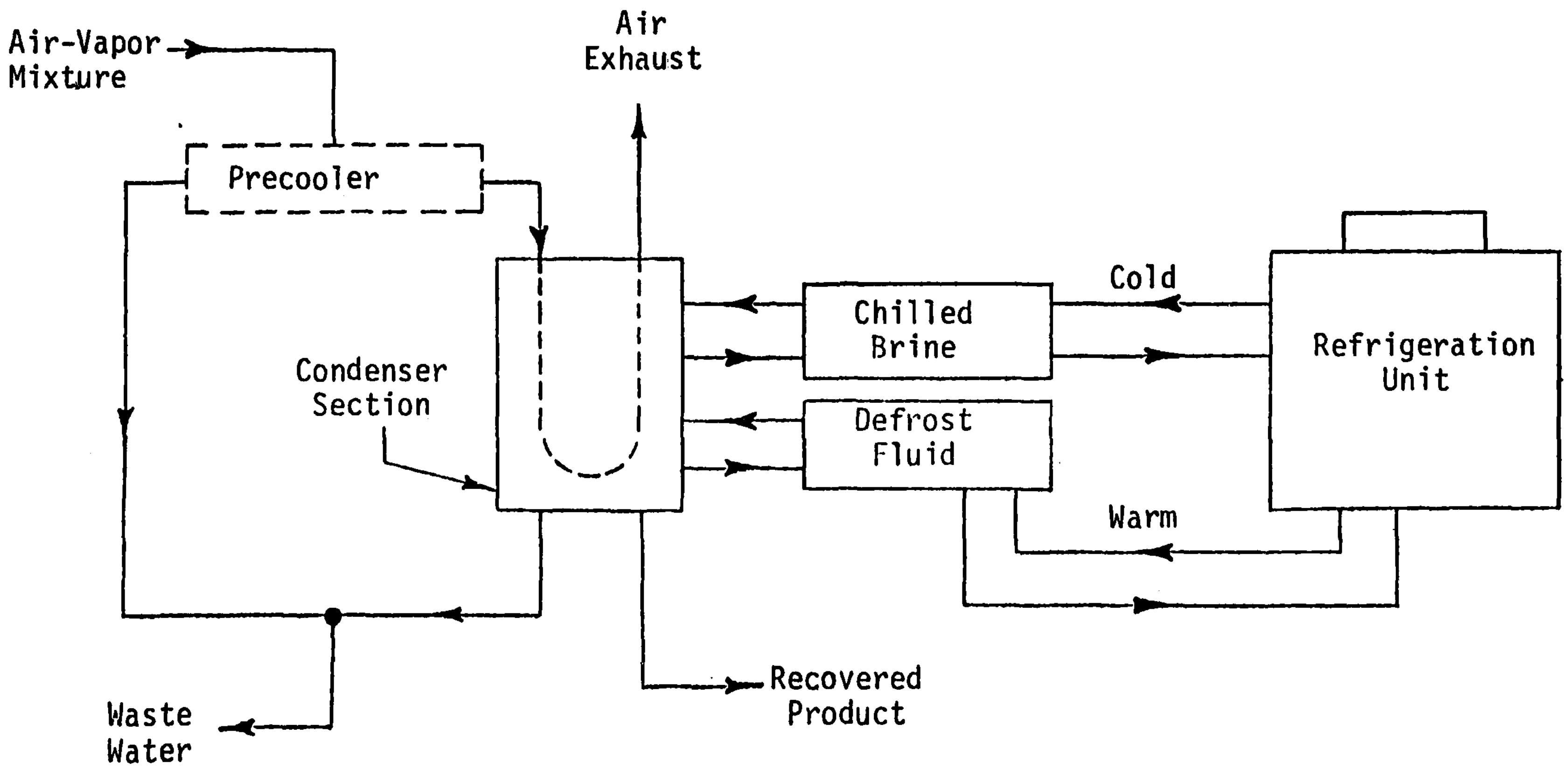

Figure 4-3. Schematic Diagram of a Refrigeration System (REF)

design temperature during vapor collection. The units employing a switch-over damper, when operating properly, are not subject to concern over defrost scheduling.

In one of the six EPA-sponsored tests involving refrigeration type vapor recovery units (Test No. 11), the measured emissions were unusually high compared to those from other REF tests, as a result of problems with the test equipment and the recovery unit itself. In another REF test (Test No. 13), serious leakage of air-vapor mixture from the vapor collection system caused almost half of the mixture to escape to the atmosphere before reaching the recovery unit. Data from these two tests were not included in the REF system performance evaluation. Daily average VOC emissions in the four remaining tests (Test Nos. 8, 9, 10, and 12), adjusted for tank truck leakage, ranged from 31.1 to 103 mg/liter. The control efficiency of the processor in these four tests ranged from 77.1 to 94.6 percent. During two tests (Test Nos. 8 and 9), the refrigeration equipment was not maintaining the low temperatures required for efficient vapor collection because of system refrigerant loss. In one test on a refrigeration type vapor processor performed by a local regulatory agency in California, adjusted mass emissions were 14 mg/liter. Three additional California tests on direct expansion type systems measured outlet mass emissions of 5 mg/liter, 36 mg/liter, and 48 mg/liter. Sections C.1.2 and C.1.3 of Appendix C discuss these tests further.

These test results reflect the ability of properly maintained and operated refrigeration type vapor processors to achieve 80 mg/liter, and the data indicate that the newer models can achieve emission rates considerably lower than 80 mg/liter.

4.5.1.4 Compression-Refrigeration-Absorption (CRA). In a compression-refrigeration-absorption (CRA) vapor recovery unit, the vapors from the loading racks are first passed through a saturator which sprays liquid gasoline into the air-vapor gas stream. This ensures that the VOC concentration is above the explosive range. The saturated gas mixture is stored in a vapor holder, until at a preset level it is released to the control unit. The vapor holder is usually a special tank containing a bladder with variable volume and constant pressure. A gasoline storage tank with a lifter roof can also function in this capacity. Approximately 100 CRA units are currently being used in gasoline terminals.[15]

The first stage of processing is a compression-refrigeration cycle in which water and heavy VOC are compressed, cooled, and condensed. The uncondensed vapors move into a packed absorber column where they are contacted by chilled gasoline (4°C or 39°F) drawn from product storage, and absorbed. The fresh gasoline stream is used first in the saturator, then it passes through an economizing heat exchanger as it enters the absorber. The rich absorbent also passes through the heat exchanger before being pumped back to storage. The operation of the control system is intermittent, starting when the vapor holder is filled and stopping when it has emptied. Cleaned gases are vented from the absorber column to atmosphere. A simplified schematic diagram of a typical CRA control unit is shown in Figure 4-4.

The results of EPA-sponsored tests on CRA units at bulk terminals indicate that these units are capable of achieving a VOC emission level below 80 mg/liter. Daily average mass emissions, adjusted for system leakage, in six tests ranged from 41.5 mg/liter to 91.0 mg/liter, for an average of 62.5 mg/liter. No test data were omitted in the evaluation of this control technique because there were no serious testing irregularities or equipment malfunctions reported during the tests. Section C.1.2 of Appendix C discusses these tests further.

4.5.1.5 Compression-Refrigeration-Condensation (CRC). A vapor recovery system employing a compression-refrigeration-condensation (CRC) unit makes use of a vapor holder to store accumulated air-vapor mixture, and a saturator for ensuring that the VOC concentration is above the explosive range. The unit is activated and begins processing vapors when the vapor holder has filled to a preset level.

Incoming saturated air-vapor mixture is first compressed in a two-stage compressor with an intercooler. Condensate is withdrawn from the intercooler prior to compression in the second stage. The compressed vapors then pass through a refrigeration-condenser section where they are returned along with the intercooler condensate to a gasoline storage tank. Cleaned gases are exhausted from the top of the condenser. Figure 4-5 shows a simplified schematic diagram of a

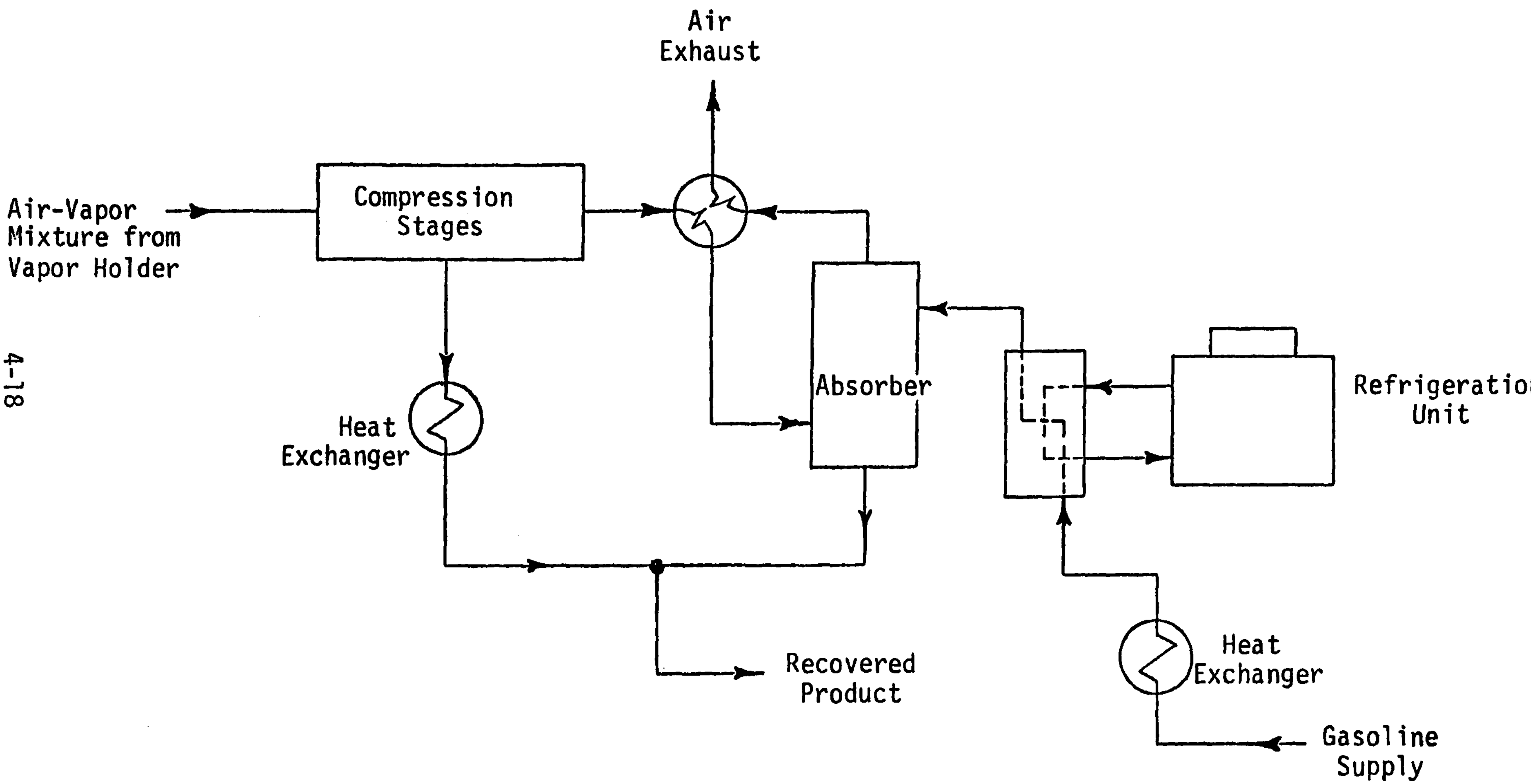

Figure 4-4. Schematic Diagram of a Compression-Refrigeration-Absorption System (CRA)

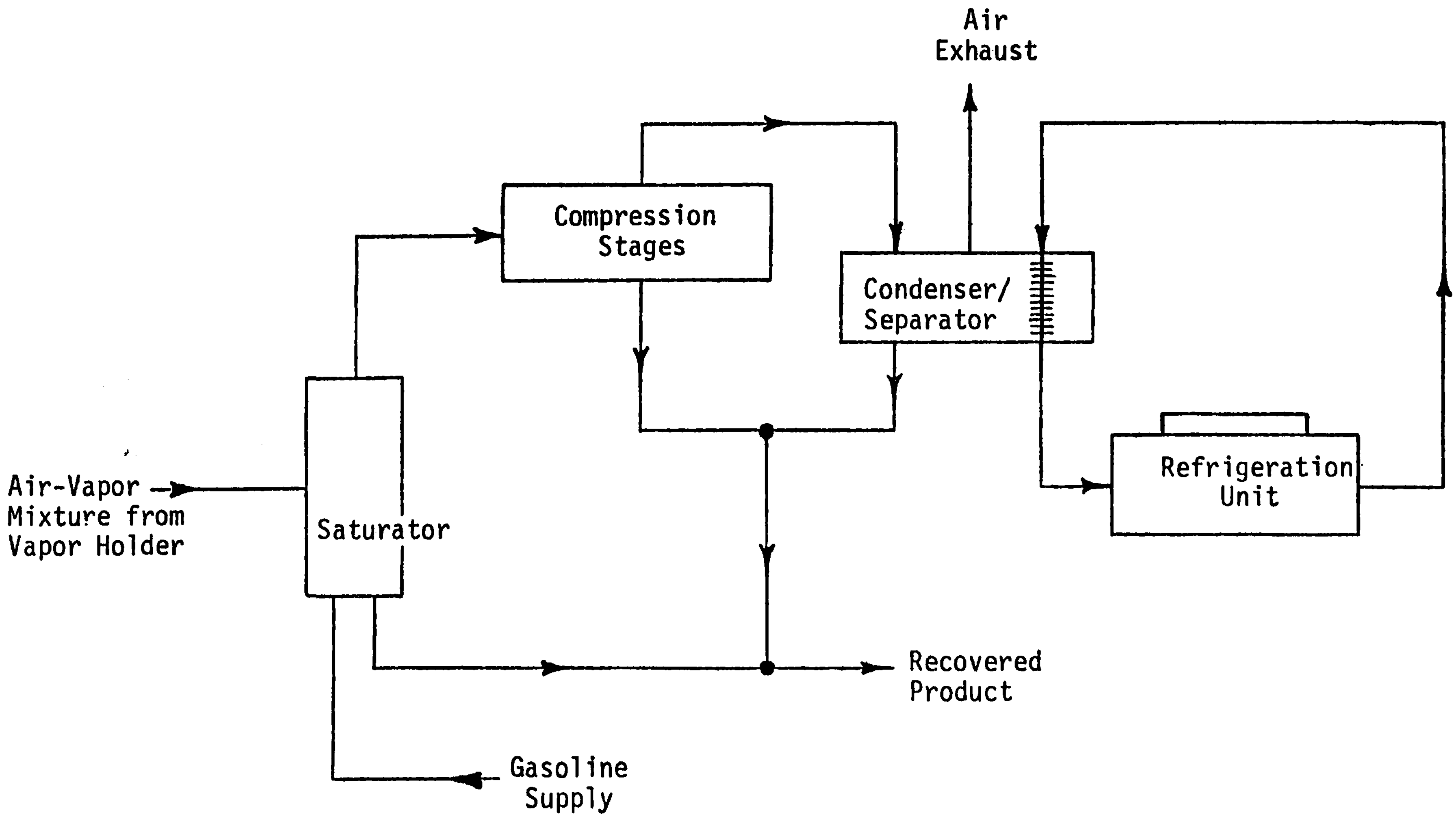

Figure 4-5. Schematic Diagram of a Compression-Refrigeration-Condensation System (CRC)

CRC control unit. Based upon 114 letter responses, it was estimated that there were approximately 40 CRC units currently used to control VOC emissions at terminals.

Two EPA-sponsored tests were performed at terminals employing CRC units. At one terminal, air-vapor leakage from the vapor holder could not be determined; therefore, the adjusted emissions could not be calculated (Test No. 21). The daily average adjusted VOC emissions for Test No. 20 were 48.4 and 55.9 mg/liter, for an average of 52.2 mg/liter. Section C.1.2 of Appendix C discusses these tests further.

4.5.1.6 Lean Oil Absorption (LOA). The lean oil absorption unit (LOA) relies on the absorption of the vapors released by tank truck loading ("light ends") in lean oil, which may be No. 2 diesel oil or gasoline from which the light ends have been previously removed. In this unit, vapors enter the base of an absorber column and create a pressure differential (ΔP) across an orifice mounted at the inlet. The ΔP creates a signal proportional to the vapor flow rate, which starts a lean oil pump and controls the amount of lean oil pumped from storage to the column. Cooled lean oil absorbs VOC vapors in the packed absorber column. In one type of unit the enriched gasoline (used lean oil) is returned directly to a gasoline storage tank. Another LOA unit uses heat and pressure to regenerate and re-use the lean oil, returning the removed gasoline vapors to storage. Cleaned air-vapor mixture is exhausted from the LOA control unit to atmosphere.

Lean oil for one type of unit is produced independently by heating gasoline in order to evaporate off the light ends. This lean oil is then cooled and stored in an insulated tank. Figure 4-6 shows a simplified schematic diagram of this type of LOA control unit.

Adjusted daily average mass emissions in the single efficiency test performed by EPA on a lean oil absorption control unit range from 73.0 mg/liter to 130 mg/liter, for an average of 107 mg/liter. Section C.1.2 of Appendix C discusses this test further.

The lean oil absorption type unit is not in widespread use at bulk terminals, and oil companies have indicated a tendency toward replacing these units with other types of control systems. Generally,

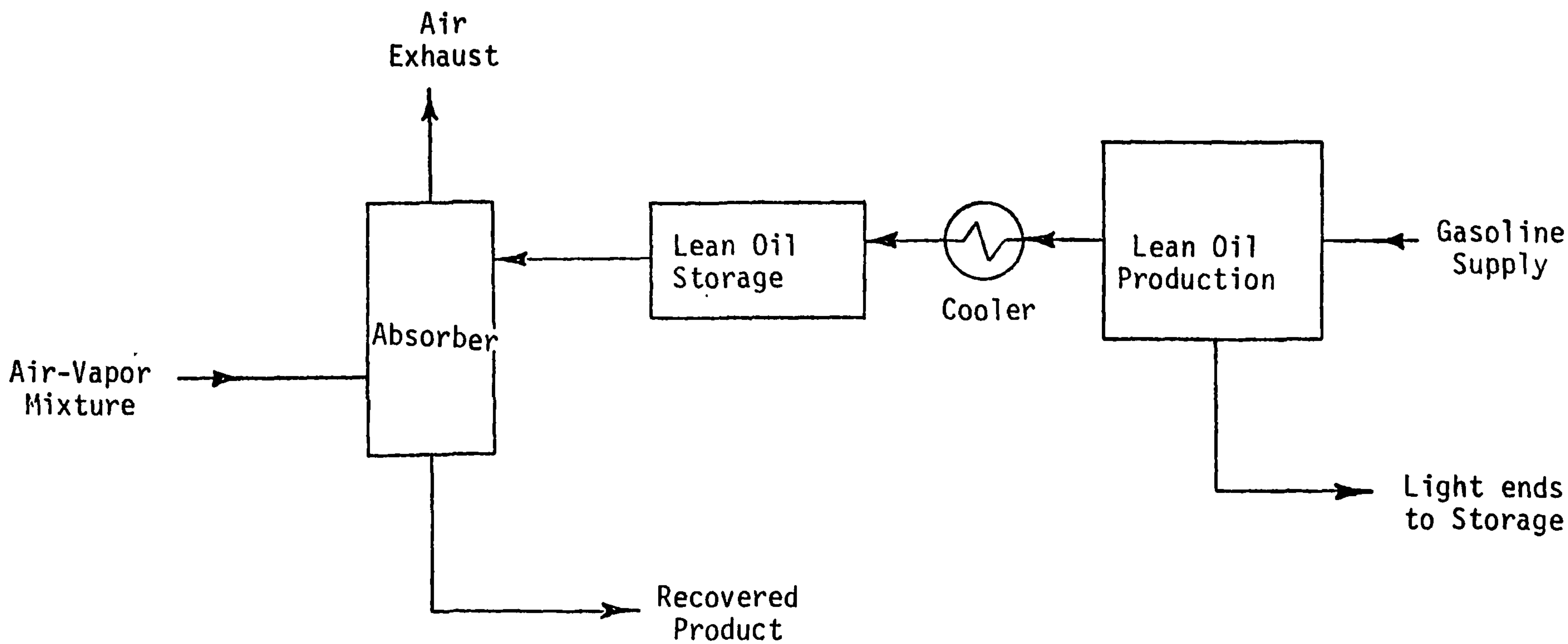

Figure 4-6. Schematic Diagram of a Lean Oil Absorption System (LOA)

unsatisfactory performance has been given as the reason for the move away from LOA units.

4.5.2 Operation and Maintenance Practices

The vapor processors designed for VOC control at bulk gasoline terminals require regular maintenance attention in order to consistently achieve the emission limit for which they are designed. Proper maintenance for these units generally includes frequent (at least daily) visual inspections in order to monitor component operation, fluid levels, warning lights, pressures, temperatures, presence of leaks, and other miscellaneous items. Manufacturers frequently supply inspection checklists to facilitate these routine checks, and some terminals have developed individual lists for their own use. Most terminals incorporate such inspections into the normal duties of their maintenance personnel, which include routine checks of loading racks, storage tanks, pumps, and other terminal equipment. Of course, the inspections themselves do not maintain the proper operation of vapor processors, but any necessary repairs indicated through atypical readings, sounds, etc., can be implemented rapidly to minimize downtime.

Each type of vapor processor has different maintenance requirements due to varying system size and complexity, types of components, and operating time and sequencing. Refrigeration systems require daily checks of several subsystems and components. Defrost system pump pressure, as well as fluid levels and temperatures, should be checked regularly. Oil levels, pressures, and temperatures in the precooler and refrigeration systems require regular inspection. Liquid recovery meters and condenser coil temperature records on some units indicate the level of performance of the units. Maintenance on carbon adsorption sytems includes checks of cycle timing and bed vacuum and temperatures. Elapsed system operation time meters on some systems provide an indication of proper system operation and can indicate maintenance intervals. Maintenance of thermal oxidation systems may include daily observation of the activation sequence and inspection of pilots and burners. Sight ports are generally provided so that the condition of the flame can be observed. Vapor holders in these systems should be frequently inspected for leaks, and the high and low level switches checked for proper operation. All vapor processors are provided with indicator panels to warn of malfunctions, and most have automatic shutdown or interlock systems. These systems provide automatic indication that maintenance attention may be required. The annual costs to maintain vapor processing systems, including routine inspections and the expected typical repair costs, have been considered in determining the cost impact on affected terminals (Section 8.2.2.2 of Chapter 8).

4.6 EMISSIONS DUE TO GASOHOL LOADING

The single most important problem confronting control of VOC when gasohol is used as fuel instead of gasoline is increased vapor pressure. An RVP increase from 8.7 psia to 9.8 psia by the addition of 10 percent by volume of ethanol to gasoline is a vapor pressure increase of 12.5 percent. Assuming ideal saturated vapors at 100°F, the VOC content would be 59 volume percent in the vapor space of a gasoline tank and 67 volume percent in a tank containing gasohol. Thus, VOC concentrations entering vapor control systems would be higher for gasohol because of the increased vapor pressure of the fuel. To maintain the status quo with respect to VOC emissions from gasoline marketing, maintenance activities could be increased to minimize leaks from vapor handling and transfer equipment.

Ethanol is known to increase the rate of gum formation in blends during storage, so that these blends may loosen existing gum-bound deposits of rust and other sediment.[16] When existing fuel handling systems are first converted from gasoline to an alcohol blend, certain operational problems may arise. These problems are expected to diminish with continued use of gasohol.

The specific effects of gasohol on the operation and efficiency of either a carbon adsorption or a refrigeration system have not been ascertained. Some factors which may have an effect on the performance of these control systems include:

> The heat of vaporization is substantially higher for ethanol than for the other hydrocarbons. This may result

in some localized heating when ethanol is adsorbed, serving to desorb some of the hydrocarbons prematurely.

- If some water is present in the gasohol, phase separation may occur. In a refrigeration system this ethanol/water phase may be subject to freezing.
- Over twice as much heat removal is required to condense ethanol as compared to other gasoline components.

At best, there is presently only scattered data in the literature. Pilot testing by control equipment manufacturers has not yet been initiated. However, several manufacturers have stated that gasohol vapors should not have a significant impact on the operating efficiency of the vapor processing systems.[17,18,19,20,21,22]

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5.0 MODIFICATION AND RECONSTRUCTION

In accordance with Section 111 of the Clean Air Act, as amended in 1977, standards of performance must be established for new sources within a stationary source category which "... may contribute significantly to air pollution ...." Standards apply to operations or apparatus (facilities) within a stationary source, selected as "affected facilities;" that is, facilities for which applicable standards of performance have been promulgated and the construction or modification of which commenced after the proposal of the standards.

On December 16, 1975, the Agency promulgated amendments to the general provisions of 40 CFR Part 60, which included revisions to clarify the terms "modification" and "reconstruction." Under the provisions of 40 CFR 60.14 and 60.15, an "existing facility" may become subject to standards of performance if deemed modified or reconstructed. An "existing facility," defined in 40 CFR 60.2, is an apparatus of the type for which a standard of performance is promulgated and the construction or modification of which was commenced before the date of proposal of that standard. The following discussion examines the applicability of these provisions to bulk gasoline terminals and details conditions under which existing facilities could become subject to standards of performance. It is important to stress that since standards of performance apply to affected facilities which, combined with existing and other facilities, comprise a stationary source, the addition of an affected facility to a stationary source through any mechanism (new construction, modification, or reconstruction) does not make the entire stationary source subject to standards of performance, only the added affected facility.

5.1 40 CFR PART 60 PROVISIONS FOR MODIFICATION AND RECONSTRUCTION

5.1.1 Modification

It is important that these provisions be fully understood prior to investigating their applicability.

Modification is defined in §60.14 as follows:

> Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of Section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

Paragraph (e) lists certain physical or operational changes which will not be considered modifications, irrespective of any change in the emission rate. These changes include:

1. Routine maintenance, repair, and replacement,
2. An increase in the production rate not requiring a capital expenditure as defined in §60.2,
3. An increase in the hours of operation,
4. Use of an alternative fuel or raw material if, prior to the standard, the existing facility was designed to accommodate that alternate fuel or raw material,
5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or replaced by a system considered to be less environmentally beneficial.

Paragraph (b) clarifies what constitutes an increase in emissions in kilograms per hour and the methods for determining the increase, including the use of emission factors, material balances, continuous monitoring systems, and manual emission tests. Paragraph (c) affirms that the addition of an affected facility to a stationary source does not make any other facility within that source subject to standards of performance. Paragraph (f) simply provides for superseding any conflicting provisions. Paragraph (g) stipulates that compliance with all applicable standards will be achieved within 180 days of the completion of any modification.

5.1.2 Reconstruction

Reconstruction is defined in §60.15 as follows:

> "Reconstruction" means the replacement of components of an existing facility to such an extent that: (1) the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards set forth in this part.

When the replacement of components has reached the 50 percent level, the source is identified for consideration as a reconstructed source. The Administrator determines whether the replacement constitutes reconstruction. If so, the source becomes an affected facility irrespective of any change in emissions.

As stated in §60.15(f), the Administrator's determination of reconstruction will be based on:

> (1) The fixed capital cost that would be required to construct a comparable new facility; (2) the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; (3) the extent to which the components being replaced cause or contribute to the emissions from the facility; and (4) any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

The purpose of the reconstruction provision is to ensure that an owner or operator does not perpetuate an existing facility by replacing all but minor components, support structures, frames, housing, etc., rather than totally replacing it in order to avoid being subject to applicable standards of performance.

5.2 APPLICABILITY TO BULK GASOLINE TERMINALS

5.2.1 Modification

Investigation of the bulk gasoline terminal industry has shown that there are several changes, either physical or operational, applicable to the affected facility which might qualify as a modification. There are, also, potential actions which may result in an increase in emissions from the bulk gasoline loading operations but might not be considered modification to existing gasoline loading racks.

5.2.1.1 Equipment Relocation and Change in Ownership. The relocation of an existing loading facility within the terminal would not constitute a modification. This would require the use of essentially all the same components of the existing rack at the new location. Change in ownership of an existing bulk gasoline terminal would not cause the facility to become an affected facility under the NSPS.

5.2.1.2 Removal or Disabling of a Control Device. The intentional removal or disabling of an emission control device servicing an existing gasoline loading operation would be considered a modification. This includes the replacement of an existing control device with one that is less environmentally beneficial (§60.14(e)(5)).

5.2.1.3 Addition of a Vapor Recovery System. The addition or use of any system or device whose primary function is the reduction of air pollutants is not, by itself, considered a modification under §60.14. For example, the addition of a vapor processing unit to control VOC emissions from gasoline loading operations at a terminal would not be considered a modification under §60.14(e)(5).

5.2.1.4 Addition or Expansion of Loading Racks. An increase in throughput without a capital expenditure does not constitute a modification under §60.14(e)(2). A capital expenditure, as defined in §60.2, means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowable percentage" specified in the latest edition of Internal Revenue Service Publication 534 and the existing facility's basis, as defined by Section 1012 of the Internal Revenue Code.

The addition or expansion of loading racks is normally done at the terminal to accommodate new products, to allow for greater throughput of existing products, or to ease traffic delays during peak loading periods. The accommodation of new products and the increase in throughput of existing products could increase emissions at the loading racks. Since the additions and expansions to the loading racks would most likely be considered a capital expenditure, the additions and expansions might constitute a modification.

In some cases, the overall daily throughput may not change due to rack expansions. However, the peak hourly loading rate may increase because more trucks are able to load at one time. In these cases, the hourly emissions would increase. Since this throughput and emissions increase would be coupled with a capital expenditure, these additions or expansions might constitute a modification.

5.2.1.5 Loading Rack Conversions. Gasoline loading rack conversions might be considered a modification if emissions increased. This type of conversion could include top-to-bottom loading conversions if the throughput were to increase enough to offset the emission reduction expected from the change to bottom loading. The top-to-bottom loading conversion would be considered a capital expenditure; therefore, the increase in throughput coupled with an increase in emissions would not be exempt from modification under §60.14(e)(2).

5.2.2 Reconstruction

A facility is considered, under §60.15, for reconstruction determination when the fixed capital cost of the alteration exceeds 50 percent of the fixed capital cost required to construct an entirely new facility. Once the facility has been identified for consideration, it is up to the Administrator to review the information and determine if the facility alteration constitutes a reconstruction (§60.15(e)). An existing facility, upon reconstruction, becomes an affected facility regardless of any change in the emission rate.

5.2.2.1 Top-to-Bottom Loading Conversions. Top loading to bottom loading conversions will normally exceed the 50 percent cost to construct an entirely new loading rack; therefore, the facility would become eligible for reconstruction assessment. Top loading to bottom loading conversions have been performed both with and without accompanying vapor recovery installations. Projects have also included top loading vapor recovery system conversions to bottom loading vapor recovery systems.[1,2] The Administrator would determine on a case-by-case basis whether these conversions would constitute a reconstruction. The extent to which the components being replaced contribute to the facility emissions is taken into account by the Administrator in the determination of reconstruction (§60.15(f)(3)).

The 50 percent capital cost figure for reconstruction is considered on a cumulative basis. This is independent of the time span required to complete the reconstruction projects.

5.2.2.2 Replacement and Repair of Loading Rack Equipment. A facility is identified for reconstruction determination when the fixed capital cost of the replacement items or required repairs exceed 50 percent of the fixed capital cost of constructing an entirely new facility.

Replacement or unscheduled major repairs of loading rack equipment, such as loading arms, pumps, or meters, may not by themselves exceed the 50 percent replacement cost of a new facility. However, since the 50 percent replacement cost is a cumulative figure, these unscheduled major repairs and replacements would be included in reaching the 50 percent criterion.

Normal maintenance items, however, are not included in the determination of the 50 percent replacement cost criterion. Items which would require normal scheduled repairs would include pump seals, meter calibrations, loading arm gaskets and swivels, coupler gaskets, and overfill sensors. Items which typically require scheduled replacement under a normal maintenance program would include vapor hoses and grounding cables at the loading rack.[3,4]

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6.0 MODEL PLANT PARAMETERS AND REGULATORY ALTERNATIVES

6.1 INTRODUCTION

This chapter defines model bulk gasoline terminals and alternative approaches considered for regulating VOC emissions from bulk gasoline terminals. The model plant parameters were selected to represent the range of new and existing bulk gasoline terminals and provide a basis for comparison of environmental and economic impacts of the regulatory alternatives. The selected alternatives provide for varying limits of control for VOC emissions from the gasoline loading operations.

In order to characterize the for-hire tank truck industry and to determine the economic impact of the regulatory alternatives on this vital segment of the gasoline distribution system, model firm parameters were also developed for the motor carrier companies delivering gasoline from bulk terminals. These parameters were selected to represent the existing range of company sizes.

6.2 MODEL PLANT PARAMETERS

The process for selecting the model plant parameters for bulk terminals involved defining a bulk gasoline terminal, designating an affected facility, and finally selecting the model plant parameters. The data base for determination of the model plant parameters was derived from operating data on 40 terminals of various sizes and ages. Parameters for the for-hire motor carrier company model firms were determined using the most recent industry reports and census data.

6.2.1 Definition of a Bulk Gasoline Terminal

A bulk terminal is generally any wholesale marketing facility which receives refined petroleum products from an outside source, stores them in aboveground tanks, and delivers them in tank trucks to customers. Two criteria were considered in arriving at the definition of bulk gasoline terminal utilized in this report. The first involves the terminal's gasoline throughput, and the second involves the mode of delivery of gasoline to the terminal. Throughput is variable for a given facility and could lead, in the case of smaller facilities, to a shifting definition status based on business volume. The mode of delivery criterion would define a terminal as any wholesale marketing outlet which receives product by pipeline, ship, or barge. This definition would distinguish terminals from bulk plants since the bulk plants receive product almost exclusively by truck. Rail car deliveries were not included in the mode of delivery definition for the terminals. Rail car deliveries are made to bulk plants more often than to terminals and, therefore, would not distinguish the wholesale facility as a terminal. Therefore, a terminal is defined as a wholesale petroleum marketing outlet which receives product by pipeline, ship, or barge.

6.2.2 Designation of Affected Facility

Loading rack facilities in the bulk terminal industry can vary widely in types and quantities of products handled. In addition to gasoline, large quantities of fuel oil, diesel, and jet fuel may be handled by a terminal. This variation in products handled is due to the demand for each product in the vicinity of the terminal. Due to low vapor pressures, the emissions from fuel oil, diesel, and jet fuel are considered low when compared to gasoline, and so these products would not be regulated by the proposed standards.

At many terminals, "switch loading" takes place (Section 3.2.3.1). Switch loading is the practice of carrying various products in the delivery tank on successive deliveries. Switch loading can cause uncontrolled VOC emissions to be displaced to the atmosphere. For example, fuel oil loaded into a delivery tank which had carried a previous load of gasoline would displace gasoline vapors to the atmosphere. To control these emissions, switch loading was taken into account in designating the affected facility. Consequently, the proposed standards would affect both the loading of gasoline into delivery tank trucks and the loading of any liquid product into tank trucks which contain gasoline vapors (defined as gasoline tank trucks).

Because vapor leakage from tank trucks can contribute significantly to the total VOC emissions which occur during liquid product loading (Section 3.2.3.3.1), three alternative approaches to designating the affected facility which would take into account these leakage emissions were considered.

Under the first approach, the standards would apply only to the bulk terminal. The terminal owner or operator would be required to use vapor collection equipment on loading racks servicing gasoline tank trucks, and to restrict loadings to vapor-tight tank trucks. The affected facility under this approach would include only the loading racks servicing gasoline tank trucks. Operators of gasoline tank trucks wishing to load at the terminal would need compatible loading and vapor recovery equipment, and vapor-tight delivery tanks. This approach would consolidate responsibility for controlling emissions without resulting in an excessive burden for the terminal owner or operator.

Under the second approach, standards would apply directly to both the terminal and the tank trucks. The standards would require the terminal owner or operator to install vapor collection equipment and the tank truck operator to have compatible equipment and vapor-tight tank trucks. Under this approach, the affected facility would consist of the combination of the loading rack and the truck-mounted tank, with a single standard covering the hybrid loading rack/tank facility. The second approach could result in several owners or operators (of the terminal and of the tank trucks) at the same terminal being regulated under a single standard. This could create enforcement difficulties and problems in determining liability.

The third approach would involve designating two affected facilities, one consisting of the loading racks servicing gasoline tank trucks and the other consisting of the truck-mounted tanks, and applying a separate standard to each facility. It would not be practical to directly regulate gasoline tank trucks under a separate standard because the VOC emissions being regulated occur only during product loading at the terminal, and a situation of two standards regulating the same source of emissions would result. Furthermore, in the case of new tank trucks loading at an existing uncontrolled bulk terminal, only the tank trucks would be regulated, and VOC emissions would be displaced to the atmosphere uncontrolled since the terminal would have no vapor collection or control equipment to process the vapors. Thus, separate standards would not be effective in these circumstances.

After consideration of the issues involved with each of these approaches to designating the affected facility, the first approach was selected as the most practical of the three possibilities. This would place direct responsibility under the proposed standards on the owner or operator of the bulk terminal only, would eliminate the potential for enforcement problems associated with an impermanent affected facility under the second approach, and would eliminate the situation of regulating the same operation with two standards under the third approach.

Two potential affected facility designations under the first approach were examined. These were: (1) each individual loading rack, and (2) the combination of all the loading racks at the terminal which service gasoline tank trucks. Both of these designations would exclude loading racks which load only non-gasoline products into tank trucks which do not handle gasoline. Since the purpose of Section 111 is to minimize emissions by application of the best demonstrated control technology at all new and modified sources (considering cost, other health and environmental effects, and energy requirements), there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources within plants will be brought under the coverage of the standards as they are installed.

While selection of a narrower designation of affected facility generally results in greater emissions reduction by earlier coverage of replacement equipment, it appears that a broader designation could result in greater emissions reduction in the bulk gasoline terminal industry. Replacement of existing racks is not expected to occur to any great extent, because properly maintained racks do not generally require replacement. In other words, the isolated replacement of a single rack due to deterioration of that rack is expected to occur only rarely. Information from industry indicates that terminals will concentrate on additions of new racks to sets of existing racks rather than replacement of existing racks. It further appears that if replacement does occur, it will involve a major change in the rack system (such as conversion from top to bottom loading) and will involve most or all of the racks at the terminal rather than just one rack. The reasons that a total racks affected facility designation is expected to result in greater emission reduction than a single rack affected facility designation, in the situations described above, are explained below.

Under modification (Section 5.1.1 of Chapter 5), if a new rack were added to a terminal it would be an affected facility under a single rack designation, and only that rack would be covered. Under a total racks designation, the addition of a single new rack could result in a modification, in which case all of the racks would become an affected facility, resulting in greater emission reduction under this designation. Even if the addition of the new rack did not result in a modification because there was no increase in emissions (due to partial control, for example), the total racks designation would still result in less emissions. This is because the single rack designation would still result in a small incremental emissions increase even if the rack were controlled.

In addition to modification, an existing facility could become reconstructed (Section 5.1.2 of Chapter 5) if the fixed capital cost of replacing components at that facility exceeded 50 percent of the cost of a comparable entirely new facility. Under a single rack designation, this cost figure could be attained sooner for a given rack than it would under a total racks designation, since total replacement cost for parts for a single rack would be less than for all the racks, and 50 percent of the cost for a single new rack would be less than 50 percent of the total cost for all new racks. However, under a total racks designation, all the racks at a terminal could become affected facilities if the conversion cost exceeded 50 percent of the cost needed to build all new racks; although more racks would have to be converted to attain this cost, more racks could eventually be covered sooner than they would be under a single rack designation. Multiple-rack conversion projects are the most likely type of replacement at bulk terminals, and often take from 1 to 2 years to complete. Therefore, considering that work on several racks is expected to be more frequent than single rack replacement, and that more racks would be affected under the total racks designation, it is projected that the total racks designation would result in more emission reduction than would the single rack designation.

An examination of the control costs presented in Sections 8.2.2 and 8.2.3 of Chapter 8 indicates that the cost to a terminal owner or operator would most often be less under a total racks designation of the affected facility. For existing terminals which do not already have control systems installed due to SIP regulations, the net annualized cost of operating a system controlling all the racks would be lower than for a system controlling just one rack. This is due to the increased product recovery cost credits resulting from controls on all racks. Terminals installing thermal oxidation systems would not enjoy this cost benefit, however, because no product is recovered in these systems. For terminals which already have control systems under SIP regulations, under a single rack designation a separate control system may have to be installed to control a single new rack. However, under a total racks designation, an owner or operator would have several options for control, including replacing, adding onto, or upgrading the existing system in order to control all racks and meet the emission limit of the standards. The cost tables in Section 8.2.3 indicate that any of the options under the total racks designation would be less expensive than installing a separate control system to control a single rack under the single rack designation.

In addition to the emission reduction and cost considerations discussed above, the single rack designation has technical complications. Performance testing of this affected facility would be difficult at terminals which already have some means of vapor control installed (estimated to include about 70 percent of the existing terminals). If one rack were newly installed or altered in such a way as to become an affected facility under modification or reconstruction provisions and were required to meet a more stringent emission limit, the new rack could require controls different from the remainder of the loading equipment. Since the emissions from all of the racks are typically routed to the single vapor processor, it would be impossible to distinguish the vapor processor outlet emissions originating from only the new loading rack. If an existing control device were unable to meet a more stringent emission limit, a bulk terminal operator could either install a separate vapor collection system and processor for the new rack, or replace or upgrade the existing control device. The latter approach is identical to what a total racks designation of the affected facility would accomplish.

The foregoing discussion indicates that the total racks designation would result in the greatest emission reduction and the lowest cost to the owner or operator of a bulk terminal. Performance testing of this facility would be straightforward because all loading racks would be subject to the same standards. Consequently, due to the considerations outlined above, the designation which includes the combination of all the loading racks servicing gasoline tank trucks was selected as the affected facility for regulation under the proposed standards.

6.2.3 Data Base for Model Plant Parameters

Data presented in reports of EPA-sponsored terminal source tests, data from plant visits, and data from information requests submitted under authority of Section 114 of the Clean Air Act were used as input for the selection of the terminal model plant parameters.[2-36] The data are summarized in Table 6-1. Information in Table 6-1 is given for the type of facility (either new or existing), gasoline throughput, gasoline storage, and gasoline loading rates. Additional sources were consulted for tank truck capacity data and method of loading.[37,38,39]

Model firm parameters for the gasoline motor carrier industry relied primarily on tank truck population data from the Bureau of the Census.

6.2.4 Model Plant Parameters for Bulk Gasoline Terminals

Since terminal gasoline throughputs are distributed over a wide range, several model plant sizes were considered in order to best represent the industry. A recent EPA-sponsored report[40] discussed the distribution of gasoline terminals by throughput within the industry. It was estimated that the size distribution of new and proposed terminals would closely resemble the distribution of existing facilities. Almost 50 percent of the existing terminals are less than 757,000

Table 6-1. DESIGN PARAMETERS FOR BULK GASOLINE TERMINALS[a]

Facility	Terminal Type	Throughput (liters/Day)	Gasoline Storage: Total Capacity (10^3 m^3)	Gasoline Storage: Number of Tanks	Gasoline Loading: Number of Positions	Gasoline Loading: Number of Arms	Gasoline Pumping Rate (LPM)	Maximum Instantaneous Pumping Rate (LPM)
1	N[b]	318,000	--[c]	2	2	4	2,270	9,100
2	E[d]	757,000	--	3	2	6	1,700	11,400
3	E	1,900,000	--	4	3	9	2,460	14,800
4	E	606,000	--	4	2	6	2,650	15,900
5	E	1,817,000	36	6	4	11	1,890	--
6	N	1,514,000	--	--	4	12	2,460	19,700
7	E	1,514,000	--	--	2	6	3,400	20,400
8	E	303,000	--	4	2	6	1,800	7,570
9	E	606,000	--	--	3	9	--	--
10	E	341,000	--	--	1	3	--	--
11	E	1,419,000	--	--	2	6	--	--
12	E	1,101,000	--	--	3	6	2,270	--
13	E	814,000	--	--	3	6	2,080	--
14	E	---	--	--	3	9	2,650	--
15	E	1,514,000	--	--	3	9	2,270	--
16	E	927,000	--	6	3	8	2,270	20,400
17	E	189,000	6	4	1	3	2,080	4,160
18	E	---	--	5	2	8	--	--
19	E	1,514,000	--	--	6	18	2,270	--
20	E	757,000	27	4	2	8	2,650	--
21	N	1,571,000	70	6	3	9	--	--
22	N	5,045,000	144	15	4	--	--	--
23	N	2,330,000	--	--	--	--	--	--

Table 6-1. DESIGN PARAMETERS FOR BULK GASOLINE TERMINALS[a] (Concluded)

Facility	Terminal Type	Throughput (liters/Day)	Gasoline Storage: Total Capacity (10^3 m^3)	Gasoline Storage: Number of Tanks	Gasoline Loading: Number of Positions	Gasoline Loading: Number of Arms	Gasoline Pumping Rate (LPM)	Maximum Instantaneous Pumping Rate (LPM)
24	E	1,190,000	--	--	4	--	--	--
25	E	870,000	9	3	2	5	2,650	4,540
26	E	870,000	28	--	--	--	--	5,680
27	E	814,000	29	5	2	--	--	5,680
28	E	--	29	4	2	6	2,080	--
29	N	2,040,000	68	--	2	--	--	--
30	E	1,980,000	53	5	5	--	2,080	--
31	E	--	--	--	2	6	1,890	3,790
32	E	2,270,000	--	--	2	6	3,410	20,400
33	N	1,514,000	23	3	4	10	2,840	--
34	E	1,514,000	--	--	3	9	2,460	22,100
35	E	1,514,000	--	--	5	--	--	--
36	E	757,000	--	--	5	15	2,270	--
37	E	606,000	16	3	2	6	1,890	--
38	E	1,003,000	25	3	2	12	2,270	68,100
39	E	280,000	8	3	1	3	2,840	--

[a]References: 2-36.
[b]N = New terminal (includes terminals less than 2 years old).
[c]No data.
[d]E = Existing terminal.

liters per day (LPD) so a model plant size of 380,000 LPD was selected to represent this subset. Approximately 30 percent of the gasoline terminals have throughputs between 757,000 and 1,514,000 LPD. A model plant with a throughput of 950,000 LPD was selected to cover plants in the range of 660,000 to 1,420,000 LPD. An additional 20 percent of the terminals have throughputs between 1,514,000 and 2,270,000 LPD. A model plant size of 1,900,000 LPD was selected to represent these facilities.

Although the report indicates that less than 5 percent of the existing terminals are greater than 2,270,000 LPD, information gathered on new or proposed terminals indicates that a significant percentage of new terminals will be larger than 2,270,000 LPD. Data on proposed terminals in Florida indicate one over 2,270,000 LPD and one over 4,900,000 LPD.[36] A model plant size of 3,800,000 LPD was selected to represent these terminals. Existing terminals can be best represented by the three lower size ranges (380,000 LPD, 950,000 LPD, and 1,900,000 LPD) while new or proposed terminals are best represented by the three larger categories (950,000 LPD, 1,900,000 LPD, and 3,800,000 LPD). Model plant parameters for the four selected size categories of 380,000 LPD, 950,000 LPD, 1,900,000 LPD, and 3,800,000 LPD, are presented in Table 6-2.

The model plant parameters present data for several design factors, many of which were derived from Table 6-1. The data for gasoline storage, gasoline loading configurations, and pumping rates were grouped by size ranges and an average was calculated. Where data were lacking for the largest terminal size, parameters were extrapolated from the other categories. For example, the data on the number of loading arms and racks for the 3,800,000 LPD terminal was not complete; however, a value was extrapolated from the other size ranges and also from previous visits to terminals of this size in California.

The average gasoline pumping rate was the same for each of the three lower categories and was independent of throughput. Therefore, the same average pumping rate (2,270 liters per minute) was assumed for the 3,800,000 liters per day plant. The maximum instantaneous pumping rate was calculated by assuming three loading arms operating simultaneously from each of the loading positions or racks.

Table 6-2. BULK GASOLINE TERMINAL MODEL PLANT PARAMETERS

Design Factor	1	2	3	4
a. Gallons per Day	100,000	250,000	500,000	1,000,000
b. ℓ/Day	380,000	950,000	1,900,000	3,800,000
c. Number of Rack Positions for Gasoline	2	3	3	4
d. Number of Loading Arms for Gasoline	6	9	9	12
e. Loading Method	Submerged (Top or Bottom)	Submerged (Top or Bottom)	Submerged (Top or Bottom)	Submerged (Top or Bottom)
f. Pumping Rate/Loading Arm	600 GPM (2,270 LPM)	600 GPM (2,270 LPM)	600 GPM (2,270 LPM)	600 GPM (2,270 LPM)
g. Tank Truck Capacity	8,500 Gallons (32,200 Liters)	8,500 Gallons (32,200 Liters)	8,500 Gallons (32,200 Liters)	8,500 Gallons (32,200 Liters)
h. Tank Truck Loading Time	20 minutes	20 minutes	20 minutes	20 minutes
i. Maximum Instantaneous Loading	3,600 GPM (13,600 LPM)	5,400 GPM (20,400 LPM)	5,400 GPM (20,400 LPM)	7,200 GPM (27,300 LPM)
j. Operating Schedule	340 Days/Year	340 Days/Year	340 Days/Year	340 Days/Year
k. Gasoline Storage Capacity	65,000 Bbl (10,340 m^3)	150,000 Bbl (23,880 m^3)	275,000 Bbl (43,670 m^3)	600,000 Bbl (95,400 m^3)
l. Number of Storage Tanks for Gasoline	3	4	5	6
m. Number of Terminal-Operated Trucks	3	6	9	20

The method of loading was derived from operator interviews, Section 114 letter responses, and the literature. The industry trend is toward bottom loading, and it is expected that all new terminals will be bottom loaded. There are a number of top loading systems still in operation at existing terminals, and it was assumed for the model plants that these would be submerged loaded. The trend is toward submerged loading as a minimum emission control and cost-saving measure at terminals where top loading is still in operation.

The average tank truck capacity was determined by consulting the EPA tank truck and rail car survey.[39] The capacities of over 1,000 tank trucks were considered to obtain an average of 32,200 liters (8,500 gallons). The average number of tank trucks per terminal was determined from plant visits and Section 114 letter responses. A number of terminal operators stated that they do not operate any terminal-owned tank trucks. However, a majority of the respondents indicated that the terminals do operate their own tank vehicles.

The operating schedule for the terminals was also based upon operator interviews and Section 114 letter responses. Of those responding, there were equal numbers operating six days per week and seven days per week. A value of 6.5 days per week was used to establish an average work year of 340 days per year.

6.2.5 Model Firm Parameters for For-Hire Tank Truck Companies

The independent trucking companies which own or lease tank trucks used for transporting gasoline from bulk terminals will be affected by some of the regulatory alternatives discussed in Section 6.3. The tank trucks operating at an affected facility will be required to be compatible with the loading method (usually bottom loading) and vapor collection equipment which the terminal has installed to limit VOC emissions. In order to take into account the economic impact of the regulatory alternatives on these companies, model firm parameters have been developed. These parameters are intended to characterize the existing range of company sizes as determined from the most recent available information. They are further meant to be similar to and serve the same purpose as the model plant parameters for bulk terminals.

The primary source of data used to derive the parameters was the 1977 Census of Transportation, Truck Inventory and Use Survey, conducted by the Bureau of the Census.[41] This survey is based on a stratified probability sample of about 117,000 trucks, drawn from an estimated 28 million registrations on file in the 50 States and the District of Columbia during 1977. The data file was acquired in the form of a machine-readable tape, and a printout containing the desired data format was generated. The data analysis was limited to tank vehicles carrying petroleum or petroleum products listed under the wholesale and for-hire use categories. In addition, only tanks of greater than 15,100 liter (4,000-gallon) capacity were considered, in order to avoid the inclusion of small tank vehicles operating only at bulk plants. These limitations provided a population sample of 500 tanks. It is important to note that since information specific to gasoline tank trucks at terminals is not available, the assumption that petroleum tank vehicles of greater than 15,100 liter capacity are representative of terminal gasoline tank trucks was necessary. It is believed that this assumption provides a reasonably accurate profile of the industry of interest.

For each tank vehicle listed in the census survey, information was provided by respondents concerning the number of trailers, tractors, and other trucks at the same operational base. The model year and number of annual miles was shown for each vehicle listed, and these provided a breakdown by age category as well as an average number of miles driven. The number of tank vehicles assigned to each firm represents the approximate midpoint of a range of values. The smallest model firm represents companies with from one to three tanks at a single base of operations, and this firm is considered to operate two tank vehicles. The next model firm operates from 4 to 10, or 7 tanks, the third firm operates from 11 to 50, or 30 tanks, and the largest model firm operates more than 50, or 100, tank vehicles.

The average number of employees for each model firm size was determined from a recent Motor Carrier Annual Report.[42] Average tank capacity was assumed to be the same as that derived for terminal-owned tank trucks (Table 6-2). The model firm parameters for the for-hire motor carrier companies operating at bulk terminals are summarized in Table 6-3. Industry characterization, costs, and economic impact are discussed in Sections 8.1.3, 8.2.5, and 8.4.2, respectively, of Chapter 8.

6.3 REGULATORY ALTERNATIVES

Four regulatory alternatives were selected for consideration in controlling VOC emissions from bulk gasoline loading facilities at terminals. The units of the regulatory alternatives, milligrams per liter, were chosen to be consistent with the existing Control Techniques Guideline (CTG) document on bulk gasoline terminals. These units indicate milligrams of VOC emitted to the atmosphere per liter of gasoline dispensed. These units are for comparison purposes and do not necessarily reflect the units of the final proposed standard.

6.3.1 Vapor Leakage from Tank Trucks

Tank truck vapor leakage can vary significantly from terminal to terminal and from truck to truck. EPA test data indicate that leakage varied from 0 percent to 100 percent for individual truck loadings and averaged 30 percent leakage for all EPA tests. The potential quantity of emissions and the variability in this vapor tightness from terminal to terminal prompted EPA to consider controlling tank truck leakage to make terminal controls more effective. A CTG for tank trucks was published in December 1978.[43] EPA also considered controlling tank truck leakage in the development of new source standards for terminals. Testing on tank trucks in areas with vapor tightness regulations has demonstrated an average of 10 percent vapor leakage from the trucks. Section C.1.4 of Appendix C contains details on these tests. Tank truck leakage could be reduced by requiring the terminal operator to restrict loadings of gasoline tank trucks to those which have passed an annual vapor-tight test. Such a regulation would require that written verification of a tank's vapor-tight condition be carried on the vehicle at all times, and that a copy be on file at the affected terminal office.

The owner or operator of a bulk terminal would be legally responsible for reducing emissions from that terminal. However, he might not have direct control or financial responsibility over all tank trucks that

Table 6-3. TANK TRUCK COMPANY MODEL FIRM PARAMETERS

Firm Parameter	1	2	3	4
a. Number of Tank Vehicles[a]	2	7	30	100
b. Vehicle Age Distribution[b]				
Pre-1967	0	1	3	9
1967-1975	1	5	22	74
1976-1978	1	1	5	17
c. Number of Tractors	2	7	24	75
d. Number of Other Trucks	5	10	12	15
e. Annual Tank Vehicle Miles (Kilometers)	65,000 (104,000)	65,000 (104,000)	65,000 (104,000)	65,000 (104,000)
f. Tank Capacity in Gallons (Liters)	8,500 (32,200)	8,500 (32,200)	8,500 (32,200)	8,500 (32,200)
g. Number of Employees	10	25	50	120

[a]Number of straight truck or trailer tank vehicles at a single operational base.
[b]Quantities approximate. Further discussion in Section 8.1.3 of Chapter 8.

load there. Consequently, it would be unfair to require the owner or operator to maintain all tank trucks free from emission leakage. Therefore, in order to avoid such a situation, the regulatory alternatives would only require the terminal owner or operator to load gasoline tank trucks which had demonstrated compliance with a vapor-tight requirement, as opposed to requiring him to maintain all gasoline tank trucks loading at the terminal in a vapor-tight condition.

6.3.2 Selection of Emission Limits

The VOC emission test results discussed in this section are adjusted values which take into account tank truck vapor leakage. The results were adjusted to allow the evaluation of all vapor processors on an equivalent leak-free basis. The test method used in the EPA testing program required that the volume of vapors returned to the system be measured. The tank trucks are also checked to see if they fit the definition of vapor-tight (no leak greater than 100 percent of the lower explosive limit). The volume of vapors returned or captured per volume of gasoline dispensed was then compared for vapor-tight and leaking tank trucks. Using this method, the average amount of vapor leakage could be determined. The mass concentration, measured at the vapor processor outlet, was then adjusted to take into account vapor leakage. This adjustment assumed the vapors which leaked would pass through the processor and be controlled at the same efficiency as the rest of the vapors. This approach was used to compare results from numerous tests on a common, no-leak basis.

Test results from 22 EPA-sponsored source tests are summarized in Section 4.5. A more detailed presentation of calculated test parameters is contained in Section C.1.2 of Appendix C.

6.3.3 Description of Regulatory Alternatives

Four alternative regulatory approaches were selected for the bulk gasoline terminal industry. The regulatory alternatives represent feasible methods of controlling VOC emissions from the gasoline loading operations at terminals. All emission limits represent actual mass emissions as measured at the outlet of the vapor processor. The control methods used as the basis for these alternatives are described in Section 4.5. Table 6-4 summarizes the regulatory alternatives

Table 6-4. REGULATORY ALTERNATIVES FOR BULK GASOLINE TERMINALS

Alternative	Description
I (Baseline)	No additional controls over those included in the State Implementation Plans (SIP), which limit emissions to 80 mg/liter from tank truck loading and require tank truck leakage controls in regulated areas.
II	Controls to limit gasoline loading emissions to 80 mg/liter and to require tank truck leakage controls at affected facilities.
III	Controls to limit gasoline loading emissions to 35 mg/liter with no tank truck leakage controls beyond the SIP coverage.
IV	Controls to limit gasoline loading emissions to 35 mg/liter and to require tank truck leakage controls at affected facilities.

developed for the bulk gasoline terminal industry. The four regulatory alternatives are described in detail in the following subsections.

6.3.3.1 Alternative I (Baseline Case). Under Alternative I, no NSPS would be developed. Instead, the State Implementation Plans (SIPs) would be relied upon to control VOC emissions from bulk gasoline terminals. SIP regulations generally require controls only in non-attainment areas. The SIP regulations would require controls for most areas of the United States equivalent to the CTG recommended level of 80 mg/liter from the loading operations. This would regulate approximately 70 percent of the existing facilities. This alternative also assumes that the recently published CTG recommended limits on tank truck leakage would be implemented in the same areas where the terminal CTG recommendations were adopted. This assumption was based upon the best estimate available to EPA's Control Programs Development Division (CPDD). Those areas not covered by CTG equivalent regulations were divided into areas where no regulations apply and areas where just submerged fill applies. A discussion of these regulatory coverage areas is given in greater detail in the section on Baseline Emissions (Section 3.3).

6.3.3.2 Alternative II. This alternative would require controls on new, modified, or reconstructed sources that would limit VOC emissions from the vapor processor outlet to 80 mg/liter. It would also require that terminal operators restrict loadings of gasoline tank trucks to those which have passed an annual vapor-tight test. The test data indicate an average vapor collection efficiency of 70 percent (range from 50 to 99 percent) for tank trucks in areas that have no vapor-tight regulations (30 percent truck leakage). Tank trucks in vapor-tight regulated areas have been found to average 10 percent leakage (Section 6.3.1). This alternative, in effect, does not impose additional controls on new sources in the areas where SIP regulations exist. The alternative would require the terminal to have verification that tank trucks handling gasoline have passed a vapor-tight test identical to that adopted in the SIPs. The areas that would be affected would be those which were previously not controlled at the SIP level.

This would regulate modifications and reconstructions for approximately 30 percent of the existing sources and would regulate all new sources. Because of the small number of new facilities expected to be built over the next ten years (approximately ten), the major effect of this and all other alternatives would be on modified or reconstructed sources.

All of the control systems tested would be considered applicable under this standard. The possible exception would be the lean oil absorption (LOA) system. Test data indicate that any of the other control systems could meet an emission limit of 80 mg/liter.

6.3.3.3 Alternative III. This alternative would require controls for all new, modified, or reconstructed sources to limit VOC emissions from the vapor processor outlet to 35 mg/liter. The carbon adsorption systems and thermal oxidation systems with vapor holders gave the most consistent results in reducing VOC emissions in EPA tests. The carbon adsorption average emissions were slightly lower, but the cost analysis indicated that the thermal oxidation system was the most cost-effective system for small terminals. This is important since about half of the affected facilities are expected to be in the smallest model plant size. The average adjusted daily emission rate from the carbon adsorption systems and the thermal oxidation systems which used a vapor holder were 5.9 and 13.3 mg/liter, respectively. The highest emission rate from either type of system was 29.4 mg/liter. This parameter represents the calculated rate which would have occurred in a vapor-tight collection system, based on actual measured emissions and an adjustment factor representing the quantity of tank truck vapor leakage measured during testing. In order to allow a small margin above the highest measured emission level from these two types of systems, a level of 35 mg/liter was selected as the emission limit for this regulatory alternative.

The test data indicate that the carbon adsorption and thermal oxidation with vapor holder systems tested can achieve 35 mg/liter. In the two tests on thermal oxidation systems without a vapor holder, the systems achieved this emission limit on three of six test days, indicating the potential of such a system to achieve the limit. Newer refrigeration type control units, not tested in the EPA test program, have shown the ability to meet a limit of 35 mg/liter (Section C.1.3 of Appendix C). Information from control unit manufacturers indicates that older refrigeration units may be capable of meeting this limit if operational or design modifications are made. Existing compression-refrigeration-absorption systems and compression-refrigeration-condensation systems may be able to meet the 35 mg/liter standard with the use of add-on controls.

6.3.3.4 Alternative IV. Alternative IV is similar to Alternative III in that it would limit emissions at all new, modified, or reconstructed sources to 35 mg/liter. This emission limit is based on the same control technologies discussed in the previous section. This alternative would also require the terminal owner or operator to restrict loadings of gasoline tank trucks to those which had passed an annual vapor-tight test. These additional controls over those in Alternative III would affect only those terminals in areas where tank trucks were not already regulated by SIP limitations, and are the same vapor-tight controls which would be required in Alternative II.

6.4 REFERENCES

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7.0 ENVIRONMENTAL IMPACT

This chapter presents an assessment of the environmental impacts on the bulk gasoline terminal industry associated with the regulatory alternatives described in Chapter 6. The impacts associated with air, water, solid waste, energy consumption, and other environmental concerns will be discussed in the following sections.

7.1 AIR POLLUTION IMPACTS

The air pollution impacts of regulatory alternatives for the bulk gasoline terminal industry are obtained by applying the alternative limits on new, modified, and reconstructed terminals. These emission estimates are then compared with the emissions from the terminals that would occur without the controlling standard (baseline emissions). The amount of control applied to terminals in the absence of the standard is specified by the level of control required in the State Implementation Plans (SIPs), which will cover most terminals (Section 3.3 of Chapter 3). The air pollution impact is then estimated for the bulk gasoline terminal model plants and for emissions from terminals on a national scale. For reference, the bulk terminal model plant parameters are presented in Table 6-2, and the regulatory alternatives are presented in Table 6-3 of Chapter 6.

7.1.1 Air Pollution Impact on Model Plants

The air pollution impacts on the model plants are presented in Table 7-1. Data are presented for Regulatory Alternatives II, III, and IV, and the emissions associated with each alternative. The baseline emissions (Alternative I) are also presented along with the emission reduction from the baseline for each alternative.

Three categories, which apply to each model plant, are presented in Table 7-1. These categories include terminals in non-attainment areas, and splash filled and submerged filled terminals in attainment areas. The category of terminals in the non-attainment areas

Table 7-1. BASELINE AND ALTERNATIVE VOC EMISSIONS FROM BULK GASOLINE TERMINAL MODEL PLANTS (Mg/yr)

		Alternative II		Alternative III		Alternative IV	
Model Plant (liters/day)	Baseline Emissions	Emissions	VOC Reduction[a]	Emissions	VOC Reduction[a]	Emissions	VOC Reduction[a]
Non-Attainment							
380,000	23	23	0	17	6	17	6
950,000	57	57	0	38	19	38	19
1,900,000	114	114	0	78	36	78	36
3,800,000	227	227	0	153	74	153	74
Attainment Area-Submerged Fill							
380,000	78	23	55	42	36	17	61
950,000	194	57	137	107	87	38	156
1,900,000	388	114	269	213	175	78	310
3,800,000	775	227	548	428	347	153	622
Attainment Area-Splash Fill							
380,000	186	23	163	42	144	17	169
950,000	465	57	408	107	358	38	427
1,900,000	930	114	816	213	717	78	852
3,800,000	1860	227	1,633	428	1,432	153	1,707

[a]VOC Reduction = Emissions Reduction from Baseline Emissions in Mg/yr.

includes new, modified, and reconstructed terminals. The air pollution impact of the regulatory alternatives on these terminals is the least because they will already be controlled by State air pollution regulations (see Section 3.3, Baseline Emissions). The category for submerged fill in attainment areas shown in Table 7-1 represents new terminals and modified or reconstructed existing terminals in attainment areas that incorporate submerged fill. However, the category for splash fill in attainment areas represents modified or reconstructed existing terminals only, since it is assumed that no new terminals will use splash filling. The air pollution impact is greatest in the splash fill category because the baseline VOC emissions are highest for this category of uncontrolled sources.

The emissions from terminals incorporating Alternative II are the same for all three categories, as is shown in Table 7-1. Under this alternative, all terminals would be required to restrict loadings of gasoline tank trucks to those passing an annual vapor-tight test and to limit vapor processor outlet emissions to 80 mg/liter. Since the requirements of Alternative II are identical to those imposed by the SIPs on terminals in non-attainment areas, there is no reduction in emissions from those terminals that were controlled under the baseline SIP regulations. Alternative III would require terminals to limit vapor processor outlet emissions to 35 mg/liter but would not require tank truck controls beyond those specified in the SIP regulations. Tank truck leakage would therefore continue to be uncontrolled for new, modified, and reconstructed terminals in areas where no SIP regulations exist (most attainment areas). Tank truck leakage in these areas has been estimated at 30 percent (see Section 4.3.1). By including this tank truck leakage in the emission calculations, the emissions associated with Alternative III, from terminals in the attainment area category, are higher than those associated with Alternative II. The emissions from terminals incorporating limits from Alternative IV are again identical for all categories. All terminals under Alternative IV would be required to restrict loadings of gasoline tank trucks as under Alternative II and to limit vapor processor outlet VOC emissions to 35 mg/liter. As indicated in Table 7-1, Alternative IV results in the greatest emission reductions for terminals in attainment areas.

7.1.2 National Air Pollution Impacts

The national air pollution impacts are presented in Table 7-2. The data represent total VOC emissions from terminals, in megagrams per year (Mg/yr), for the expected proposal year — 1980 (or early 1981), the SIP completion year — 1982, and the projection years — 1985 and 1990. In these estimates, 1985 is assumed to be the fifth year, and 1990 the tenth year, of the standards. Also presented are the estimated emission reductions achieved for each of the regulatory alternatives, and the percent reduction as compared to the baseline emissions.

The available data for industry growth projections are presented in Section 8.1 of Chapter 8. Data indicate that the consumption of gasoline will probably not increase significantly over the next 10 years.[1] The growth in gasoline demand will be offset by energy conservation trends and the increased gasoline efficiency for automobiles. Since it is assumed that all gasoline goes through terminals, gasoline consumption, and therefore terminal throughput, will remain fairly constant over the next 10 years. Data indicate that only approximately 10 new terminals will be built in the next 10 years. Since total throughput is not expected to increase, it is assumed that these new terminals will replace existing terminals that will close. The baseline emissions for 1982 shown in Table 7-2 are expected to remain fairly constant throughout the 1980's, because of the expected constant gasoline throughput during this period. Thus, the emission reductions indicated for 1985 and 1990 are calculated differences between total emissions in those years and a constant baseline level.

From information supplied by the industry, it is estimated that approximately 100 terminals will be modified or reconstructed over the next 10 years. It is further estimated, based upon the type of modification or reconstruction planned, that approximately 56 of these terminals will be in attainment areas and 44 will be in non-attainment areas. It is also assumed that these modifications will be performed evenly throughout the 10-year period. By using these assumptions for terminals and the emission factors found in Table 3-5 of Chapter 3, the national emission impacts have been calculated.

Table 7-2. NATIONAL AIR QUALITY IMPACTS OF REGULATORY ALTERNATIVES ON BULK GASOLINE TERMINAL INDUSTRY

	VOC Emissions, Mg/yr							
	1980	1982	1985 Alternatives			1990 Alternatives		
	Emissions	Baseline Emissions	II	III	IV	II	III	IV
Total emissions from bulk gasoline terminals	341,900	140,000	134,250	135,490	133,380	129,200	130,900	127,500
Emission reductions from baseline emissions			5,750	4,510	6,620	10,800	8,500	12,500
Percent reduction from baseline emissions			4	3	5	8	7	9
Percent Reduction For new, modified or reconstructed terminals			60	50	70	60	50	70

As discussed in the model plant section of this chapter (Section 7.1.1), the emission reduction from terminals is lowest under Alternative III. This is because tank truck leakage, not controlled in most attainment areas, is included in the emissions estimate. Alternative IV yields the greatest reduction in VOC emissions. As is presented in Table 7-2, it is estimated that by 1990 Alternative IV would reduce VOC emissions from bulk gasoline terminals by 12,500 Mg/year, or 9 percent. This reduction corresponds to an overall 70 percent reduction of VOC emissions from the 110 new, modified, or reconstructed terminals expected in the next 10 years.

The adverse air pollution impacts due to carbon monoxide (CO) and oxides of nitrogen (NO_x) emissions associated with thermal oxidation systems were also calculated. Based upon industry surveys and economic data (see Section 8.2 of Chapter 8), it was assumed that the thermal oxidation system was used as a control concept for only the small terminal model plant sizes. Hence, air pollution impacts were derived for only the two smallest model plants. Emissions were estimated using measured NO_x and CO concentrations from an EPA sponsored test.[2] The NO_x emissions would be 0.1 Mg/yr from a thermal oxidation system serving a 380,000 liter/day terminal, and would be 0.2 Mg/yr from a thermal oxidation system serving a 950,000 liter/day facility. The CO emissions would be 0.3 Mg/yr from the 380,000 liter/day terminal, and would be 0.8 Mg/yr for the 950,000 liter/day terminal. If half of the small new, modified, or reconstructed terminals (about 12 sources) were to install thermal oxidation systems (and, for worst case purposes, it was assumed that all of these terminals were in the 950,000 liter/day model plant size), the nationwide NO_x emissions would increase by about 3 Mg/yr and the nationwide CO emissions would increase by about 11 Mg/yr. For both of these pollutants, the emission increases represent a negligible adverse nationwide air pollution impact.

7.2 WATER POLLUTION IMPACT

Water is not used as a direct control medium in any of the proposed regulatory alternatives. One carbon system being developed for gasoline terminals would use a steam stripping process.[3] The water-gasoline mixture obtained in the carbon regeneration process passes into a gasoline-water separator, and the water is then discharged. The amount of steam used or water treated from this process is not known since this system is still in developmental stages.

Other systems, which cool and condense the vapors from the loading operation for liquid recovery, will also generate a gasoline-water mixture. The amount of water generated is dependent upon the relative humidity of the atmosphere. The mixture passes through a gasoline-water separator, with the gasoline returning to storage and the water being discharged. It is estimated that this will produce only a negligible negative impact on water quality.

7.3 SOLID WASTE DISPOSAL IMPACT

The disposal of discarded carbon from the carbon adsorption control systems would be the only significant source of solid waste from the control techniques considered. The worst case could be represented by all 110 new, modified, or reconstructed sources in 1990 employing carbon adsorption systems, with the carbon being discarded after its useful life at the terminal. Using an average carbon life of 10 years and an average carbon bed capacity of about 4,500 kg,[4] the total quantity of solid waste to be handled from all the terminals would be 50,000 kg per year. To put this in perspective, this is roughly equivalent to the quantity of solid waste generated each year by 1 industrial facility with 160 manufacturing employees, or the residential solid waste generated by 1,340 people. Even this worst case can be considered to represent a small negative solid waste impact.

7.4 ENERGY CONSUMPTION IMPACT

The energy consumption impacts of the control equipment discussed in Chapter 4 are presented in Table 7-3. The impacts are shown for operation of the control equipment considered for the regulatory alternatives. These include carbon adsorption (CA), compression-refrigeration-absorption (CRA), refrigeration (REF), and thermal oxidizer (TO) systems.

Energy consumption information was obtained from manufacturers, and energy recovered was based upon liquid recovery credits for each of the control systems. Recovery credits for the CRA system are lower than the CA and REF systems because of the higher average control

Table 7-3. ENERGY CONSUMPTION IMPACTS OF CONTROL EQUIPMENT ON THE BULK GASOLINE TERMINAL MODEL PLANTS

Model Plant	Energy Consumed[a,b]	Energy Recovered[a,c]	Energy Impact[a]
380,000 liters/day			
CA[d]	11,200	160,000	+ 149,000
CRA[e]	2,600	151,000	+ 148,000
REF[f]	25,000	160,000	+ 135,000
TO[g]	2,600	0	- 2,600
950,000 liters/day			
CA	16,800	399,000	+ 382,000
CRA	6,400	377,000	+ 371,000
REF	35,000	399,000	+ 364,000
TO	6,000	0	- 6,000
1,900,000 liters/day			
CA	22,600	798,000	+ 775,000
CRA	12,800	755,000	+ 742,000
REF	39,000	798,000	+ 759,000
TO	11,800	0	- 11,800
3,800,000 liters/day			
CA	28,600	1,600,000	+ 1,571,000
CRA	26,800	1,537,000	+ 1,510,000
REF	55,600	1,600,000	+ 1,544,000
TO	22,000	0	- 22,000

[a]Energy units in liters of gasoline per year.

[b]Energy consumed by the equipment per year.

[c]Gasoline recovered by equipment per year. Gasoline = 0.67 kg/liter, 35.6 MegaJoules/liter

[d]CA = Carbon Adsorption.

[e]CRA = Compression-Refrigeration-Absorption.

[f]REF = Refrigeration.

[g]TO = Thermal Oxidation.

efficiency of the CA system and the REF system. No energy recovery is indicated for the TO system since no gasoline is recovered. No other heat or energy recovery is associated with the current TO systems.

The energy impacts are positive (net energy is recovered) for the CA, CRA, and REF systems. The net energy recovered, defined in liters of gasoline per year, ranges from 135,000 liters/yr (36,000 gal/yr) for the smaller terminals to 1,571,000 liters/yr (415,000 gal/yr) for the larger terminals. This represents about 0.12 percent of the gasoline throughput for the terminals.

The TO system yields a small negative energy impact since no gasoline is recovered. Energy consumption ranges from the equivalent of 2,600 liters/yr (690 gal/yr) of gasoline for the smaller terminals to 22,000 liters/yr (5,800 gal/yr) of gasoline for the larger terminals.

The nationwide energy impacts of the regulatory alternatives, shown in Table 7-4, were derived by assuming that all VOC emissions reduction, as reported in Table 7-2, was recovered as liquid product, and that one gallon of this liquid product was equivalent to one gallon of gasoline. This assumption is considered reasonable in a vapor-tight collection and processing system; although the recovered product may not have the exact composition of gasoline, it would mix with a large quantity of gasoline in a storage tank and be available for loading into tank trucks. By subtracting the energy required to operate the vapor processing equipment necessary to recover the liquid, the net energy impact was determined. For purposes of the calculations, it was assumed that half of the small affected facilities (one quarter of all affected facilities) used thermal oxidation systems and that the remainder used either the carbon adsorption, refrigeration, or compression-refrigeration-absorption system (for Alternative II only).

A net energy savings would result from each of the alternatives evaluated. A net energy savings for each alternative is projected even though it is assumed that as many as half of the small new, modified, or reconstructed terminals may install thermal oxidizer systems, which do not recover energy and have a small negative energy impact. As shown in Table 7-4, Alternative II would accomplish a net fuel savings of 8 million liters (2.1 million gallons) of gasoline per

TABLE 7-4. NATIONWIDE NET ENERGY IMPACTS OF THE REGULATORY ALTERNATIVES[a]

Regulatory Alternative	1985	1990
I	0	0
II	+ 8 million	+14 million
III	+ 6 million	+10 million
IV	+ 9 million	+16 million

[a]Energy unit in net liters of gasoline recovered per year (energy recovered minus energy consumed).

year by 1985. Alternative III would recover a net 6 million liters (1.6 million gallons) of gasoline per year by 1985. Because it results in the greatest recovery of VOC, Alternative IV would result in the greatest net energy savings. Alternative IV would recover a net 9 million liters (2.4 million gallons) of gasoline per year by 1985. By 1990, Alternative IV would result in a net fuel savings of 16 million liters (4.2 million gallons) of gasoline per year.

7.5 OTHER ENVIRONMENTAL IMPACTS

Other potential environmental impacts include noise, space requirements, and availability of resources. The relative impacts of the regulatory alternatives on these environmental concerns is expected to be insignificant. An EPA test showed that the noise level from a CRA unit, which created significantly more noise to the unprotected ear than any other system encountered, was less than 70 db at 7 meters from the noise source.[5] The alternatives cause only minimum impacts due to space requirements and resources availability.

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8.0 ECONOMIC IMPACT

8.1 INDUSTRY CHARACTERIZATION

8.1.1 General Profile

8.1.1.1 Gasoline Distribution System. The gasoline marketing network consists of all the storage and transfer elements which move gasoline from its production stages to its end consumption. The network includes tanker ships and barges, pipelines, tank trucks and railcars, and storage tanks. Almost all of the gasoline consumed in the U.S. is produced in domestic refineries, with less than 3 percent being imported. Crude petroleum is shipped to refineries, which manufacture the wide range of liquid petroleum products. Finished gasoline is then distributed in a complex system comprised of wholesale and retail outlets. Figure 8-1 depicts the main elements in the marketing network.

Gasoline is delivered to bulk terminals from refineries by way of pipeline, tanker, or barge. Large transport trucks (15,000 to 38,000 liter, or 4,000 to 10,000 gallon capacity) deliver the gasoline to service stations or to intermediate bulk storage areas known as bulk stations, or bulk plants. Generally, a terminal is defined as any bulk wholesale gasoline marketing outlet which receives product by pipeline, ship, or barge, and delivers it in tank trucks to customers. A bulk plant typically receives product by truck and has a smaller storage capacity than a terminal. In addition, daily product throughput at a typical terminal is much greater, averaging about 950,000 liters (250,000 gallons), in contrast to about 15,000 liters (4,000 gallons) for a typical bulk plant.

Both bulk terminals and bulk plants deliver gasoline to private, commercial, and retail accounts. Bulk plants, using 5,700 to 11,000 liter (1,500 to 2,900 gallon) capacity delivery trucks, service

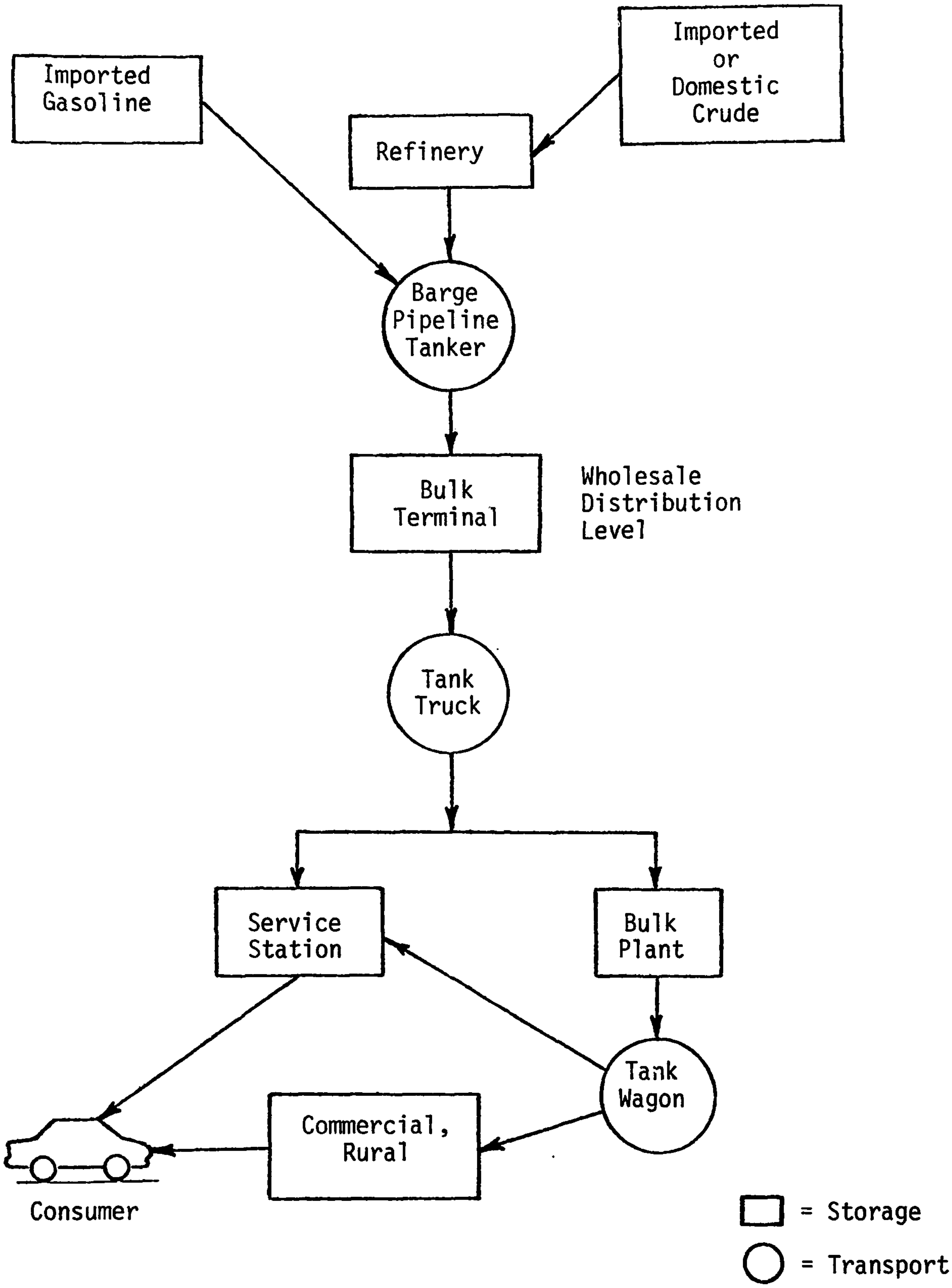

Figure 8-1. Gasoline Distribution in the U.S.

primarily agricultural accounts and service stations that are either long distances from terminals or inaccessible to the large transports. In 1978, approximately 60 percent of gasoline delivered to service stations came from terminals and 40 percent came from bulk plants.[1] The trend in recent years has been toward more terminal deliveries at the expense of bulk plant deliveries. Retail and commercial level businesses include the familiar service stations, as well as commercial accounts such as fleet services (rental car agencies, private companies, governmental agencies), parking garages, and large agricultural accounts. Another important consumer category is about 2.7 million small farms.

8.1.1.2 Bulk Terminal Population. There are presently (1978) an estimated 1,751 bulk terminals in the United States, representing a total storage capacity for petroleum products of 123 million m^3 (771 million barrels).[2] This represents a decline of 9 percent from the 1,925 terminals identified by the Bureau of the Census in 1972. Approximately 45 percent of these terminals receive products from refineries by pipeline, while the remaining 55 percent receive by tanker or barge.[3] An estimated 1,511 bulk terminals, or 86 percent of the total population, store gasoline and have a combined gasoline storage capacity of 47 million m^3 (296 million barrels), or 38 percent of the storage capacity of all bulk terminals.[4] Marine (tanker or barge delivery) terminals store approximately 30 million m^3 (187 million barrels), or 63 percent of the stored gasoline, with the remaining 37 percent handled by pipeline terminals.[5] Terminals not storing gasoline may specialize in distillate, residual, or bunker fuel. Several terminals located in the northern states distribute only home heating oil. Table 8-1 shows the terminal population and storage capacity distribution by Petroleum Administration for Defense District (PADD). Figure 8-2 illustrates the locations of the PADDs.

Most terminals are located in PADDs I and II; i.e., along the east coast and in the Midwest. PADD I contains 43 percent of all bulk terminals and 43 percent of the gasoline terminals. PADD II has 24 percent of all terminals and 23 percent of the gasoline terminals. PADD I received 85 percent of all petroleum products imported into the U.S. in 1978 and 82 percent of all imported gasoline. By contrast,

Table 8-1. 1978 BULK TERMINAL POPULATION[6]

PADD	All Petroleum Terminals					Terminals Storing Gasoline				
	Number of Terminals	Percent of Total	Total Storage Capacity 1,000 m^3	Total Storage Capacity (1,000 Bbl)	Percent of Total	Number of Terminals	Percent of Total	Gasoline Storage Capacity 1,000 m^3	Gasoline Storage Capacity (1,000 Bbl)	Percent of Total
I	745	43	64,166	(403,633)	52	657	43	23,812	(149,792)	51
II	429	24	25,152	(158,219)	21	343	23	9,874	(62,115)	21
III	276	16	20,066	(126,223)	16	234	15	8,227	(51,753)	17
IV	39	2	1,151	(7,238)	1	39	3	674	(4,240)	1
V	262	15	11,987	(75,403)	10	238	16	4,516	(28,408)	10
TOTAL	1,751	100	122,522	(770,716)	100	1,511	100	47,103	(296,308)	100

1,000 m^3 = 10^6 liters

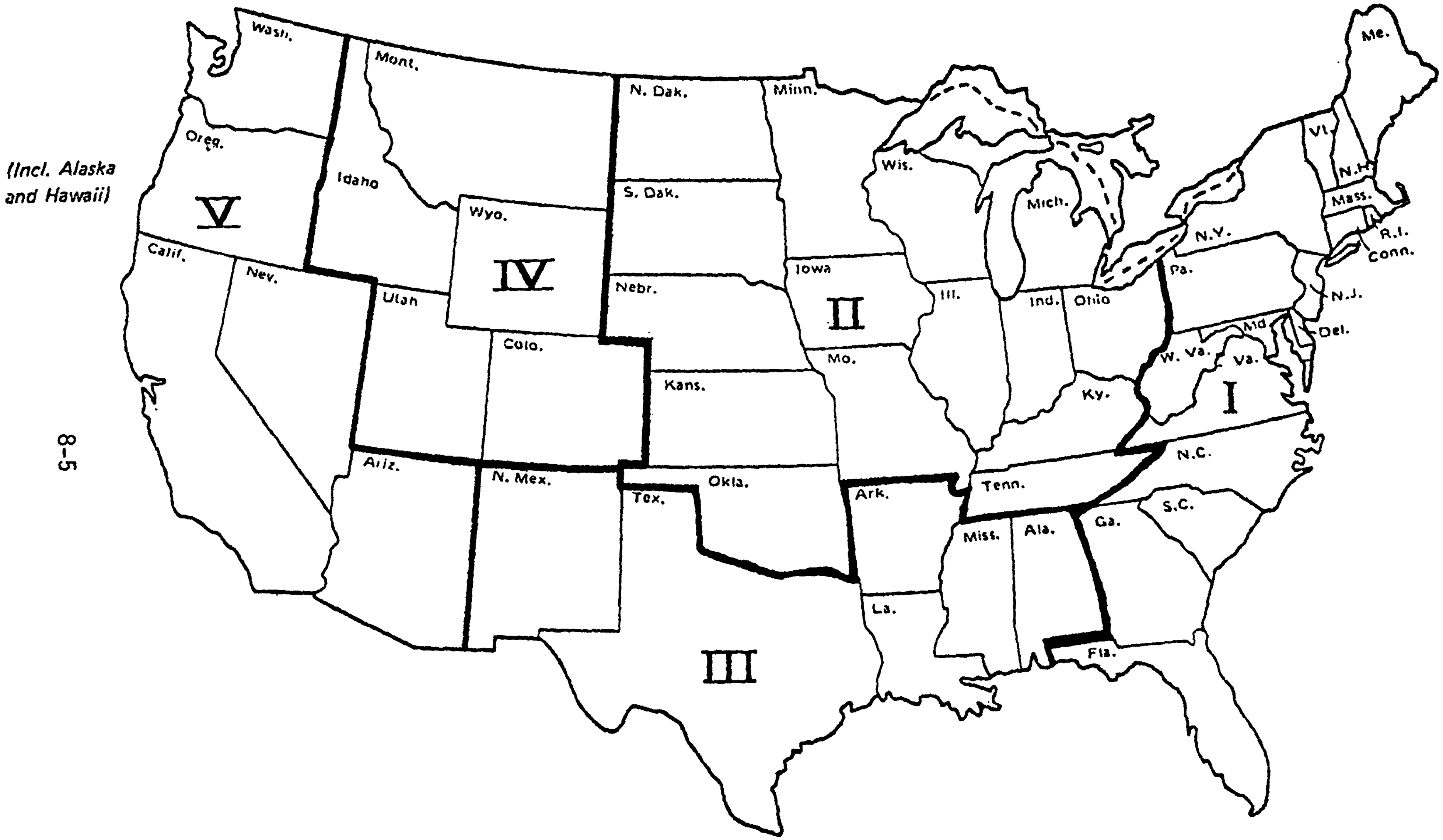

Figure 8-2. Petroleum Administration for Defense Districts

PADD I was responsible for only 12 percent of the total refinery production and for 11 percent of the total gasoline production. Together, PADDs I and II received almost all of the inter-PADD shipments originating in PADD III. Table 8-2 shows the regional total petroleum product supply and demand figures for 1978.

8.1.1.3 Terminal Size. While the total number of terminals in the U.S. has decreased since 1972, total storage capacity increased approximately 30 percent to 123 million m^3 in 1978. This growth in storage capacity has resulted from expansion of large terminals in order to handle increasing product demand, and consolidation or closure of smaller and less efficient facilities.

Due to the large number of terminals in PADDs I and II, they account for most of the total product and gasoline storage. PADD I has 52 percent of all storage and 51 percent of the gasoline storage; PADD II has 21 percent of total and 21 percent of gasoline storage.

The largest segment of the bulk terminal population is composed of smaller facilities. Almost half of all terminals have less than 30,000 m^3 (200,000 barrels) of storage capacity; about 30 percent have capacities between 30,000 and 95,000 m^3; and 22 percent have capacities over 95,000 m^3 (600,000 barrels). For gasoline terminals, the figures are 50 percent less than 30,000 m^3, 28 percent between 30,000 and 95,000 m^3, and 22 percent greater than 95,000 m^3. Table 8-3 shows the distribution of terminals by storage capacity.

Another measure of a bulk terminal's size is its product throughput volume, or the average volume of product delivered over a given time period. The distribution of terminals by total product throughput is fairly even across the selected throughput ranges (Table 8-4). Approximately 36 percent of all terminals have a total product throughput less than 640,000 liters/day, 27 percent have a throughput between 640,000 and 2,540,000 liters/day, and 37 percent have a throughput greater than 2,540,000 liters/day. Almost half of the gasoline terminals, 48 percent, have a gasoline throughput less than 750,000 liters/day, 27 percent have a throughput between 750,000 and 1,510,000 liters/day, and 25 percent have a throughput greater than 1,510,000 liters/day.

Table 8-2. 1978 REGIONAL PRODUCT SUPPLY/DEMAND[7]
1,000 m^3/day (1,000 Bbl/day)

PADD	Demand	Refinery Output	Inter-PADD Shipments: From I	From II	From III	From IV	From V	Imports	Other
I	1,033 (6,498)	289 (1,815)	--	10 (66)	493 (3,100)	--	--	266 (1,671)	10 (66)
II	830 (5,219)	628 (3,950)	35 (220)	--	126 (791)	7 (42)	--	21 (129)	55 (347)
III	627 (3,942)	1,050 (6,602)	--	20 (126)	--	--	0.5 (3)	3 (22)	185 (1,163)
IV	87 (547)	79 (498)	--	11 (68)	--	--	2 (14)	2 (13)	11 (67)
V	417 (2,621)	380 (2,392)	--	--	13 (83)	11 (71)	--	19 (120)	4 (28)
Total	2,994 (18,835)	2,426 (15,257)						311 (1,955)	265 (1,671)

1,000 m^3 = 10^6 liters

Table 8-3. PETROLEUM BULK TERMINAL STORAGE DISTRIBUTION[8]

Total Storage Capacity	All Terminals		Terminals Storing Gasoline	
1,000 m^3 (1,000 Bbl)	Number of Terminals	Percent of Total	Number of Terminals	Percent of Total
<30 (200)	834	48	764	50
30 (200) — 95 (600)	534	30	423	28
95 (600) — 160 (1,000)	215	12	192	13
>160 (1,000)	168	10	132	9
TOTAL	1,751	100	1,511	100

1,000 m^3 = 10^6 liters

Table 8-4. PETROLEUM BULK TERMINAL THROUGHPUT DISTRIBUTION[9]

All Terminals			Terminals Storing Gasoline		
Average Product Throughput 1,000 ℓ/day (1,000 gal/day)	Number of Terminals	Percent of Total	Average Gasoline Throughput 1,000 ℓ/day (1,000 gal/day)	Number of Terminals	Percent of Total
<640 (170)	626	36	<750 (200)	728	48
640 (170) — 2,540 (670)	475	27	750 (200) — 1,510 (400)	401	27
2,540 (670) — 7,000 (1,850)	375	21	1,510 (400) — 2,270 (600)	312	21
>7,000 (1,850)	275	16	>2,270 (600)	70	4
TOTAL	1,751	100	TOTAL	1,511	100

8.1.1.4 Ownership. Major oil companies* own most of the bulk terminals. Their ownership share includes 67 percent of all terminals and 72 percent of the gasoline terminals (Table 8-5). Independents, which includes wholesale/marketers, jobbers** and bulk liquid warehousers,*** own 33 percent of all facilities and 28 percent of those handling gasoline.

The majors own the greatest number of bulk terminals within each gasoline throughput range (Table 8-6). The majors also own a disproportionately greater number of the largest bulk terminals. While the majors own 72 percent of all gasoline terminals, they own 77 percent of the terminals having a storage capacity between 95,000 and 159,000 m^3 and 78 percent of the facilities with greater than 159,000 m^3 of storage capacity, but only 60 percent of the smallest terminals having less than 32,000 m^3. The independents, which own 28 percent of all gasoline bulk terminals, own 42 percent of the smallest terminals, i.e., total storage less than 32,000 m^3, and only 22 percent of the largest facilities; i.e., storage greater than 95,000 m^3.

8.1.1.5 Employment. Bulk terminal employment declined from 40,220 in 1972 to 35,700 in 1978, a decrease of 11 percent. Employment at terminals storing gasoline was estimated to be 30,830, or 86 percent of the total employment, in 1978. PADDs I and II account for 77 percent of the total employment at all terminals and 76 percent of the employment at gasoline terminals. Table 8-7 shows regional employment figures for bulk terminals.

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*Includes regional refiner/marketers. Majors are defined as a fully-integrated company which markets in at least 21 states. A regional refiner/marketer is a semi-integrated company, with at least one refinery, which generally markets in fewer than 21 states.

**A jobber is a petroleum distributor who purchases refined product from a refiner or terminal operator for the purpose of reselling to retail outlets, commercial accounts or reselling through his own retail outlets.

***Bulk liquid warehousers only store products at their facilities for a fee ($/gallon) and do not engage in any marketing activity.

Table 8-5. PETROLEUM BULK TERMINAL OWNERSHIP[10]

Ownership Segment	All Terminals: Number of Terminals	All Terminals: Percent of Total	Terminals Storing Gasoline: Number of Terminals	Terminals Storing Gasoline: Percent of Total
Majors	1,170	67	1,086	72
Independents	581	33	425	28
Total	1,751	100	1,511	100

Table 8-6. GASOLINE TERMINAL DISTRIBUTION BY SIZE AND OWNERSHIP[11]

Total Storage Capacity 1,000 m^3 (1,000 Bbl)	Percent of Total Terminals Storing Gasoline: Majors	Independents	Percent of Total	Total Number of Terminals Storing Gasoline
<30 (200)	30	21	50	764
30 (200) — 95 (600)	25	3	28	423
95 (600) — 160 (1,000)	10	3	13	192
>160 (1,000)	7	2	9	132
TOTAL	72	28	100	
Total Number of Gasoline Terminals	1,086	425		1,511

1,000 m^3 = 10^6 liters

Table 8-7. PETROLEUM BULK TERMINAL EMPLOYMENT[12]

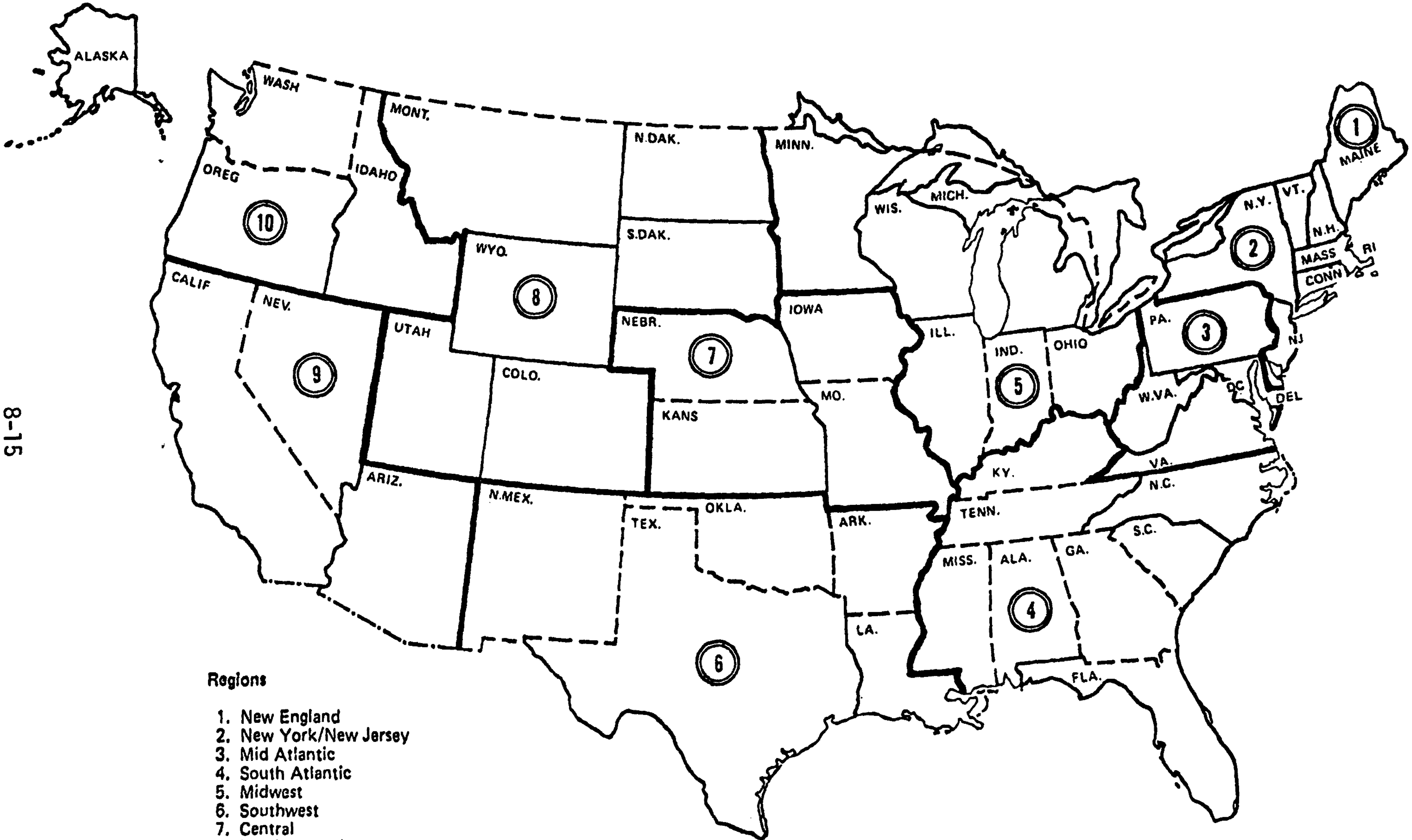
PADD	All Terminals		Terminals Storing Gasoline	
	Employment	Percent of Total	Employment	Percent of Total
I	19,280	55	17,000	56
II	7,850	22	6,280	20
III	4,460	12	3,770	12
IV	440	1	440	1
V	3,670	10	3,340	11
Total	35,700	100	30,830	100

8.1.2 Trends

8.1.2.1 Gasoline Supply and Demand. The demand for the services of gasoline bulk terminals is linked directly to the demand for gasoline in the U.S. economy; i.e., to gasoline consumption. Gasoline consumption is part of a complex equation involving such elements as vehicle population, suburbanization, recreational trends, gasoline costs, and the general state of the economy. Currently these elements are in a state of rapid change.

Gasoline is used almost entirely for motor vehicles, and is by far the most important energy input to transportation, accounting for over 69 percent of the total in 1977.[13] Domestic demand for gasoline, as may be expected, has increased continuously since the end of World War II and the beginning of the "car culture." Consumption went from 410 million liters per day (Ml/day) in 1950, to 650 Ml/day in 1960, to 920 Ml/day in 1970, and reached more than 1,170 Ml/day in 1978.[14,15]

Forecasts of total domestic gasoline demand for the years 1985 and 1990 have been made by the U.S. Department of Energy (DOE).[16] Several scenarios, with different supply, demand, and pricing assumptions, have been analyzed by DOE and tabulated for each of the DOE demand regions shown in Figure 8-3. Three of these DOE projection series were judged as most likely and averaged to obtain forecasts of gasoline demand for the years 1985 and 1990. Table 8-8 lists the three projection series and indicates the major assumptions used in the analysis. Table 8-9 presents the actual gasoline consumption in the U.S. for 1978 and the calculated demand forecasts. These forecasts indicate a gradual decrease in demand in the 1980's, with the projected demand for 1985 being quite close to its 1974 value of 1,030 Ml/day. This similarity is due almost entirely to the assumption of a possible 26 miles per gallon (mpg) standard for the average new automobile by 1985. This would create an average consumption rate for all cars of 19.8 mpg. Another factor influencing the expected decline in the rate of growth of gasoline demand is the shift toward greater usage of diesel engines in cars and small trucks. In the absence of the 26 mpg standard, demand for gasoline in 1985 could be somewhat higher than in 1974. Table 8-10 shows the various components affecting highway gasoline use.



Regions

1. New England
2. New York/New Jersey
3. Mid Atlantic
4. South Atlantic
5. Midwest
6. Southwest
7. Central
8. North Central
9. West
10. Northwest

Figure 8-3. DOE Demand Regions

Table 8-8. DOE PROJECTION SERIES

Series Designation	Supply	Demand	Oil Import Price
B	Low	High	High[a]
C-High	Medium	Medium	High[a]
E	Low	Low	Medium[b]

[a]1985 — \$21.50 per barrel
1990 — \$23.50 per barrel

[b]1985 — \$17.00 per barrel
1990 — \$21.00 per barrel

Table 8-9. REGIONAL GASOLINE CONSUMPTION AND DEMAND FORECASTS
1,000 m^3/day (1,000 Bbl/day)

DOE Demand Region	1978 Gasoline Consumption[15]	Demand Forecast[16] 1985	1990
1	58.2 (366)	49.8 (313)	48.6 (306)
2	101 (634)	81.7 (514)	78.0 (491)
3	120 (755)	102.1 (642)	100.2 (630)
4	218 (1,374)	195.8 (1,232)	199.3 (1,254)
5	251 (1,576)	204.2 (1,285)	197.6 (1,243)
6	156 (982)	133.5 (840)	182.1 (1,145)
7	74.5 (469)	61.5 (387)	59.4 (374)
8	44.1 (277)	36.7 (231)	36.6 (230)
9	143 (901)	123.7 (778)	122.3 (769)
10	47.2 (297)	37.2 (234)	37.2 (234)
TOTAL	1,213 (7,630)	1,026 (6,456)	1,061 (6,676)

1,000 m^3 = 10^6 liters

Table 8-10. COMPONENTS OF HIGHWAY GASOLINE USE[17]

Passenger Cars	1960	1972	1974	1985[a]
Number of Vehicles (Thousands)	62,300	96,900	104,900	131,100
Average Annual Kilometers Driven	15,208	16,383	15,272	18,153
(Miles)	(9,450)	(10,180)	(9,490)	(11,280)
Kilometers Per Liter	6.08	5.74	5.74	8.42
(Miles Per Gallon)	(14.3)	(13.5)	(13.5)	(19.8)
Total Fuel Used — Million m^3	155.9	276.6	279.3	282.8
(Million Barrels)	(981.0)	(1,740)	(1,757)	(1,779)

[a]Projection

Million m^3 = 10^9 liters

Total U.S. demand for petroleum products topped 3.34 million m^3/day (21.0 million barrels/day) in the early part of 1979. By August 1979, this figure had dropped nearly 14 percent to 2.88 million m^3/day (18.1 million barrels/day). At the same time, total refinery capacity stood at 2.81 million m^3/day (17.7 million barrels/day), with an operating ratio of 86.5 percent.[18] These figures indicate a disparity between petroleum product demand and actual domestic production. Refiners have expressed hesitation concerning expansion of their facilities because of the expected stabilization in gasoline demand in the 1980's. In addition, environmental costs and the uncertain economic outlook have been cited as reasons to forego expansion and new construction plans.

Petroleum imports declined 6 percent from 1978 to early 1979, and this trend could continue as OPEC and other countries continue restrictive export and pricing policies. The increase in petroleum product consumption during the same period was met by inventory drawdowns and by higher North Slope (Alaska) production.

The demand for gasoline in the U.S. has been historically relatively unresponsive to price. In 1973, with the average regular leaded gasoline retail price at 10.2¢/liter (38.8¢/gallon), the average passenger car was driven about 10,000 miles per year. At the current average price of 22.9¢/liter (86.9¢/gallon) (June 1979), there is indication that cars are driven about the same total mileage. If general price inflation in the economy continues at a high rate, the decontrol of gasoline prices expected to be effective by 1981,[19] as well as price increases due to other factors, are likely to have an increasingly greater effect in the direction of lessening demand.

Gasoline domestic production for 1978, as well as supply forecasts for 1985 and 1990, are presented in Table 8-11. The forecast figures are averages for the three DOE projection series shown in Table 8-8. These data indicate a gradual decrease in domestic production of approximately 2 percent over the coming decade. Gasoline imports are expected to increase dramatically in the early 1980's, and then level off by the end of the decade.

Table 8-11. REGIONAL GASOLINE PRODUCTION AND SUPPLY FORECASTS
1,000 m^3/day (1,000 Bbl/day)

PADD	1978 Gasoline Production[20]	Supply Forecast (Domestic Refineries)[16]	
		1985	1990
I	117 (733)	109 (689)	131 (822)
II	312 (1,962)	322 (2,024)	312 (1,960)
III	402 (2,529)	386 (2,427)	364 (2,288)
IV	35.0 (220)	36.8 (231)	36.6 (231)
V	157 (989)	161 (1,012)	160 (1,003)
Total Domestic Supply	1,023 (6,433)	1,015 (6,383)	1,004 (6,304)
Imports	31.2 (196)	72.6 (457)	73.0 (459)

1,000 m^3 = 10^6 liters

8.1.2.2 Terminal Recent Trends. Beginning about 1970, oil companies began to view their refining and marketing operations as separate profit centers to be judged on "stand alone" economics. Terminals are now expected to recover all operating expenses as well as to provide an acceptable return on capital. The former practice of subsidizing market activities by means of other operations gave way to this new economic outlook. This trend was accelerated by the Oil Embargo of 1973-74.

"Stand alone" economics has caused petroleum marketers, both majors and independents, to review their marketing strengths and reconsider their overall distribution strategies. As a result, many uneconomical storage facilities have been closed or consolidated into larger and more profitable facilities. When several terminals compete for business within the same area of distribution, the largest, and presumably most efficient installations have a competitive edge over their smaller neighbors. In addition, terminals receiving product by pipeline gain an advantage by eliminating the costs associated with barge or tanker docking and unloading facilities.

The terminal population decreased by 9 percent from 1972 to 1978 (Section 8.1.1.2). The primary reasons are based on profitability considerations, or "stand alone" economics. At the same time, total storage capacity has increased by 30 percent during the same time period, due to consolidation and expansion of existing terminals. Employment at bulk terminals declined 11 percent, as the efficiency of terminals was increased by expansion and the installation of modernized equipment.

Loading racks have been converted at many facilities from top loading to bottom loading. Accompanying this change, vapor recovery systems have been installed or modernized. This trend is continuing as states revise their VOC emission regulations.

8.1.2.3 Terminal Future Trends. Future trends in the bulk terminal industry are toward further consolidation of existing facilities, as economic considerations continue to dictate the necessity of increasing efficiency. The relatively small number of new terminals and new distribution markets expected to open up in the next 10 years is in keeping with the gasoline demand projections cited earlier. The estimated number of new facilities, as well as the number which will be affected due to modification or reconstruction, for the years 1982, 1985, and 1990 are presented in Table 8-12. The expected sizes of these terminals are expressed in terms of the daily gasoline throughputs used to define the model plants. These estimates are based primarily on information obtained from oil companies through Section 114 letter requests. Examples of modifications and reconstructions to terminals which will make them subject to affected facility determination are discussed in Section 5.2 of Chapter 5. Some of the new terminals will be erected to replace existing facilities or groups of facilities. The only DOE demand region showing a projected demand increase between 1978 and 1990 (16.7 percent) is Region No. 6 (Southwest), so new facilities are likely to be erected in that Region. The smallest decrease in demand (8.6 percent) is projected for Region No. 4 (South Atlantic).

8.1.3 Tank Truck Industry

8.1.3.1 Industry Structure. The trucking industry generally consists of two major groups, for-hire and private. Private carriers are firms which transport their own goods in their own trucks. Examples of private carriers are the oil companies which utilize their own tank trucks to deliver gasoline from their terminals. For-hire carriers transport freight which belongs to others, renting out the hauling services of their trucks.

8.1.3.2 Vehicle Population. The tank vehicles used for transporting gasoline from bulk terminals are classified into three types: straight truck, semi-trailer, and full trailer. It is estimated that of the 100,000 tank vehicles in flammable liquid service, 85,000 are used for the delivery of gasoline.[21] About 31 percent of the gasoline tank vehicles, or 26,300 vehicles, are used at bulk terminals. Of these, approximately 2,630 are straight trucks and 23,670 are one of the trailer types.[22] The remainder are smaller tank trucks used primarily to transport gasoline from bulk plants. All types of tank vehicles are referred to as tank trucks throughout the balance of this document.

Due to differences in construction, gasoline tank trucks can be divided into three age categories. The establishment of motor carrier regulations in 1967 by the Department of Transportation[23] made retrofit

Table 8-12. ESTIMATED NUMBER OF AFFECTED TERMINAL FACILITIES IN VARIOUS YEARS[a]

Year	Facility Category	GASOLINE THROUGHPUT (ℓ/day)				Total
		380,000	950,000	1,900,000	3,800,000	
1982	New	0	1	1	0	2
	Modified/ Reconstructed	10	5	5	0	20
1985	New	0	2	2	1	5
	Modified/ Reconstructed	25	13	12	0	50
1990	New	0	3	4	3	10
	Modified/ Reconstructed	50	25	25	0	100

[a]Totals represent cumulative number of affected facilities through the years indicated.

of newer tank trucks to a bottom loading or vapor recovery configuration more practicable. The cost of retrofitting the older vehicles is higher than the cost for newer vehicles, because provisions for conversion have been incorporated in vehicles of recent construction. An estimated breakdown of vehicles by date of construction is presented in Table 8-13. Table 8-14 shows trends of tank truck age distribution by PADD as measured by the census surveys of 1972 and 1977. This table demonstrates the expected decrease in the number of older vehicles over this time period. Since the average vehicle lifespan is about 13 years for tank trailers, and 8 years for straight trucks,[24] the number of pre-1967 vehicles is expected to be negligible by 1985.

Since tank trucks in non-attainment areas will already be bottom loaded and contain vapor recovery provisions in order to comply with SIP regulations, only those tank trucks operating in attainment areas would be affected by the regulatory alternatives. It is conservatively estimated that 7,360, or 28 percent, of the 26,300 tank trucks at bulk terminals would be affected. This assumes that none of the gasoline tank trucks at terminals in attainment areas would already contain bottom loading and vapor recovery provisions, and that SIP regulations would not apply in any attainment areas. While neither assumption is entirely true, they are considered sufficiently accurate approximations. Their effect is to magnify slightly the cost impact of converting tank trucks.

There are approximately 423 bulk gasoline terminals (28 percent of the 1,511 total) in attainment areas. It is estimated that there will be 32 affected facilities (30 existing, 2 new) in attainment areas by 1985. Therefore, 7.6 percent of the terminals in attainment areas would come under the new regulations and the tank trucks operating at these terminals would require retrofitting. The total number of tank trucks thus affected would be about 7.6 percent of 7,360, or 558 tank trucks. Based on the number of terminal-operated tank trucks assumed for the bulk terminal model plants (Table 6-2 of Chapter 6), approximately 390 of the affected tank trucks would be operated by for-hire tank truck firms. Table 8-15 shows the estimated number of affected tank truck firms and tank truck conversions for each model

Table 8-13. ESTIMATED AGE DISTRIBUTION OF GASOLINE TANK TRUCKS AT BULK TERMINALS

Age	Straight Trucks	Trailers	Total
1976-1978	500	4,000	4,500
1967-1975	1,870	17,830	19,700
Pre-1967	260	1,840	2,100
Total	2,630	23,670	26,300

Table 8-14. REGIONAL TRENDS IN GASOLINE DELIVERY TANK[a] DISTRIBUTION BY YEAR OF MANUFACTURE[22,25]

(Percent of Total)

PADD	Pre-1967		1967-1972		1973-75	1976-78	Overall Distribution	
	1972 Census[b]	1977 Census[c]	1972 Census[b]	1977 Census[c]	1977 Census[c]	1977 Census[c]	1972 Census[b]	1977 Census[c]
I	14.0	3.4	28.2	16.4	16.7	7.4	42.3	43.9
II	8.4	0.6	19.2	9.8	7.4	3.1	27.6	20.9
III	3.7	1.1	8.5	6.1	7.9	3.7	12.2	18.8
IV	4.0	1.4	5.2	1.9	1.6	1.1	9.2	6.1
V	4.0	2.7	4.7	3.4	2.9	1.3	8.7	10.3
Totals[d]	34.2	9.3	65.8	37.6	36.5	16.6	100.0	100.0

[a]Includes straight truck and trailer delivery tanks of greater than 15,000 liter (4,000 gallon) capacity.

[b]Sample size = 1,161.

[c]Sample size = 622.

[d]Sum of regional percentages not always equal to totals due to rounding.

Table 8-15. ESTIMATED NUMBER OF AFFECTED TANK TRUCK COMPANIES AND TANK TRUCKS IN VARIOUS YEARS[a]

YEAR	CATEGORY	MODEL FIRM				TOTAL
		1	2	3	4	
1982	Companies	6	3	3	2	14
	Tank Trucks	10	20	40	80	150
1985	Companies	16	7	7	4	34
	Tank Trucks	35	50	105	200	390
1990	Companies	32	14	14	8	68
	Tank Trucks	70	100	210	400	780

[a]Totals represent cumulative number of affected companies and tank truck conversions to bottom loading and/or vapor recovery through the years indicated.

firm developed in Section 6.2.5 of Chapter 6. Section 8.2.3.1 discusses tank truck conversion costs. The cost analysis for the for-hire tank truck industry is contained in Section 8.2.5, and the economic impact on this industry is assessed in Section 8.4.2.

8.1.3.3 Loading Methods and Vapor Recovery. A survey report to EPA[21] indicates that approximately 77.2 percent of tank trucks have bottom loading capability, and 22.8 percent can only be top loaded (see Section 3.2.2.3). The survey further reports that 70 percent of those tanks for which data were available contain vapor collection equipment. This percentage drops to 52 percent if it is conservatively assumed that tanks for which data were not provided do not have vapor recovery capability. This limited survey was based upon data on approximately 1,900 tank trucks. Table 8-16 shows the percentage of tanks with bottom loading and vapor recovery as a function of company size.

8.2 COST ANALYSIS OF REGULATORY ALTERNATIVES

8.2.1 Introduction

Capital expenditures and annualized costs for the control of VOC emissions from bulk gasoline terminal loading operations have been estimated for 140 control options (combinations of facility classification, regulatory alternative, model plant size, and vapor control unit type). Costs for new facilities are presented in Section 8.2.2.1, and costs for existing facilities which undergo modification or reconstruction are presented in Section 8.2.3.1. Five classifications of affected facilities have been analyzed and are representative of all the situations expected to be encountered under the new standard.

Cost tables are provided for the four model plant sizes with gasoline throughputs of 380,000, 950,000, 1,900,000, and 3,800,000 liters per day (100,000, 250,000, 500,000, and 1,000,000 gallons per day, respectively). The complete list of model plant parameters is presented in Table 6-2; Section 6.2 of Chapter 6 explains in detail the basis for the choice of model plant parameters. Costs have been developed for Regulatory Alternatives II, III, and IV in areas where the SIP emission control regulations are not in effect, since these

Table 8-16. TANKS WITH BOTTOM LOADING AND VAPOR RECOVERY AS A FUNCTION OF COMPANY SIZE[25]

Number of Tanks in Company	Total Tanks	Bottom Loading			Vapor Recovery		
		With	Without	Percent With	With	Without	Percent With
1-4	43	27	15	64	19	18	51
5-10	79	57	22	72	69	5	93
11-49	316	208	90	70	177	135	57
≥ 50	1,501	1,182	319	79	746	278	73
Total	1,939	1,474	446	77	1,011	436	70
Total Tank Basis[a]				76			52

[a]Percentages assuming that tanks for which data were not available do not have bottom loading or vapor recovery capabilities.

situations would involve differential costs for an affected facility. In addition, differential costs could accrue to a terminal in a non-attainment area, which underwent modification or reconstruction. Under Alternatives III and IV, which require an emission limit of 35 mg/liter, an existing vapor control unit that was capable of achieving only the SIP control level of 80 mg/liter may have to be replaced with a more efficient unit or supplemented with a secondary, or "add-on" unit. For this analysis, the cases where a compression-refrigeration-absorption (CRA) type control unit has been replaced with a carbon adsorption (CA), thermal oxidizer (TO), or refrigeration (REF) type unit, or has been supplemented with a CA or TO unit, have been examined. The regulatory alternatives are presented in Table 6-4 and explained in Section 6.3 of Chapter 6.

In developing costs for controlling VOC emissions at terminals, specific cost information was obtained through plant visits, Section 114 letter responses, and telephone contacts with terminal operators, equipment manufacturers, and contractors. Also, existing EPA and other background information and reports were consulted. All costs are provided in terms of mid-1979 dollars, having been adjusted for inflationary effects, where appropriate. Costs were adjusted to a common base by applying the June 1979 Chemical Engineering Plant Cost Index.[27]

Most of the cost information received applies to existing facilities and control installations. As discussed in Section 7.1, most affected facilities (as defined in Chapter 5 and developed in Chapter 6) will be so designated as a result of modification or reconstruction of existing facilities, instead of the construction of new facilities.

Capital investment includes the purchase price of the vapor control unit, the cost of installing the system, and the cost of converting tank trucks or loading racks, as appropriate, to a vapor recovery configuration. The costs involved in converting tank trucks and racks from top loading to bottom loading are also included, because there is no existing top loading vapor recovery system considered capable of achieving the level of control required under the regulatory alternatives. Also, a salvage cost credit is applied for the case where an existing control unit is replaced with a more efficient unit.

Annualized costs include the amortization of capital investment and the incremental operating expenses associated with vapor control. Additional items in the tables include gasoline recovery cost credits, total yearly VOC controlled, and cost-effectiveness of each option (in dollars expended per kilogram of VOC controlled). The costs involved with complying with the regulations (performance testing and continuous monitoring) are presented in Section 8.2.2.7.

8.2.2 New Facilities

8.2.2.1 Capital Investment. New facility differential costs incurred in complying with the regulatory alternatives depend on whether SIP regulations are already applicable to that facility. New facilities constructed in previously regulated (generally non-attainment) areas will undergo no additional costs as a result of any of the regulatory alternatives. This is because the CA, TO, and REF systems being installed to meet 80 mg/liter are essentially identical to those systems which would be considered for a 35 mg/liter limit. Cost estimates for new facilities in previously unregulated (attainment) areas are presented in Tables 8-17 through 8-19. Notes for these tables are contained on page 8-35. The following subsections describe in detail the development of the capital investment costs.

8.2.2.1.1 Control equipment purchase cost. Equipment manufacturers were contacted to obtain price quotations on vapor control units for application at each of the model plants. The purchase costs of CA and CRA type units represent information provided by a single source for each type of unit, because only one manufacturer is known to be actively marketing each of these types at this time.[28,29] Costs of the TO and REF type units represent the average of price quotations provided by several makers of the units.[30,31,32,33,34] The cost of a suitable vapor holder is included in the CRA unit cost because this device is always included in a CRA system installation.[29] Since the vapor holder is only occasionally used with the other types of units, its cost is not included for those systems. The CRA unit is not costed under Regulatory Alternatives III and IV because test data indicate that the 35 milligrams per liter emission limit cannot be achieved by this unit. All equipment costs include the complete unit with all

Table 8-17. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE II
(Thousands of Mid-1979 Dollars)
NEW FACILITY IN ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day				950,000 ℓ/day				1,900,000 ℓ/day				3,800,000 ℓ/day			
Vapor Processing Unit:	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]
Capital Investment																
Unit Purchase Cost	160	140	90.0	143	185	140	100	170	185	172	100	175	225	200	115	220
Unit Installation Cost	136	119	76.5	122	157	119	85.0	145	157	146	85.0	149	191	170	97.8	187
Truck Vapor Recovery Cost[e]	6.0	6.0	6.0	6.0	12.0	12.0	12.0	12.0	18.0	18.0	18.0	18.0	40.0	40.0	40.0	40.0
Annual Operating Cost																
Electricity[f]	6.6	1.5	1.5	14.7	9.9	3.8	3.7	20.3	13.3	7.5	6.9	22.8	16.8	15.7	12.9	32.6
Propane (Pilot)[g]	--	--	2.0	--	--	--	3.6	--	--	--	6.6	--	--	--	8.7	--
Maintenance	7.0	11.8	4.2	12.0	8.2	12.0	4.8	14.4	8.2	14.6	4.8	14.8	10.0	17.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	--	1.5	--	--	--	1.5	--	--	--	1.8	--	--	--
Subtotal (Direct Operating Cost)	18.0	16.7	11.1	30.1	23.0	19.2	15.5	38.1	26.4	25.5	21.7	41.0	32.0	36.1	30.6	54.6
Truck Maintenance[j]	0.5	0.5	0.5	0.5	0.9	0.9	0.9	0.9	1.4	1.4	1.4	1.4	3.0	3.0	3.0	3.0
Capital Charges	60.4	53.0	34.5	54.2	70.8	54.2	39.4	65.4	72.0	67.2	40.6	68.4	91.2	82.0	50.6	89.4
Gasoline Recovery (Credit)	25.5	25.5	--	25.5	63.8	63.8	--	63.8	128	128	--	128	255	255	--	255
Net Annualized Cost	53.4	44.7	46.1	59.3	30.9	10.5	55.8	40.6	-28.2	-33.9	63.7	-17.2	-129	-134	84.2	-108
Total VOC Controlled (Mg/yr)	101	101	101	101	252	252	252	252	505	505	505	505	1,010	1,010	1,010	1,010
Cost Effectiveness ($/kg)	0.53	0.44	0.46	0.59	0.12	0.04	0.22	0.16	(k)	(k)	0.13	(k)	(k)	(k)	0.08	(k)

Table 8-18. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE III (Thousands of Mid-1979 Dollars) NEW FACILITY IN ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	136	76.5	122	157	85.0	145	157	85.0	149	191	97.8	187
Truck Vapor Recovery Cost[e]	6.0	6.0	6 0	12.0	12.0	12.0	18.0	18.0	18.0	40.0	40.0	40.0
Annual Operating Costs												
Electricity[f]	6.6	1.5	14.7	9.9	3.7	20.3	13.3	6.9	22.8	16.8	12.9	32.6
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	7.0	4.2	12.0	8.2	4.8	14.4	8.2	4.8	14.8	10.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	18.0	11.1	30.1	23.0	15.5	38.1	26.4	21.7	41.0	32.0	30.6	54.6
Truck Maintenance[j]	--	--	--	--	--	--	--	--	--	--	--	--
Capital Charges	60.4	34.5	54.2	70.8	39.4	65.4	72.0	40.6	68.4	91.2	50.6	89.4
Gasoline Recovery (Credit)	20.7	--	20.7	51.8	--	51.8	104	--	104	207	--	207
Net Annualized Cost	57.7	45.6	63.6	42.0	54.9	51.7	-5.6	62.3	5.4	-83.8	81.2	-63.0
Total VOC Controlled (Mg/yr)	82	82	82	205	205	205	410	410	410	820	820	820
Cost Effectiveness ($/kg)	0.70	0.56	0.78	0.20	0.27	0.25	(k)	0.15	0.01	(k)	0.10	(k)

Table 8-19. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE IV
(Thousands of Mid-1979 Dollars)
NEW FACILITY IN ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	136	76.5	122	157	95.0	145	157	85.0	149	191	97.8	187
Truck Vapor Recovery Cost[e]	6.0	6.0	6.0	12.0	12.0	12.0	18.0	18.0	18.0	40.0	40.0	40.0
Annual Operating Costs												
Electricity[f]	6.6	1.5	14.7	9.9	3.7	20.3	13.3	6.9	22.3	16.8	12.9	32.6
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	7.0	4.2	12.0	8.2	4.8	14.4	8.2	4.8	14.8	10.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	18.0	11.1	30.1	23.0	15.5	38.1	26.4	21.7	41.0	32.0	30.6	54.6
Truck Maintenance[j]	0.5	0.5	0.5	0.9	0.9	0.9	1.4	1.4	1.4	3.0	3.0	3.0
Capital Charges	60.4	34.5	54.2	70.8	39.4	65.4	72.0	40.6	68.4	91.2	50.6	89.4
Gasoline Recovery (Credit)	27.0	--	27.0	67.4	--	67.4	135	--	135	270	--	270
Net Annualized Cost	51.9	46.1	57.8	27.3	55.8	37.0	-35.2	63.7	-38.0	-172	84.2	-151
Total VOC Controlled (Mg/yr)	107	107	107	267	267	267	535	535	535	1,070	1,070	1,070
Cost Effectiveness ($/kg)	0.49	0.43	0.54	0.10	0.21	0.4	(k)	0.12	(k)	(k)	0.08	(k)

NOTES FOR TABLES 8-17 THROUGH 8-19

[a]CA = Carbon Adsorption Unit.

[b]CRA = Compression-Refrigeration-Absorption Unit.

[c]TO = Thermal Oxidizer Unit.

[d]REF = Refrigeration Unit.

[e]Additional cost required for vapor collection equipment on new tank tank trucks.

[f]Electricity costs are based on average consumption rates reported by manufacturers.

[g]Propane for pilot estimated at 12.5 liters per hour based on manufacturers' reported consumption.

[h]Daily inspections at one hour per day, plus a monthly visual inspection for liquid or vapor leaks in the vapor collection and processing systems.

[i]Estimated carbon replacement period is 10 years.

[j]Cost to perform annual vapor-tight testing.
Average number of terminal-owned trucks:

380,000	liters/day	3
950,000	liters/day	6
1,900,000	liters/day	9
3,800,000	liters/day	20

[k]Cost-effectiveness not calculated because net annualized cost is a negative quantity (cost credit).

controls, and generally a start-up service. Some REF units contain a meter to monitor recovered product, and some TO units include vapor stream saturators and aftercoolers in the system cost. Equipment costs can be considered to represent the average cost for each type of control system. Generally, piping runs, condensate tanks, and all installation and service charges, including taxes, are separate expenses and are included under installation costs. Figure 8-4 shows the equipment purchase costs used in the cost tables. The exact figures are shown in Tables 8-17 through 8-19. It should be noted that in increasing the throughput by a factor of ten (from model plant 1 to model plant 4), the average increase in the equipment purchase cost is only about 42 percent.

8.2.2.1.2. Control equipment installation cost. The costs involved in engineering, shipping, and installing a vapor control system account for a major percentage of the total system cost. Most of the information concerning these costs was obtained through Section 114 letter responses. Due to the varying requirements of individual terminals, the costs of installing control systems at different terminals cover a wide range. Only cost information for which a breakdown by cost element was available was used for determining the relative contribution of each element to the total installation cost. The elements common to most installations include engineering approvals, site preparation and concrete pad, piping, electrical service, condensate tank, and a final category which includes optional or variable equipment plus taxes, freight, and contingencies. Best estimates of the contribution of each of these cost elements are presented in Table 8-20. The range of values occurring in the data received from terminal operators is also shown.

Just as the individual cost elements can vary widely, so also does the total installation cost vary in actual installations. An examination of the data received from terminal operators indicates that the installation cost can be estimated as 85 percent of the equipment purchase cost. The data used in this calculation represent installation of CA, CRA, TO, and REF control units at terminals ranging in size from 380,000 liters per day to 3,800,000 liters per day. While these data represent the installation of new control units at

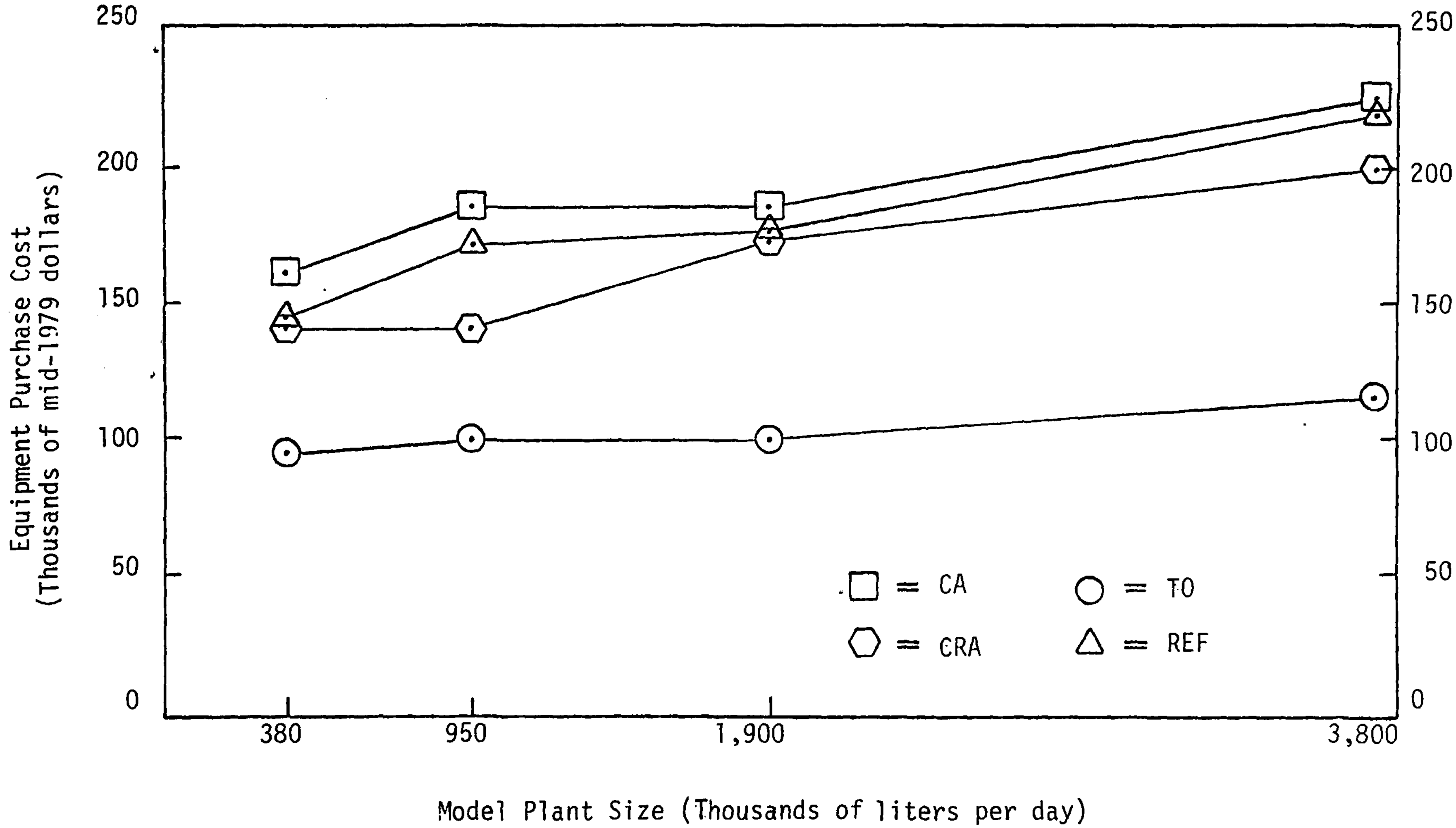


Figure 8-4. Control Equipment Purchase Costs
(Thousands of mid-1979 Dollars)

Table 8-20. INSTALLATION COST ELEMENTS

Cost Element	Best Estimate Contribution to Total Installation (Percent)	Range in Actual Installations (Percent)
Engineering and approvals	20	17 to 28
Concrete Pad	15	5 to 30
Piping	15	3 to 39
Electrical Service	15	8 to 27
Condensate Tank	10	1 to 25
Other:		
Flame Arresters and Check Valves	5	a
Setting Unit	5	a
Freight	3	a
Taxes	4	a
Contingency Fund	8	a
TOTAL	100	

[a]Data range not available.

existing terminals, it is assumed that the same cost elements also represent installation costs at new terminals. Figure 8-5 illustrates 14 control system installations at terminals. These data do not include the additional cost of purchasing new tank trucks with vapor recovery provisions. This cost is discussed in the next subsection.

8.2.2.1.3 Tank truck vapor recovery. It is assumed that all new terminals will purchase new, bottom loading tank trucks. Under Regulatory Alternatives II, III, and IV these trucks will require vapor recovery provisions. The added cost for a new tank truck with vapor recovery provisions over one without these provisions is estimated from several sources to be $400 per compartment, or $1,600 per four-compartment truck.[35,36] The additional equipment on a converted truck consists of vapor collection hoods, P-V vents, and vapor collection lines for each compartment, as well as an adapter for connection to a vapor return line at the loading rack.

8.2.2.2 Annualized Costs. The annualized cost of a vapor control installation is the total annual expenditure required to operate and maintain the installation and is the sum of operating costs and capital charges. Operating costs are the day-to-day expenses required to keep the system in operation and include utilities, raw materials, maintenance and repairs, and routine operating labor (such as daily inspections). Another component of the operating cost is the cost of the annual tank truck vapor-tight test (Regulatory Alternatives II and IV). Capital charges include depreciation, taxes, insurance, and interest on borrowed capital. Table 8-21 summarizes the cost factors used to produce the annualized costs. Table 8-22 presents the calculation methods used in determining the annualized costs.

All of the control units considered in this analysis consume electric power in the course of their operation. Electricity is used to power fans, dampers, pumps, compressors, relays, and timers. The electrical consumption rate of each type of unit during operation was obtained from control unit manufacturers. The actual hours-per-day operating schedules of the units were determined from likely average terminal loading schedules and from a limited amount of actual operating data. Some CA units remain in operation for up to two hours

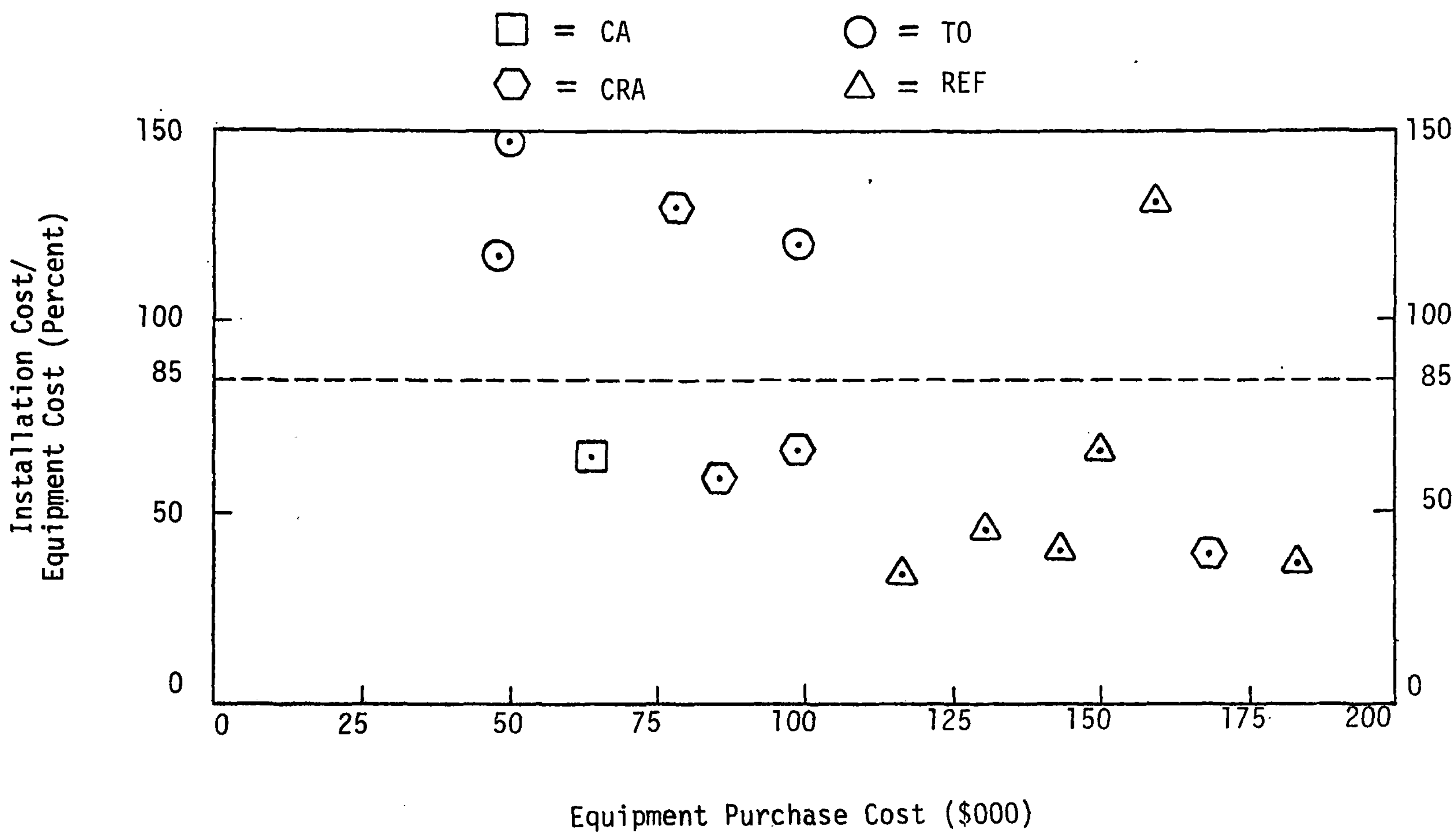


Figure 8-5. Control Equipment Installation Costs as a Function of Purchase Cost

Table 8-21. COST FACTORS USED IN DEVELOPING ANNUALIZED COSTS

Utilities and Materials	
Electricity	\$0.06/kw-hr
Propane	\$0.12/liter
Replacement Carbon	\$3.30/kg
Operating Labor	\$10/labor hour
Maintenance (Percent of Equipment Cost)	
Refrigeration	8 percent
CRA Vapor Recovery	8 percent
CA Vapor Recovery	4 percent
Thermal Oxidizer	4 percent
Capital Charges (Percent of Total Capital Cost)	
Interest and Depreciation	16 percent
Property Taxes, Insurance, and Administration	4 percent
Recovered Gasoline Value	\$0.17/liter

Table 8-22. CALCULATION OF ANNUALIZED COSTS OF VAPOR CONTROL UNITS

Cost Component	Method of Calculation
Direct Operating Costs	
Utilities and Materials	
Electricity	Amount used per year x \$0.06/kw-hr
Propane (pilot)	Amount used per year x \$0.12/liter
Activated Carbon	Amount replaced x \$3.30/kg ÷ 10 yrs
Operating Labor	1 hr/day x 340 days/yr x \$10.00/ labor hour
Maintenance	
CA and TO Units	4 percent of equipment purchase cost
CRA and REF Units	8 percent of equipment purchase cost
Capital Charges	Capital investment x (capital recovery factor + 0.04)[a]
Gasoline Recovery (Credit)	Amount recovered per year x \$0.17/ liter

[a]Capital recovery factor = $\frac{i\,(1 + i)^n}{(1 + i)^n - 1}$

where i = interest rate = 0.10 (10 percent)

n = equipment economic life = 10 years

after loading activity ceases, so they are likely to be in operation the majority of the time at most terminals. The TO unit operates only during actual loading activity. This time schedule was conservatively estimated, based on the model plant parameters. For example, the smallest model plant may operate up to

$$\frac{380{,}000 \text{ liters/day}}{(32{,}200 \text{ liters/truck})\ (3 \text{ trucks/hr})} = 4 \text{ hrs/day.}$$

The REF unit operates on demand in order to maintain a low heat exchanger temperature, and thus activates even when no loading is in progress. This time period was estimated to be 12 hours per day for all model plants. A value of $0.06 per kilowatt-hour was used, based on values reported to EPA. Table 8-23 summarizes the operating parameters used to calculate annual electrical costs.

Thermal oxidizer units require a pilot fuel source, generally propane, with some units using natural gas or No. 2 fuel oil. Information from manufacturers indicates that an average of 12.5 liters (3.3 gallons) per hour of propane are consumed by TO units during their operation.[34,38] The propane wholesale cost, in mid-1979 dollars, is approximately $0.12 per liter in transport load (34,600 liters) quantities.

The working life of the activated carbon used in CA units has not been determined. It is assumed in this analysis that an accumulated "heel" will develop in the carbon beds and require that the carbon be removed for recycling or disposal. One manufacturer has conducted rapid cycle tests and has concluded the useful carbon life will be 20 years. However, since CA units have been operating commercially at bulk terminals only since 1976, a conservative estimate of 10 years carbon useful life has been used in preparing the cost analysis. Carbon weights in each unit were supplied by the same manufacturer, as was the price of $3.30 per kilogram for activated carbon.[28,41]

Operating labor for a vapor control unit consists of the labor required to perform routine daily inspections of the unit, including checking meter readings, fluid levels, and the proper operation of system components and making necessary adjustments or minor repairs.

Table 8-23. ELECTRICAL CONSUMPTION AND OPERATING SCHEDULES OF VAPOR CONTROL UNITS

Model Plant	Operating Kilowatts[a]				Operating Schedule (Hr/day)[b]				Energy Consumption (kw-hr/day)[c]			
	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
1	23.2	---	18.6	60	14	---	4	12	325	74	74	720
2	32.5	---	26.0	83	15	---	7	12	487	185	182	996
3	32.5	---	26.0	93	20	---	13	12	650	370	338	1,116
4	37.4	---	37.2	133	22	---	17	12	823	770	632	1,596

[a]CA unit: Data provided by single manufacturer.[28]
CRA unit: Data provided as kw-hr/day.[37]
TO and REF units: Average from several manufacturers.[30,31,33,34]

[b]CA unit: Data from actual operating experience and engineering judgment.
CRA unit: Data provided as kw-hr/day.[37]
TO unit: Based on engineering judgment.
REF unit: Data from single manufacturer and engineering judgment.[40]

[c]CRA unit: Data provided by single manufacturer.[37]

Information obtained from terminal operators on plant visits indicates that a routine checklist can be followed in 30-45 minutes, so an estimate of one hour per day was used. Labor charges were provided from the same sources as $10.00 per hour. Also included in this cost is a monthly visual inspection of the vapor collection and processing systems for liquid or vapor leaks.

Annual maintenance costs include major adjustment, repair, and replacement items not covered in the category of operating labor. Maintenance items include pump seal and compressor replacement, replenishment of fluids, and burner, valve, relay, and timer replacement. Some terminals contract an outside firm to perform all major maintenance on a periodic or as-needed basis, while others perform essentially all maintenance work in-house. Maintenance contracts on refrigeration units have been reported to cost about $4,000 per year, labor only, or $7,000 to $10,000, including labor and parts.[31,42] Costs depend on whether a control unit is within the service area of the contractor. Information from Section 114 letter responses indicates that maintenance costs for the REF unit average about 8 percent of the equipment purchase cost. Costs for the CRA type units are assumed to also average 8 percent. Maintenance on the CA and TO type units have been found to be lower, averaging about 4 percent of equipment cost. These figures are variable, depending on the equipment manufacturer, age, and quality of routine care. Other items affecting these figures can include the level of activity of the terminal (unit operating time) and the climate to which the unit is exposed.

In addition to maintenance costs attributable to the control unit, a new facility will incur additional costs in maintaining the vapor recovery equipment installed at the loading racks. The vapor return line requires periodic replacement due to wear. These costs are estimated to average $200 per rack annually, plus $200 per facility for parts such as couplers.

Regulatory Alternatives II and IV require the owner or operator of an affected terminal to restrict product loadings of gasoline tank trucks to those which have passed an annual vapor-tight test. The annual testing plus average repair cost has been estimated to total approximately \$134 per tank truck (4 labor hours at \$21 per hour, plus \$50 for materials).[43] An estimate of \$150/yr for each truck was assumed in the cost analysis. Table 8-24 shows the cost for each model plant to perform annual vapor-tight testing.

8.2.2.3 Gasoline Recovery Cost Credits. The CA, CRA, and REF type vapor control units recover and liquify VOC vapors and return the recovered product to storage. Cost credits for this recovered product are calculated from the gasoline throughput, system leakage, and degree of emission control achieved by the recovery unit.

As indicated in Section 6.3 of Chapter 6, the vapor-tight criteria, as defined in the tank truck CTG, are expected to limit truck leakage to an average of 10 percent. Alternative III, which does not restrict loading to vapor-tight gasoline tank trucks, will result in 30 percent leakage for the average delivery tank. The uncontrolled emission rate is assumed to be 960 mg/liter (submerged loading, balance service).[44] All VOC vapors which are not exhausted from the control unit or lost to the atmosphere through tank truck leakage are assumed to be recovered as liquid product. For example, under Alternative II, the gasoline recovery rate would be:

$$960 \text{ mg/liter} - (0.10)(960 \text{ mg/liter}) - 80 \text{ mg/liter} = 784 \text{ mg/liter.}$$

Calculations for Alternatives III and IV are performed in the same manner. Recovery cost credits are calculated for each model plant by using a density factor of 0.67 kg/liter for gasoline. The nationwide average wholesale price for all grades of gasoline in mid-1979 was approximately \$0.17/liter.[45] Table 8-25 presents the calculated recovery cost credits for new facilities under Alternatives II, III, and IV, for the four model plant sizes.

8.2.2.4 Total VOC Controlled. The rates at which VOC is controlled during loading are calculated for each regulatory alternative and model plant, and expressed in mg/liter and Mg/year. This quantity is equivalent to the gasoline recovery rate, the calculation of which was described in Section 8.2.2.3. Table 8-26 presents these data, which are used in the calculation of cost-effectiveness.

Table 8-24. ANNUALIZED TANK TRUCK VAPOR-TIGHT MAINTENANCE COSTS
(Thousands of Mid-1979 Dollars)

Model Plant	Number of Trucks[a]	Annualized Cost
380,000 ℓ/day	3	0.5
950,000 ℓ/day	6	0.9
1,900,000 ℓ/day	9	1.4
3,800,000 ℓ/day	20	3.0

[a]Average from Section 114 letter responses, number of tank trucks owned by terminal.

Table 8-25. GASOLINE RECOVERY CREDITS
(Thousands of Mid-1979 Dollars)

Regulatory Alternative	Controlled Emissions (mg/ℓ)	Tank Truck Leakage (Percent)	Gasoline Recovered (mg/ℓ)	Recovery Credit ($000) Model Plant 1[a]	2[b]	3[c]	4[d]
II	80	10	784	25.5	63.8	128	255
III	35	30	637	20.7	51.8	104	207
IV	35	10	829	27.0	67.4	135	270

[a]Throughput = 380,000 ℓ/day (100,000 gal/day)

[b]Throughput = 950,000 ℓ/day (250,000 gal/day)

[c]Throughput = 1,900,000 ℓ/day (500,000 gal/day)

[d]Throughput = 3,800,000 ℓ/day (1,000,000 gal/day)

Table 8-26. INCREMENTAL VOC CONTROLLED

Regulatory Alternative	Model Plant 1[a]		2[b]		3[c]		4[d]	
	mg/ℓ	Mg/yr	mg/ℓ	Mg/yr	mg/ℓ	Mg/yr	mg/ℓ	Mg/yr
II	784	101	784	252	784	505	784	1,010
III	637	82	637	205	637	410	637	820
IV	829	107	829	267	829	535	829	1,070
III and IV (Replacement or add-on control unit only)	45.0	5.8	45.0	14.5	45.0	29.0	45.0	57.9

[a]Throughput = 380,000 ℓ/day (100,000 gal/day)

[b]Throughput = 950,000 ℓ/day (250,000 gal/day)

[c]Throughput = 1,900,000 ℓ/day (500,000 gal/day)

[d]Throughput = 3,800,000 ℓ/day (1,000,000 gal/day)

8.2.2.5 Cost-Effectiveness. The cost-effectiveness of a control option is the quotient derived by division of the annualized cost of the option by the annual amount of emission reduction realized by exercise of the option. The calculated cost-effectiveness for each control option is presented in Table 8-27. In several cases, due to the effect of the gasoline recovery cost credit, a net positive cost benefit accrues to a terminal. Generally, Regulatory Alternative IV has the best cost-effectiveness (lowest expenditure per unit of control), as a result of having the largest recovery credit.

8.2.2.6 Base Cost of Facility. Section 114 letter responses provided most of the information for this cost analysis concerning the base cost of a new facility and the operating and maintenance costs of such a facility. The largest single cost component involved in the construction of a terminal facility is the cost of storage tanks. The cost of tanks ranges from 25 to 50 percent of the total cost. Other principal cost components include land, tank trucks, loading racks, spill containment, and fire protection. Table 8-28 presents the range of contributions to the total base cost of each cost component, as well as the best estimate of the average percentage value. The total base cost estimates for the model plants are as follows:

1. 380,000 l/day - $2.6 million
2. 950,000 l/day - $4.0 million
3. 1,900,000 l/day - $5.9 million
4. 3,800,000 l/day - $9.7 million

Due to the limited amount of data available concerning the cost of new terminals, these costs are considered estimates only and can be affected significantly by geographical location and the nature of the equipment installed at the terminal.

Annual operating expenses at a terminal depend on product supply method, geographical location, location in a distribution network, and other factors. Cost elements typically include salaries and benefits, utilities, maintenance (14 to 17 percent) and taxes and insurance. Annual operating expenses for the model plants are estimated to be:

1. 380,000 l/day - $120,000
2. 950,000 l/day - $300,000

Table 8-27. COST-EFFECTIVENESS OF CONTROL OPTIONS — NEW FACILITIES
(Dollars/Kg VOC Controlled)

Regulatory Alternative	Model Plants and Control Unit Types															
	380,000 ℓ/day				950,000 ℓ/day				1,900,000 ℓ/day				3,800,000 ℓ/day			
	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
II	0.53	0.44	0.46	0.59	0.12	0.04	0.22	0.16	a	a	0.13	a	a	a	0.08	a
III	0.71	b	0.56	0.78	0.21	b	0.27	0.25	a	b	0.15	0.01	a	b	0.10	a
IV	0.49	b	0.43	0.54	0.10	b	0.21	0.14	a	b	0.12	a	a	b	0.08	a

[a]Indicates a negative net annualized cost, or cost credit.
[b]Not applicable to the CRA type control unit.

Table 8-28. FACILITY BASE COST COMPONENTS
(Thousands of Mid-1979 Dollars)

Cost Component	Relative Contribution Range (percent)	Best Estimate Average (percent)
Land	8 to 24	12
Storage Tanks	25 to 50	37
Loading Racks	2 to 6	5
Buildings	1 to 10	3
Spill Containment	2 to 3	3
Tank Trucks	0 to 20	16
General[a]	22 - 69	24

[a]Includes paving, piping, electrical service, fire protection, fencing, etc.

3. 1,900,000 l/day - $600,000

4. 3,800,000 l/day - $1,200,000

Data were obtained for model plants 2 and 3 and were extrapolated to model plants 1 and 4 based on the throughput ratio.

Loading rack operating expenses include these principal items: Meter calibration and repair, loading arm repairs and replacement of couplers, fittings, gaskets, and seals. These items apply to loading racks without vapor recovery provisions, and include both top and bottom loading racks. The average reported cost to maintain a loading rack is $7,500 per year.

8.2.3 Modified/Reconstructed Facilities

8.2.3.1 Capital Investment. Most applications of additional standards for bulk gasoline terminals are expected to involve modified or reconstructed facilities instead of newly constructed facilities. Differential costs will be incurred in complying with Regulatory Alternatives II, III, or IV. Alternative I is the baseline of control, which represents compliance with SIP regulations, so no differential costs are involved. Tables 8-29 through 8-36 present tabular costs similar to those presented for new facilities in Section 8.2.2.

The control unit purchase costs are the same as those quoted for new facilities, because the same units are used in both situations. Table 8-36 presents an exception for the case of add-on control units. The CA type add-on unit has a lower cost than the primary CA unit.[46] The cost of a TO add-on unit suitable for achieving the emission limits under Alternatives III and IV is assumed to be equivalent to the cost of a primary TO unit, based on information from manufacturers.[46,47] The installation cost averages about 85 percent of the equipment purchase cost (Section 8.2.2.1.2).

A top loaded terminal requires conversion of loading racks to bottom loading and vapor recovery in order to achieve the required emission limits. Section 114 letter responses indicate this cost to average $160,000 per rack position. The tank trucks owned by a bottom loading terminal will require retrofit to install provisions for vapor recovery. The cost of these truck conversions varies with the age of the truck, due to the different types of construction used (see

Table 8-29. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE II
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, BOTTOM LOADED — ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day				950,000 ℓ/day				1,900,000 ℓ/day				3,800,000 ℓ/day			
Vapor Processing Unit:	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]
Capital Investment																
Unit Purchase Cost	160	140	90.0	143	185	140	100	170	185	172	100	175	225	200	115	220
Unit Installation Cost	136	119	76.6	122	157	119	85.0	145	157	146	85.0	149	191	170	97.8	187
Truck Vapor Recovery Cost[k]	7.2	7.2	7.2	7.2	14.4	14.4	14.4	14.4	21.6	21.6	21.6	21.6	48.0	48.0	48.0	48.0
Annual Operating Cost																
Electricity[f]	6.6	1.5	1.5	14.7	9.9	3.8	3.7	20.3	13.3	7.5	6.9	22.8	16.8	15.7	12.9	32.6
Propane (Pilot)[g]	--	--	2.0	--	--	--	3.6	--	--	--	6.6	--	--	--	8.7	--
Maintenance	7.0	11.8	4.2	12.0	8.2	12.0	4.8	14.4	8.2	14.6	4.8	14.8	10.0	17.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	--	1.5	--	--	--	1.5	--	--	--	1.8	--	--	--
Subtotal (Direct Operating Cost)	18.0	16.7	11.1	30.1	23.0	19.2	15.5	38.1	26.4	25.5	21.7	41.0	32.0	36.1	30.6	54.6
Truck Maintenance[j]	0.5	0.5	0.5	0.5	0.9	0.9	0.9	0.9	1.4	1.4	1.4	1.4	3.0	3.0	3.0	3.0
Capital Charges	60.6	53.2	34.7	54.4	71.3	54.7	39.9	65.9	72.7	67.9	41.3	69.1	92.8	83.6	52.2	91.0
Gasoline Recovery (Credit)	25.5	25.5	--	25.5	63.8	63.8	--	63.8	128	128	--	128	255	255	--	255
Net Annualized Cost	53.6	44.9	46.3	59.5	31.4	11.0	56.3	41.1	-27.5	-33.2	64.2	-17.8	-127	-132	85.8	-106
Total VOC Controlled (Mg/yr)	101	101	101	101	252	252	252	252	505	505	505	505	1,010	1,010	1,010	1,010
Cost Effectiveness ($/kg)	0.53	0.44	0.46	0.59	0.12	0.04	0.22	0.16	(p)	(p)	0.13	(p)	(p)	(p)	0.08	(p)

Table 8-30. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE III
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, BOTTOM LOADED — ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	136	76.5	122	157	85.0	145	157	85.0	149	191	97.8	187
Truck Vapor Recovery Cost[k]	7.2	7.2	7.2	14.4	14.4	14.4	21.6	21.6	21.6	48.0	48.0	48.0
Annual Operating Costs												
Electricity[f]	6.6	1.5	14.7	9.9	3.7	20.3	13.3	6.9	22.8	16.8	12.9	32.6
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	7.0	4.2	12.0	8.2	4.8	14.4	8.2	4.8	14.8	10.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	18.0	14.6	30.1	23.0	15.5	38.1	26.4	21.7	41.0	32.0	52.2	54.6
Truck Maintenance[j]	--	--	--	--	--	--	--	--	--	--	--	--
Capital Charges	60.6	34.7	54.4	71.3	39.9	65.9	72.7	41.3	69.1	92.8	52.2	91.0
Gasoline Recovery (Credit)	20.7	--	20.7	51.8	--	51.8	104	--	104	207	--	207
Net Annualized Cost	57.9	49.3	63.8	42.5	55.4	52.2	-4.9	63.0	6.1	82.2	104	-61.4
Total VOC Controlled (Mg/yr)	82	32	82	205	205	205	410	410	410	820	820	820
Cost Effectiveness ($/kg)	0.71	0.61	0.78	0.21	0.27	0.25	(p)	0.15	0.01	(p)	0.13	(p)

Table 8-31. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE IV
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, BOTTOM LOADED — ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	136	76.5	122	157	85.0	145	157	85.0	149	191	97.8	187
Truck Vapor Recovery Cost[k]	7.2	7.2	7.2	14.4	14.4	14.4	21.6	21.6	21.6	48.0	48.0	48.0
Annual Operating Costs												
Electricity[f]	6.6	1.5	14.7	9.9	3.7	20.3	13.3	6.9	22.8	16.8	12.9	32.6
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	7.0	4.2	12.0	8.2	4.8	14.4	8.2	4.8	14.8	10.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	18.0	11.1	30.1	23.0	15.5	38.1	26.4	21.7	41.0	32.0	30.6	54.6
Truck Maintenance[j]	0.5	0.5	0.5	0.9	0.9	0.9	1.4	1.4	1.4	3.0	3.0	3.0
Capital Charges	60.6	34.7	54.4	71.3	39.9	65.9	72.7	41.3	69.1	92.8	52.2	91.0
Gasoline Recovery (Credit)	27.0	--	27.0	67.4	--	67.4	135	--	135	270	--	270
Net Annualized Cost	52.1	46.3	58.0	27.8	56.3	37.5	-34.5	64.4	-23.5	-142	85.8	-121
Total VOC Controlled (Mg/yr)	107	107	107	267	267	267	535	535	535	1,070	1,070	1,070
Cost Effectiveness ($/kg)	0.49	0.43	0.54	0.10	0.21	0.14	(p)	0.1	(p)	(p)	0.08	(p)

Table 8-32. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE II
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, TOP LOADED — ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day				950,000 ℓ/day				1,950,000 ℓ/day				3,800,000 ℓ/day			
Vapor Processing Unit:	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]	CA[a]	CRA[b]	TO[c]	REF[d]
Capital Investment																
Unit Purchase Cost	160	140	90.0	143	185	140	100	170	185	172	100	175	225	200	115	220
Unit Installation Cost	136	119	76.5	122	157	119	85	145	157	146	85	149	191	170	97.8	187
Rack Conversion Cost[l]	320	320	320	320	480	480	480	480	480	480	480	480	640	640	640	640
Truck Conversion Cost[m]	14.4	14.4	14.4	14.4	28.8	28.8	28.8	28.8	43.2	43.2	43.2	96.0	96.0	96.0	96.0	96.0
Annual Operating Cost																
Electricity[f]	6.6	1.5	1.5	14.7	9.9	3.8	3.7	20.3	13.3	7.5	6.9	22.8	16.8	15.7	12.9	32.6
Propane (Pilot)[g]	--	--	2.0	--	--	--	3.6	--	--	--	6.6	--	--	--	8.7	--
Maintenance	7.0	11.8	4.2	12.0	8.2	12.0	4.8	14.4	8.2	14.6	4.8	14.8	10.0	17.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	--	1.5	--	--	--	1.5	--	--	--	1.8	--	--	--
Subtotal (Direct Operating Cost)	18.0	16.7	11.1	30.1	23.0	19.2	15.5	38.1	26.4	25.5	21.7	41.0	32.0	36.1	30.6	54.6
Truck Maintenance[j]	0.5	0.5	0.5	0.5	0.9	0.9	0.9	0.9	1.4	1.4	1.4	1.4	3.0	3.0	3.0	3.0
Capital Charges	126	119	100	120	170	154	139	165	173	168	142	169	230	221	190	229
Gasoline Recovery (Credit)	25.5	25.5	--	25.5	63.8	63.8	--	63.8	128	128	--	128	255	255	--	255
Net Annualized Cost	119	111	112	125	130	110	156	140	72.8	66.9	165	83.4	10.0	5.1	224	31.6
Total VOC Controlled (Mg/yr)	101	101	101	101	252	252	252	252	505	505	505	505	1,010	1,010	1,010	1,010
Cost Effectiveness ($/kg)	1.18	1.10	1.11	1.24	0.52	0.44	0.62	0.56	0.14	0.13	0.33	0.17	0.01	0.01	0.22	0.03

Table 8-33. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE III
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, TOP LOADED — ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	136	76.5	122	157	85.0	145	157	85.0	149	191	97.8	187
Rack Conversion Cost[l]	320	320	320	480	480	480	480	480	480	640	640	640
Truck Conversion Cost[m]	14.4	14.4	14.4	28.8	28.8	28.8	43.2	43.2	43.2	96.0	96.0	96.0
Annual Operating Costs												
Electricity[f]	6.6	1.5	14.7	9.9	3.7	20.3	13.3	6.9	22.8	16.8	12.9	32.6
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	7.0	4.2	12.0	8.2	4.8	14.4	8.2	4.8	14.8	10.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	18.0	11.1	30.1	23.0	15.5	38.1	26.4	21.7	41.0	32.0	30.6	54.6
Truck Maintenance[j]	--	--	--	--	--	--	--	--	--	--	--	--
Capital Charges	126	100	120	170	139	165	173	142	169	230	190	229
Gasoline Recovery (Credit)	20.7	--	20.7	51.8	--	51.8	104	--	104	207	--	207
Net Annualized Cost	123	111	129	141	155	151	95.4	164	106	55.0	221	76.6
Total VOC Controlled (Mg/yr)	82	82	82	205	205	205	410	410	410	820	820	820
Cost Effectiveness ($/kg)	1.50	1.35	1.57	0.69	0.75	0.74	0.23	0.40	0.26	0.07	0.27	0.09

Table 8-34. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVE IV
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, TOP LOADED — ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	136	76.5	122	157	85.0	145	157	85.0	149	191	97.8	187
Rack Conversion Cost[l]	320	320	320	480	480	480	480	480	480	640	640	640
Truck Conversion Cost[m]	14.4	14.4	14.4	28.8	28.8	28.8	43.2	43.2	43.2	96.0	96.0	96.0
Annual Operating Costs												
Electricity[f]	6.6	1.5	14.7	9.9	3.7	20.3	13.3	6.9	22.8	16.8	12.9	32.6
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	7.4	4.6	12.4	8.4	5.0	14.6	8.4	5.0	15.0	10.0	5.6	18.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	18.0	11.1	30.1	23.0	15.5	38.1	26.4	21.7	41.0	32.0	30.6	54.6
Truck Maintenance[j]	0.5	0.5	0.5	0.9	0.9	0.9	1.4	1.4	1.4	3.0	3.0	3.0
Capital Charges	126	100	120	170	139	165	173	142	169	230	190	229
Gasoline Recovery (Credit)	27.0	--	27.0	67.4	--	67.4	135	--	135	270	--	270
Net Annualized Cost	118	112	124	127	155	137	65.8	165	76.4	-5.0	224	16.6
Total VOC Controlled (Mg/yr)	107	107	107	267	267	267	535	535	535	1070	1070	1070
Cost Effectiveness ($/kg)	1.10	1.05	1.16	0.48	0.58	0.51	0.12	0.31	0.14	(P)	0.21	0.02

Table 8-35. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVES III & IV
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, UNIT REPLACED — NON-ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day			950,000 ℓ/day			1,900,000 ℓ/day			3,800,000 ℓ/day		
Vapor Processing Unit:	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]	CA[a]	TO[c]	REF[d]
Capital Investment												
Unit Purchase Cost	160	90.0	143	185	100	170	185	100	175	225	115	220
Unit Installation Cost	32.0	18.0	28.6	37.0	20.0	34.0	37.0	20.0	35.0	45.0	23.0	44.0
Salvage Value (Credit)[n]	7.0	7.0	7.0	7.0	7.0	7.0	8.6	8.6	8.6	10.0	10.0	10.0
Annual Operating Costs												
Electricity[f]	5.1	0	13.2	6.1	-0.1	16.5	5.8	-0.6	15.3	1.1	-2.8	16.9
Propane (Pilot)[g]	--	2.0	--	--	3.6	--	--	6.6	--	--	8.7	--
Maintenance	-4.8	-7.6	0.2	-3.8	-7.2	2.4	-6.4	-9.8	0.2	-7.0	-11.4	1.6
Operating Labor[h]	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Replacement[i]	1.0	--	--	1.5	--	--	1.5	--	--	1.8	--	--
Subtotal (Direct Operating Cost)	1.3	-5.6	13.4	3.8	-3.7	18.9	0.9	-3.8	15.5	-4.1	-5.5	18.5
Capital Charges	37.0	20.2	32.9	43.0	22.6	39.4	42.7	22.3	40.3	52.0	25.6	50.8
Gasoline Recovery (Credit)	1.5	-28.3	1.5	3.7	-70.8	3.7	7.3	-142	7.3	14.7	-283	14.7
Net Annualized Cost	36.8	42.9	44.8	43.1	89.7	54.6	36.3	161	48.5	33.2	303	54.6
Total VOC Controlled (Mg/yr)	5.8	5.8	5.8	14.5	14.5	14.5	29.0	29.0	29.0	57.9	57.9	57.9
Cost Effectiveness ($/kg)	6.34	7.40	7.72	2.97	6.19	3.77	1.25	5.53	1.67	0.57	5.23	0.94

Table 8-36. ESTIMATED CONTROL COSTS FOR REGULATORY ALTERNATIVES III & IV
(Thousands of Mid-1979 Dollars)
EXISTING FACILITY, SECONDARY UNIT ADDED ON — NON-ATTAINMENT AREA

Gasoline Throughput:	380,000 ℓ/day		950,000 ℓ/day		1,900,000 ℓ/day		3,800,000 ℓ/day	
Vapor Processing Unit:	CA[a]	TO[c]	CA[a]	TO[c]	CA[a]	TO[c]	CA[a]	TO[c]
Capital Investment								
Unit Purchase Cost	50.0	90.0	66.0	100	66.0	100	81.0	115
Unit Installation Cost	25.0	45.0	33.0	50.0	33.0	50.0	40.5	57.5
Annual Operating Costs								
Electricity[f]	0.1	1.5	0.1	2.1	0.1	2.1	0.1	3.0
Propane (Pilot)[g]	--	2.0	--	3.6	--	6.6	--	8.7
Maintenance	2.0	3.6	2.6	4.0	2.6	4.0	3.2	4.6
Operating Labor[h]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Carbon Replacement[i]	0.5	--	0.8	--	0.8	--	0.9	--
Subtotal (Direct Operating Costs)	6.0	10.5	6.9	13.1	6.9	16.1	7.6	19.7
Capital Charges	15.0	27.0	19.8	30.0	19.8	30.0	24.3	34.5
Gasoline Recovery (Credit)	1.5	--	3.7	--	7.3	--	14.7	--
Net Annualized Cost	19.5	37.5	23.0	43.1	19.4	46.1	17.2	54.2
Total VOC Controlled (Mg/yr)	5.8	5.8	14.5	14.5	29.0	29.0	57.9	57.9
Cost Effectiveness ($/kg)	3.36	6.47	1.59	2.97	0.67	1.59	0.30	0.94

NOTES FOR TABLES 8-29 THROUGH 8-36

[a]CA = Carbon Adsorption Unit.

[b]CRA = Compression-Refrigeration-Absorption Unit.

[c]TO = Thermal Oxidizer Unit.

[d]REF = Refrigeration Unit.

[e]Additional cost required for vapor collection equipment on new tank trucks.

[f]Electricity costs are based on average consumption rates reported by manufacturers.

[g]Propane for pilot estimated at 12.5 liters per hour based on manufacturers' reported consumption.

[h]Daily inspections at one hour per day, plus a monthly visual inspection for liquid or vapor leaks in the vapor collection and processing systems.

[i]Estimated carbon replacement period is ten years.

[j]Cost to perform annual vapor-tight testing.

Average number of terminal-owned trucks:

380,000	l/day	3
950,000	l/day	6
1,900,000	l/day	9
3,800,00	l/day	20

[k]Cost of installing vapor collection equipment on existing bottom loading tank trucks.

[l]Cost of converting top loading racks to bottom loading and vapor recovery.

[m]Cost of retrofitting existing top loading tank trucks with bottom loading and vapor collection equipment.

[n]Cost credit for salvage of replaced unit. Estimated at five percent of the current CRA unit purchase cost.

[p]Cost-effectiveness not calculated because net annualized cost is a negative quantity (cost credit).

Section 8.1.3.2). The average cost of converting to bottom loading and vapor recovery is $6,400,[48] of which approximately $2,400 is attributable to vapor recovery.

A terminal in a regulated (non-attainment) area may choose the option of replacing an existing control unit with a more efficient unit to comply with additional regulations. Information previously supplied to EPA indicates that a salvage value cost credit of 5 percent of equipment cost is a reasonable estimate.

8.2.3.2 Annualized Costs. The annualized operating costs use the same factors and calculation methods as were used to calculate operating costs for new facilities (Tables 8-21 and 8-22).

In the case of replacement control units, the costs shown reflect the differential costs to a terminal which replaces a CRA, CRC, or LOA type unit with a CA, TO, or REF unit (Table 8-35) to meet the lower emission levels required by Alternative III. Table 8-36 presents differential costs due to the addition of a CA or TO unit to an existing CRA, CRC, or LOA unit. Carbon replacement costs were estimated at one-half the cost attributable to primary CA units. Gasoline recovery cost credits result from the change in system emissions from 80 mg/liter to 35 mg/liter. The total VOC controlled (Mg/yr) similarly reflects a differential quantity resulting from the change in total system emissions. Costs to perform annual vapor-tight testing on gasoline tank trucks are the same as those for new facilities. The cost-effectiveness of each control option is presented in Table 8-37.

8.2.4 Compliance Costs.

Compliance costs are those costs involved in demonstrating that a terminal's vapor processing system complies with the applicable standards. These costs occur as a result of two principal items: performance testing and continuous monitoring.

Performance tests are required to be performed shortly after initial startup and at other times as prescribed by the Administrator.[49,50] The required performance test demonstrating a facility's ability to operate within the limits of applicable standards would involve an additional cost to the facility. The test method to be followed is described in Appendix D. The test cost will vary with the type of

Table 8-37. COST-EFFECTIVENESS OF CONTROL OPTIONS — EXISTING FACILITIES
(Dollars/kg VOC Controlled)

Facility Classification[a]	Regulatory Alternative	Model Plants and Control Unit Types															
		380,000 ℓ/day				950,000 ℓ/day				1,900,000 ℓ/day				3,800,000 ℓ/day			
		CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
A	II	0.53	0.44	0.46	0.59	0.12	0.04	0.22	0.16	b	---	0.13	b	b	b	0.08	b
	III	0.71	c	0.61	0.78	0.21	c	0.27	0.25	b	c	0.15	0.01	b	c	0.13	b
	IV	0.49	c	0.43	0.54	0.10	c	0.21	0.14	b	c	0.12	b	b	c	0.08	b
B	II	1.18	1.10	1.11	1.24	0.52	0.44	0.62	0.56	0.14	0.13	0.33	0.17	0.01	0.01	0.22	0.03
	III	1.50	c	1.35	1.57	0.69	c	0.75	0.74	0.23	c	0.40	0.26	0.07	c	0.27	0.09
	IV	1.10	c	1.05	1.16	0.48	c	0.58	0.51	0.12	c	0.31	0.14	b	c	0.21	0.02
C	III and IV	6.34	c	7.40	7.72	2.97	c	6.19	3.77	1.25	c	5.53	1.67	0.57	c	5.23	0.94
D	III and IV	3.36	c	6.47	c	1.59	c	2.97	c	0.67	c	1.59	c	0.30	c	0.94	c

[a]Classification A: Bottom loading facility in area unaffected by SIP regulations.
Classification B: Top loading facility in area unaffected by SIP regulations.
Classification C: Facility replacing previous control unit with more efficient unit.
Classification D: Facility adding on a secondary, or back-up, control unit.

[b]Indicates a negative net annualized cost, or cost credit.

[c]Not applicable to this type of control unit.

vapor control processor in use, but is assumed to be the same for all of the model plants. Thermal oxidizer units require more field measurements during testing, and thus more test personnel. The other processors are all considered to involve the same testing costs. In addition, a requirement for continuous monitoring would involve an annualized cost for monitor operation as well as the capital charges resulting from equipment purchase and installation. Monitoring costs vary according to the type of monitoring system chosen for use, and the auxiliary equipment necessary to calibrate and operate the system. The type of data recording equipment and the intended use of the collected data are also factors affecting costs. Continuous monitors may include a system to measure and record the VOC concentration at the processor outlet, or a system to measure some other process variable which provides an indirect indication of system performance.

Three performance test and continuous monitoring regulatory options have been costed in this analysis. Option 1 requires only that a performance test be performed at startup of the new facility. Option 2 includes the same performance test requirement as Option 1, plus the installation and operation of a system which monitors a process parameter of the vapor processor. Examples of such systems include monitors of temperature in the case of refrigeration or thermal oxidizer units, and liquid recovery rate for all vapor processors except the oxidizer. Although this type of equipment may be supplied as part of some vapor processing systems, it is assumed for this analysis that the equipment must be purchased and operated independently from the main processor. Option 3 includes the same performance test requirement, plus the installation and operation of a continuous VOC monitoring system. This is by far the most expensive option, because of the high installed and operating costs of this type of analyzer in comparision to the simpler parameter monitors required under Option 2. The following paragraphs present the estimated maximum costs associated with each of the options.

Option 1. The cost of conducting a performance test includes planning, travel, calibration, testing, lab analysis, and report preparation. These costs are assumed to be the same for all of the control unit types, except for the thermal oxidizer, whose testing costs are higher due to the additional manpower required. Manpower costs assume the utilization of testing contractors, at a charge of $30 per hour. Testing may require either one day or three days to perform.

Option 2. The costs associated with the monitoring of a process parameter are assumed to be the same for all types of vapor processors. Annualized costs are calculated by adding the capital charges on capital investment to the annual operating cost of the system. Capital charges are based on an assumption of 10 percent interest and a 5-year monitoring equipment useful life, with a tax rate of 4 percent. Operating costs include data recording supplies and calibration and maintenance labor costs. The performance test costs are the same as those in Option 1.

Option 3. Continuous monitoring of outlet VOC concentration is assumed to involve the same costs for all of the control unit types, except for the thermal oxidizer, which requires a CO_2/CO_2 analyzer and additional data recording capability. Annualized costs are calculated using the same assumptions as in Option 2. The performance test costs are the same as those in Option 1. Table 8-38 presents the costs incurred by a facility in complying with the requirements of each of the three options.

8.2.5 Tank Truck Industry Control Costs

Independent owners and operators of the gasoline tank trucks transporting liquid petroleum products from bulk terminals will incur additional costs as a result of the regulatory alternatives. Incremental costs to the oil companies which operate tank trucks at their own terminals have been outlined in previous sections, both for new facilities (Sections 8.2.2.1.3 and 8.2.2.2) and for existing facilities (Sections 8.2.3.1 and 8.2.3.2). The costs to for-hire tank truck companies are included as a separate but related impact because the operations of such companies are intimately related to those of bulk terminals, and many of these companies are small and may be less able to afford additional costs. The costs to these companies are expected to include the capital investment necessary to convert tank trucks to

Table 8-38. CAPITAL INVESTMENT AND ANNUALIZED COST FOR THREE COMPLIANCE OPTIONS[51]
(First Quarter 1980 Dollars)

Option	Vapor Processor	CAPITAL INVESTMENT		ANNUALIZED COST	
		1-day test	3-day test	1-day test	3-day test
1[a]	Thermal Oxidizer	10,000[b]	15,000[b]	2,000[c]	3,000[c]
	Other Processors	8,000[b]	12,000[b]	1,600[c]	2,400[c]
2[d]	Thermal Oxidizer	15,000[e]	20,000[e]	6,000[f]	7,000[f]
	Other Processors	13,000[e]	17,000[e]	5,600[f]	6,400[f]
3[g]	Thermal Oxidizer	29,000[h]	34,000[h]	20,800[i]	22,800[i]
	Other Processors	21,000[h]	25,000[h]	17,700[i]	19,100[i]

[a]Performance test only.

[b]Cost per test.

[c]Assumes one test in the first five years of facility operation.

[d]Performance test and continuous monitoring of process parameter.

[e]Includes one test plus $5,000 equipment cost.

[f]Includes capital charges on investment plus $2,500 per year operating cost.

[g]Performance test and continuous monitoring of outlet VOC concentration.

[h]Includes one test plus equipment cost of $19,000 for thermal oxidizer monitors, and $13,000 for all other processors.

[i]Includes capital charges on investment plus operating cost of $13,100 per year for thermal oxidizer monitors, and $12,200 for all other processors.

a bottom loading configuration and to install vapor recovery equipment, and the annualized costs of maintaining the vapor recovery equipment and performing yearly vapor-tight tests on the delivery tanks.

8.2.5.1 Capital Investment. The costs of retrofitting bottom loading and vapor recovery equipment on existing tank trucks were discussed in Section 8.2.3.1. The average cost of converting tank trucks to bottom loading and adding vapor recovery equipment would be the same for a for-hire tank truck company as for a bulk terminal. The different costs in individual situations would depend in part on whether the company or terminal had its own facilities for performing conversion work or had the work performed at an outside shop. As discussed earlier, bottom loading conversions average about $4,000 per tank truck, and the addition of vapor recovery provisions averages about $2,400 per tank truck.

As discussed in Section 3.2.2.3 of Chapter 3, about 23 percent of the gasoline tank trucks do not have bottom loading provisions. The trend is toward increased use of bottom loading, however, and this percentage could be considerably lower by 1982. If 23 percent, or 90, of the 390 affected for-hire tank trucks (Section 8.1.3.2) required both bottom loading and vapor recovery retrofitting by 1985, the capital investment required would be:

(90 tank trucks) X ($6,400/tank truck) = $576,000.

The remaining 300 vehicles would already use bottom loading, and would thus require vapor recovery provisions only. The total capital cost for these tank trucks would be:

(300 tank trucks) X ($2,400/tank truck) = $720,000.

The total capital cost accruing to the for-hire tank truck industry by 1985 would be the total of these two figures, or $1.3 million. This cost would be the same under Regulatory Alternative II, III, or IV.

8.2.5.2 Annualized Cost. The annualized cost due to retrofitted tank trucks includes the cost of maintaining the vapor recovery equipment (Alternatives II, III, and IV) and of performing annual vapor-tight testing (Alternatives II and IV). Capital charges on the initial investment on the equipment are also included. Capital charges are calculated using the capital recovery factor described in Table 8-21.

Assuming an interest rate of 10 percent and an equipment life of 12 years, capital charges would total:

($1.3 million) X (19 percent) = $247,000/yr.

Information from trade organizations and oil companies indicates that the cost to maintain the vapor recovery equipment on a tank truck is approximately $1,000 per year.[52,53,54] The cost to perform a vapor-tight test, including the average necessary repair cost, is about $150 per year (Section 8.2.2.2). Thus, the total annualized cost in 1985 for 390 tank trucks under Alternatives II and IV would be:

390 X ($1,000/yr + $150/yr) + $247,000/yr = $0.7 million.

Under Alternative III, no vapor-tight testing would be required, so the total annualized cost in 1985 would be:

390 X ($1,000/yr) + $247,000/yr = $0.6 million.

8.2.5.3 Control Cost Impact on Model Firms. For the purpose of analyzing the economic impact of the regulatory alternatives on the tank truck model firms (Section 8.4.2), capital and annualized costs were developed for the four models developed in Section 6.2.5 of Chapter 6. Annualized costs were calculated for Alternatives II and IV, as a worst case, because these costs are slightly higher than those under Alternative III. Two scenarios of likely control costs were considered. In Scenario 1, the affected tank trucks at each model firm are already in the bottom loading configuration and require only the addition of vapor collection equipment. In Scenario 2, the affected tank trucks also need conversion from top loading to bottom loading. An individual tank truck firm is expected to be affected under one or the other of these two scenarios.

It was assumed for model firms 1 and 2 that all tank trucks would require controls. For model firms 3 and 4, it was assumed that only 50 percent of a firm's trucks would require controls. This assumption was made based on the fact that not all of a large firm's trucks would serve regulated terminals and so be subject to the regulation. A 50 percent participation rate was selected as representative. Consequently, control cost estimates for 15 and 50 trucks were applied to these two model firms. However, revenue and expenditure estimates were based on the operation of 30 and 100 tank trucks for model firms 3 and 4, respectively (see Section 8.4.2). Table 8-39 presents the control cost estimates for the model firms.

8.2.6 Nationwide Control Cost Summary

This section summarizes the cost impact of each regulatory alternative on the bulk gasoline terminal and for-hire tank truck industries through the years 1985 and 1990. The total capital investment through these years, as well as the total annualized costs and cost-effectiveness in these two years, are calculated for all of the affected facilities and tank trucks expected throughout this time period (see Table 8-12 and Section 8.2.5.1).

The presented costs are composed of averages based on the estimated distributions of control processor type and facility size and location, as well as the estimated number of affected for-hire tank trucks. Since SIP control regulations are expected in all non-attainment areas by 1982, the only additional costs accruing to facilities in these areas will be those resulting from replacement or add-on controls. It is expected that eight of these situations will occur by 1985, and 16 will occur by 1990. Costs calculated for the two smallest sized facilities, 380,000 and 950,000 liters per day, are averages for all types of processors. Costs for the two largest sized facilities, 1,900,000 and 3,800,000 liters per day, are averages for CA, CRA, and REF type processors. The omission of the costs for a CRA system from the calculations for Alternatives III and IV (35 mg/liter) does not affect the cost totals under these alternatives.

Most of the existing facilities expected to be affected by the regulatory alternatives will use top loading for gasoline. All new facilities which will incur additional costs as a result of the regulatory alternatives will be located in attainment areas, and are expected to use bottom loading for gasoline. Table 8-40 presents a summary of the total costs to the bulk terminal and for-hire tank truck industries and compares the cost-effectiveness of each regulatory alternative in 1985 and 1990. Compliance costs (Section 8.2.4) are not included in the table.

Table 8-39. CONTROL COST ESTIMATES FOR TANK TRUCK MODEL FIRMS
(Thousands of Mid-1980 Dollars)

	1	2	3	4
No. of Tank Truck Conversions	2	7	15	50
Scenario 1[a]				
• Annualized Costs				
Annual Control Costs	2.3	8.1	17.3	57.5
Miscellaneous Costs[b]	0.9	3.2	6.8	22.8
Total Annualized Control Costs	3.2	11.3	24.1	80.3
• Total Annualized Control Costs per Affected Trailer	1.6	1.6	1.6	1.6
• Capital Costs	4.8	16.8	36.0	120.0
Scenario 2[c]				
• Annualized Costs				
Annual Control Costs	2.3	8.1	17.3	57.5
Miscellaneous Costs[b]	2.4	8.5	18.2	60.8
Total Annualized Control Costs	4.7	16.6	35.5	118.3
• Total Annualized Control Costs per Affected Trailer	2.4	2.4	2.4	2.4
• Capital Costs	12.8	44.8	96.0	320.0

[a]Vapor collection only.

[b]Includes depreciation, property taxes, insurance, and general administrative costs. Capital costs x CRF (0.19).

[c]Vapor collection plus bottom loading conversion.

Table 8-40. TOTAL NATIONAL COST ANALYSIS OF REGULATORY ALTERNATIVES[a]
(Millions of mid-1979 Dollars)

Regulatory Alternative	CAPITAL INVESTMENT		ANNUALIZED COSTS		COST-EFFECTIVENESS ($/Mg)	
	Through 1985	Through 1990	In 1985	In 1990	In 1985	In 1990
I (baseline)	0	0	0	0	0	0
II	24.3	48.6	4.0	8.0	696	741
III	25.3	50.6	4.7	9.4	1,042	1,105
IV	25.3	50.6	4.3	8.6	650	688

[a]Includes cost impacts on both bulk terminals and for-hire tank truck companies operating at terminals.

8.3 OTHER COST CONSIDERATIONS

Operations at bulk gasoline terminals are affected by regulations concerning water pollution and solid waste, as well as by regulations protecting the health and safety of employees. Information obtained through Section 114 letter responses indicates that the costs of compliance with these regulations cover a broad range. These costs are reported to vary from State to State. Since data are limited and no breakdown by terminal size is available, the costs should be considered estimates which apply to all model plants, with the lower values applying to smaller terminals and the higher values applying to larger terminals. This is a reasonable assumption because there is more water and solid waste and more employees at the larger terminals.

Costs of compliance with the Water Pollution Control Act are reported by one major oil company as $30,000 to $672,000 per terminal since 1972, or approximately $5,000 to $112,000 per year. A second major company reports $50,000 to $300,000 per terminal annually, and a third company reports these costs as $100,000 per terminal. Waterfront terminals are expected to incur higher costs due to the requirements on dock facilities.

The Resource Conservation and Recovery Act has had less effect on terminals. The main effect has been on the disposal of tank bottoms and oil-water separator sludge. One major company reports compliance costs of only a few hundred dollars per year, while a second company has provided an annual cost range of $25,000 to $100,000 per terminal.

Compliance with Occupational Safety and Health Administration (OSHA) requirements are reported by one major oil company to have cost $2,000 to $20,000 per terminal since 1972, or about $350 to $3,500 per year. Other reported costs are $10,000 to $350,000 per year for one company, and $15,000 per year for another. A breakdown by individual cost element was not included with these cost figures.

Costs of complying with air pollution control regulations for a terminal were reported by two companies as $600,000 per year and $10,000 to $250,000 per year. These regulations include SIP limitations on emissions from storage tanks and loading operations, as well as NSPS limitations on storage tank emissions (Section 3.2.2.1). The storage tank NSPS has only a slight cost impact on a gasoline terminal.[55]

8.4 ECONOMIC IMPACT OF REGULATORY ALTERNATIVES

The purpose of this section is to present the potential economic effects of the regulatory alternatives on new, modified, and reconstructed bulk gasoline terminals, and on the for-hire tank truck companies operating at these terminals. The emphasis of the analysis is on identifying possible adverse impacts on the growth of these two industries. Other impacts to be examined are those on energy consumption, employment, price inflation, foreign trade, and balance of payments. The section is divided into two principal subsections, one concerned with the impacts on the bulk terminal industry (Section 8.4.1) and the other on the for-hire tank truck industry (Section 8.4.2). Each subsection begins with some relevant supplementary information on the respective industry, followed by a brief discusssion of the economic impact analytical methodology. The analysis for each industry is based on the model plants described in Sections 6.2.4 and 6.2.5 of Chapter 6.

8.4.1 Impacts on Bulk Gasoline Terminals

8.4.1.1 Industry Profile Data and Economic Impact Assessment Methodology. Section 8.1 contains information useful in determining how the bulk gasoline terminal industry will be affected by the regulatory alternatives. A few additional characteristics must be noted in order to understand pricing and the ability of a terminal to pass on costs to customers, elasticity of demand, and the profit-center concept as it applies to this industry.

8.4.1.1.1 Concentration and integration. In Section 8.1.1.4 it was pointed out that the major oil companies own most of the bulk gasoline terminals. In 1979, in fact, eight companies - Amoco, Chevron, Gulf, Mobil, Exxon, Shell, Atlantic Richfield, and Texaco - owned 683 gasoline terminals, or more than 40 percent of the total. The first four listed owned 495. Thirteen more companies, the "semi-majors," such as Ashland, Getty, and Sun, owned another 438 terminals.[56] The remainder were owned by 47 independent companies (marketers, wholesalers, jobbers, and warehousers), 21 of which owned only one terminal apiece. There were thus 68 firms owning bulk terminals, ranging from one extreme where four firms each owned more than 100 terminals to the other with 21 firms each owning only one.[57]

All majors and semi-majors are refiners and are integrated into terminal operations and retail distribution. However, of approximately 200 independent companies, only 47 are integrated into terminal operations. The extent of integration is not particularly relevant to the impact of the alternatives on a particular terminal, however, because bulk terminals are evaluated as "stand-alone" operations even by owners which are major oil companies.

Crude oil refined by independents is an important source of supply for majors' and semi-majors' terminal operations. Major oil companies' share of total refinery capacity is approximately equal to their share of the total number of terminals. Semi-major companies' terminal share is significantly greater than a group's share of refinery capacity.[56] Because, as indicated in Section 8.1, majors' and semi-majors' terminals also tend to have greater storage and throughput capacities than do independents', purchasing or transporting oil supplied by the 150 independents not operating terminals, in particular, is a function in majors' and semi-majors' operations. With regard to distribution to retail outlets, semi-majors, to a greater extent than independents, act as middlemen in terminal transportation operations.[58]

8.4.1.1.2 Financial profile. Because terminals are increasingly operated on a stand-alone profitability basis, financial statistics to be applied in the economic impact analysis must be estimated for both large terminals, typically owned by majors and semi-majors, and for medium and small terminals, owned by independents. However, major and semi-major oil companies are dominant U.S. corporations which neither analyze nor publish financial information on gasoline industry segments. Published financial data on independents' operations is limited to data for companies specializing in petroleum product storage and distribution at bulk stations, as well as terminals. The financial profile presented is a composite of available company and storage specialist information.

All of the majors for which information was reported had 1978 asset levels greater than $10,000 million, whereas semi-majors' assets fell primarily into the $1,100 to $5,500 million range. Table 8-41 lists aggregate sales levels and key ratios for majors and semi-majors. Since these companies do not compute transfer prices to reflect costs of terminal operations,[58] the sales data reflect revenue earned primarily through final product and, to some extent, refinery product sales. The table is therefore useful only for comparative purposes.

Selected published statistics on the wholesale petroleum products industry, which would more closely reflect the financial characteristics of individual terminals, are given in Table 8-42. The statistics are for firms with asset sizes ranging from $250 thousand to $50 million, with a mean asset size of approximately $2.9 million and an estimated mean annual sales level of $17 million.

Profitability statistics are the critical financial statistics required in the analyses. As shown in the table, the before-tax profit-to-sales ratio dropped from 2 percent in 1976-1977 to 1 percent in 1978-1979, indicating an after-tax profit-to-sales ratio shift from 1 percent to 0.5 percent, respectively. According to a trade association representative, a 1 percent to 2 percent after-tax profit-to-sales ratio would be a reasonable estimate for terminal operations.[58] In this analysis, a 1.5 percent profit before taxes will be used to ensure that, if the estimates are in error, they are on the conservative side of actual results.

Another profitability measure which can be evaluated is the return on investment (ROI). A 20.5 percent pre-tax ROI (approximately 11 percent after taxes) has been applied in a previous economic analysis.[61] This rate is, according to a trade association representative, low.[58] A 30 percent pre-tax ROI -- and so a 15 percent after-tax ROI -- will, as suggested, be applied in the analysis. Majors such as Gulf have testified to the use of a 15 percent after-tax ROI criterion. The 11 percent rate will be considered the absolute minimum acceptable rate of return.

Capital budgeting decisions can be made on the basis of an ROI or a payback period criterion. For the terminal industry, they are most frequently made on the basis of the latter, with a three to four-year criterion applied.[58]

Table 8-41. SALES AND RATIO STATISTICS[57]
MAJORS AND SEMI-MAJORS

Majors	Sales (million $)	Net Income As % of Sales	Net Income as Percent of Stockholder Equity
Exxon	$64,886	4.3%	14.0%
Mobil	32,806	3.4%	7.9%
Texaco	28,607.5	3.0%	9.3%
Gulf	20,097	4.0%	9.8%
Atlantic Richfield	12,738.8	2.5%	15.3%
Shell	11,062.9	7.4%	14.2%
Mean:	$28,366.4	4.1%	11.8%
Semi-Majors			
Continental	$ 9,535.7	4.7%	15.1%
Sun	7,428.2	4.9%	12.0%
Phillips	6,997.8	10.2%	27.1%
Union	5,955	6.4%	15.0%
Ashland	5,426	4.7%	32.2%
Cities Service	4,660.9	2.5%	6.0%
Marathon	4,509.4	5.0%	6.5%
Getty	3,514.7	8.7%	-
Tenneco	2,015	23.9%	14.5%
Kerr-McGee	2,072.4	5.7%	-
Murphy	1,191	3.9%	10.7%
Diamond Shamrock	660	-	-
Mean:	$ 4,497	7.3%	14.7%

Table 8-42. SELECTED FINANCIAL STATISTICS[60]
PETROLEUM BULK STORAGE SPECIALISTS

	2nd Quarter '78 1st Quarter '79	2nd Quarter '76 1st Quarter '77
Gross Profit as % Net Sales	12.9%	15.5%
Profit Before Taxes as % Net Sales	1.0%	2.0%
Profit Before Taxes as % Total Net Assets	1.6%	0.9%
Depreciation, Depletion, Amortization as % Sales	1.5%	1.7%
Ratio of Sales to Total Assets	3.3%	3.1%
Long-Term Debt as % Total Liabilities and Net Worth	15.9%	15.4%

8.4.1.1.3 Supply and demand. This subject has been discussed in Section 8.1.2.1. An additional fact to be noted is that while long-run demand for terminal services depends on gasoline demand, short-run demand for terminal services depends on domestic refinery supply and, particularly for independents, the supply of imported petroleum products.[62]

8.4.1.1.4 Economic impact assessment methodology. A preliminary examination of the model plant control costs in Section 8.2 showed that under some combinations of regulatory alternative and vapor processing equipment, the larger model plants would experience increases in net cash flow because of revenue from resource recovery. Smaller plants, on the other hand, would not enjoy this benefit. Another preliminary observation, based on trends in gasoline consumption and industry behavior, is that growth in terms of new facilities will probably be small. More facilities would be affected by the alternatives through modification and reconstruction than through new construction. A third point, already mentioned, is that bulk terminals tend to be treated as independent operations, from a financial standpoint, even when they are owned by a major oil company. In other words, a company will not open or keep open a terminal which is not economically viable in and of itself.

These three observations essentially dictated the assessment techniques to be applied in this analysis. These techniques should be capable of discriminating among widely varying effects of similar actions by firms of various sizes. They should be useful for existing as well as new facilities, and they should be capable of assessing the impacts of capital requirements and annual operating costs of controls on relatively small businesses for which many details of financial operation were not available. Three techniques were selected:

- Debt Service Coverage Analysis, in which cash flow changes and capital requirements associated with regulatory alternatives are investigated to determine whether growth by the industry or by individual firms would be restricted;
- Cost Pass-Through Analysis, to determine the magnitude and incidence of potential price increases; and

- Return-on-Investment Analysis, an assessment of changes in profitability which might influence decisions concerning entry to or exit from the industry.

Each analysis was applied to all four model plant sizes for all regulatory alternatives, and results are reported separately for new and modified or reconstructed facilities in Sections 8.4.1.2 and 8.4.1.3, respectively. From these analyses, it is possible to predict the impacts of the regulatory alternatives on individual terminals, and on the industry as a whole, and also to identify any differential impacts which might be felt by only one or two size classes of terminals and which might, for example, restrict small business opportunities.

In Section 8.5, the results of the analysis are applied on a different level. In compliance with Executive Order 12044, total annualized control costs are examined to ascertain whether they would exceed $100 million in any calendar year between 1980 and 1985. The possibility of price increases exceeding 5 percent is considered as a measure of significant inflationary impact. Total energy consumption by alternative control equipment is compared to a 50×10^{12} Btu per year criterion. Consideration of changes in supply of and demand for urban scarce materials, a fourth requirement of E.O. 12044, is not relevant to bulk terminals.

8.4.1.2 Impacts on New Facilities. It is important to preface this discussion with a reminder that, with gasoline demand expected to be nearly level, or increasing only slightly, over the 1980-85 period, few new bulk terminals are anticipated.[63] Approximately one new terminal per year is the projected growth rate in the absence of additional controls, with only the three larger model plant sizes represented - one or two 950,000 liter/day terminals, two 1,900,000 liter/day facilities, and one or two 3,800,000 liter/day operations in the next five years. Moreover, only those new facilities constructed in attainment areas would be differentially affected by control costs associated with the proposed controls. On an industry-wide basis, then, the expected increment of growth is quite small - five new facilities added to the more than 1,500 in existence - and the number which would be affected by the standard is potentially smaller still.

From the standpoints of a region with demand exceeding terminal capacity, and of an individual firm considering entry into the industry, however, it is still important to devote some attention to possible impacts.

8.4.1.2.1 Cash flow and capital availability. One of the crucial questions asked by a potential lender is whether a new facility, under additional controls, will generate sufficient cash flow to enable it to service the debt incurred in bringing it into existence. This is examined, in this assessment, through projection of changes in "debt service coverage ratio," which lenders commonly use for this purpose. The analysis is presented in Table 8-43.

The upper section of the table shows the baseline condition - the investment, debt, profit, and cash flow from each of the four model plants without vapor control equipment. Capital investment was estimated on the basis of discussions with equipment manufacturers and suppliers and engineers experienced in designing bulk terminals. Table 8-44 shows the components of the estimates. Long-term debt is assumed to be 40 percent of the total investment; the normal range for the industry is 25 to 40 percent, and the high end of the range was selected to permit a worst-case solution.[64] The debt is assumed to be 10-year maturity, thus the current maturity is one-tenth of the total. Depreciable assets were estimated by subtracting land, working capital, and those engineering and site preparation costs which could be identified from total investment.

The annual amount of depreciation was calculated on a straight-line basis, considering the useful life of each terminal component: 20 years for tanks, foundations, oil/water separators, electrical equipment, paving, buildings, and piping; 10 years for loading racks and associated equipment and fire protection systems; and five years for pumps, data systems, and trucks.[65] Aftertax profit was calculated as 0.015 x sales x (1 - tax rate), assuming a 46 percent tax rate and a profit before taxes of 1.5 percent of sales (see Section 8.4.1.1.2). Sales themselves were estimated by multiplying daily throughput by 340 days of operation and a mid-1979 wholesale price of $0.17* per liter

*As mentioned in Section 8.1.2.1, this corresponds to a retail price of $.229 per liter or $.869 per gallon of leaded regular.

Table 8-43. DEBT SERVICE COVERAGE RATIO FOR NEW FACILITIES
(Monetary values in $000 1979)

	380,000 T/day				950,000 T/day				1,900,000 T/day				3,800,000 T/day			
	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Baseline Facility:																
Total Investment			2,600				4,000				5,900				9,700	
Long-Term Debt (LTD)			1,000				1,600				2,360				3,880	
Current Maturity LTD (CMLTD)			104				160				236				388	
Depreciable Assets			1,680				2,620				3,760				6,300	
After-Tax Profit			178				445				890				1,779	
Depreciation			160				253				352				629	
Cash Flow (CF)			338				698				1,242				2,408	
CF÷CMLTD			3.2				4.4				5.3				6.2	
Alternative II																
Total Investment	2,902	2,865	2,772	2,871	4,354	4,271	4,197	4,327	6,260	6,236	6,103	6,242	10,156	10,110	9,953	10,147
LTD	1,342	1,305	1,212	1,311	1,954	1,871	1,797	1,927	2,720	2,696	2,563	2,702	4,336	4,290	4,133	4,327
CMLTD	134	130	121	131	195	187	178	193	272	270	256	270	434	429	413	433
After-Tax Profit	149	154	153	146	428	439	415	423	905	908	855	899	1,849	1,851	1,734	1,837
Depreciation	176	174	169	174	271	267	263	270	370	369	362	370	651	649	641	651
Cash Flow	325	328	322	320	699	706	678	693	1,275	1,277	1,217	1,269	2,500	2,500	2,375	2,488
CF÷CMLTD	2.4	2.5	2.7	2.4	3.6	3.8	3.8	3.6	4.7	4.7	4.8	4.7	5.8	5.8	5.8	5.7
Alternative III																
Cash Flow	323	NA	322	288	693	NA	678	687	1,263	NA	1,217	1,257	2,475	NA	2,376	2,464
CF÷CMLTD	2.4	NA	2.7	2.2	3.6	NA	3.8	3.6	4.6	NA	4.8	4.7	5.7	NA	5.8	5.7
Alternative IV																
Cash Flow	326	NA	322	321	701	NA	678	695	1,279	NA	1,217	1,280	2,523	NA	2,375	2,512
CF÷CMLTD	2.4	NA	2.7	2.5	3.6	NA	3.8	3.6	4.7	NA	4.8	4.7	5.8	NA	5.8	5.8

Table 8-44. ESTIMATED CAPITAL INVESTMENT FOR NEW FACILITIES ($1979)

Gasoline Throughput:	380,000 l/day	950,000 l/day	1,900,000 l/day	3,800,000 l/day
Tanks [66,67,68,69]	$405,225	$746,750	$1,181,250	$2,326,500
Tank Foundation and Dikework [68]	45,000	80,000	125,000	180,000
Make Dike Impermeable [70]	270,000	360,000	450,000	540,000
Cathodic Protection [70]	30,000	40,000	50,000	60,000
Loading Rack Platform and Superstructure [70,71,73]	40,000	60,000	60,000	80,000
Pumps [72,73]	15,000	20,000	25,000	30,000
Rack Equipment [70,71,72,73]	120,000	180,000	180,000	240,000
Oil/Water Sep. [70]	65,000	65,000	65,000	65,000
Electrical [70,71]	100,000	130,000	150,000	200,000
Data Automation System [70]	60,000	70,000	80,000	100,000
Foam Fire Protection System [70]	400,000	500,000	500,000	700,000
Paving [70]	99,000	142,000	142,000	189,000
Buildings [70]	55,000	55,000	510,000	510,000
Piping [70]	36,000	48,000	60,000	72,000
Land [70]	(8 acres) 320,000	(12 acres) 480,000	(16 acres) 640,000	(20 acres) 800,000
Trucks [74,75,76]	243,000	486,000	729,000	1,620,000
Working Capital	300,000	500,000	1,000,000	2,000,000
Approximate Total	$2.6 MM	$4.0 MM	$5.9 MM	$9.7 MM

(see Table 6-2 and Section 8.2.2.3). Annual throughput was not adjusted by a capacity utilization rate because, as explained in Section 8.1.1.3, it is already a measure of the average volume of product delivered. The sum of after-tax profit and depreciation approximates cash flow. For simplicity, investment tax credit was not considered, since it would not change significantly for a given model plant from one alternative to another.

The ratio of cash flow to current maturity of long-term debt (CMLTD) is the debt service covered ratio. It ranges from 3.2 for the 380,000 liters/day model plant to 6.2 for the 3,800,000 liters/day plant. A ratio of 2:1 or higher is desirable, but many lenders will accept 1.5:1. A ratio of 1:1 is considered weak.[77]

The remainder of Table 8-43 is a presentation of changes in debt service coverage ratio as a result of implementation of the various regulatory alternatives whose costs are given in Tables 8-17 through 8-19. The first step followed in the methodology was to add the total investment cost for each vapor control system to the baseline investment. New long-term debt and CMLTD could then be determined. After-control depreciations (assuming 10-year, straight-line for the control equipment) were then calculated by adding 10 percent of the control equipment cost to baseline depreciation. After-control profit was determined under the assumption of a tax rate of 46 percent (the maximum federal corporate income tax rate for 1979 and succeeding years), by deducting 54 percent of the annualized control costs from the baseline profit. This is a worst case condition, for it assumes no pass-through of control costs. The sum of depreciation and profit was the new cash flow. It should be noted that cash flow increases under many alternative and equipment combinations for the largest two models. New ratios were then calculated; in no case was the ratio for any combination of regulatory alternative and control option as low as 2:1.

The ratios in Table 8-43 are somewhat overstated because interest, which should be included in debt service and thus in the denominator, is actually deducted from profit, in the numerator, as part of the annualized control costs. Only in the worst case - the combination of

Alternative III and an REF unit for the smallest plant, would correcting this cause the ratio to fall below 2.0; assuming an interest rate of 10 percent of the full amount of the long-term debt:

$$\frac{288 + .54(0.10 \times 1{,}311)}{131 + .54(0.10 \times 1{,}311)} = 1.8$$

The next worst case, the same combination but with Alternative II, yields:

$$\frac{320 + .54(0.10 \times 1{,}311)}{131 + .54(0.10 \times 1{,}311)} = 1.9$$

A loan would probably be granted in both cases. Corrected ratios exceed 2.0 for all other combinations.

To the extent that it can pass through control costs, a firm may improve its debt service coverage ratio. For example, under conditions of full cost pass-through, the ratios for the worst case described above would become:

$$\frac{352 + .54(0.10 \times 1{,}311)}{131 + .54(0.10 \times 1{,}311)} \doteq 2.1$$

To avoid unnecessary complication in calculation and presentation, neither the interest correction nor the cost pass-through adjustment was applied to the debt service coverage ratios in Table 8-43.

The conclusion to be drawn from the debt service coverage analysis is that, all other things being equal, the implementation of any of the regulatory alternatives would not restrict industry growth through adverse effects on capital availability. This is true regardless of model plant size, indicating that opportunity for small businesses would not be curtailed.

8.4.1.2.2 <u>Price and profitability</u>. The extent to which bulk terminal operators can pass control costs through to dealers and other customers in the form of higher prices depends on demand elasticity. If demand for terminal services is relatively inelastic, as it has been in the past (see Section 8.1.2.1), control costs can be shifted forward through price increases. Net earnings would then be largely unaffected by any of the regulatory alternatives. If, on the other hand, demand is relatively elastic, as it might become at the price levels anticipated in 1980 and 1981, control costs could only partially be passed through, if at all. They would then have a negative impact on profitability.

(see Table 6-2 and Section 8.2.2.3). Annual throughput was not adjusted by a capacity utilization rate because, as explained in Section 8.1.1.3, it is already a measure of the average volume of product delivered. The sum of after-tax profit and depreciation approximates cash flow. For simplicity, investment tax credit was not considered, since it would not change significantly for a given model plant from one alternative to another.

The ratio of cash flow to current maturity of long-term debt (CMLTD) is the debt service covered ratio. It ranges from 3.2 for the 380,000 liters/day model plant to 6.2 for the 3,800,000 liters/day plant. A ratio of 2:1 or higher is desirable, but many lenders will accept 1.5:1. A ratio of 1:1 is considered weak.[77]

The remainder of Table 8-43 is a presentation of changes in debt service coverage ratio as a result of implementation of the various regulatory alternatives whose costs are given in Tables 8-17 through 8-19. The first step followed in the methodology was to add the total investment cost for each vapor control system to the baseline investment. New long-term debt and CMLTD could then be determined. After-control depreciations (assuming 10-year, straight-line for the control equipment) were then calculated by adding 10 percent of the control equipment cost to baseline depreciation. After-control profit was determined under the assumption of a tax rate of 46 percent (the maximum federal corporate income tax rate for 1979 and succeeding years), by deducting 54 percent of the annualized control costs from the baseline profit. This is a worst case condition, for it assumes no pass-through of control costs. The sum of depreciation and profit was the new cash flow. It should be noted that cash flow increases under many alternative and equipment combinations for the largest two models. New ratios were then calculated; in no case was the ratio for any combination of regulatory alternative and control option as low as 2:1.

The ratios in Table 8-43 are somewhat overstated because interest, which should be included in debt service and thus in the denominator, is actually deducted from profit, in the numerator, as part of the annualized control costs. Only in the worst case - the combination of

Table 8-45. MAXIMUM PERCENTAGE PRICE INCREASES, COST PASS-THROUGH: NEW FACILITIES[a]

Gasoline Throughput:	380,000 l/day				950,000 l/day				1,900,000 l/day				3,800,000 l/day			
Vapor Processing Unit:	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Regulatory Alternative																
II	.24	.2	.21	.27	.06	.02	.1	.07	(.03)	(.03)	.06	(.02)	(.06)	(.06)	.04	(.05)
III	.26	--	.2	.29	.08	--	.1	.09	(.01)	--	.06	.005	(.04)	--	.04	(.03)
IV	.24	--	.21	.26	.05	--	.1	.07	(.03)	--	.06	(.03)	(.08)	--	.04	(.07)

[a]( ) indicates control cost savings, which may result in price reductions.

8.4.1.2.2.2 Profitability analysis. Return-on-investment (ROI) analysis provides the means to determine whether any of the regulatory alternatives would curtail growth that might otherwise occur by making investment in new bulk terminals unattractive. In the case of new facilities, the technique was applied by first calculating pre-control ROI for each model plant as the ratio of baseline or pre-control profit to total investment in the baseline facility, expressed as a percentage. The profit and investment values are the same as those which appear in Table 8-43. Then after-control profit was calculated for each alternative, as pre-control profit less 0.54 x the annualized control costs from Tables 8-17 through 8-19. After-control investment was determined in the same way as for the debt service coverage analysis (Section 8.4.1.2.1) and appears in Table 8-43. After-control ROI could then be determined and compared with pre-control ROI and with the industry average of 15 percent.[58]

The pre-control ROIs for each model facility size are:

380,000 liters/day	6.8 percent
950,000 liters/day	11.1 percent
1,900,000 liters/day	15.1 percent
3,800,000 liters/day	18.3 percent

Since ROIs for the two smaller facilities fall below the 15 percent industry criterion, it is unlikely that investment would be made in new terminals of these sizes. This is generally consistent with the new facilities projection (Section 7.1.2), prepared in advance of this analysis, in which most growth is expected to occur in the form of the larger terminals. After-control ROIs are presented in Table 8-46.

Comparing the results to the pre-control ROIs shows that for the two smaller model plants, any combination of regulatory alternative and vapor processing equipment would have a significant negative impact on profitability in the absence of complete control cost pass-through. For the largest model plant, there are control options which would permit compliance with any of the regulatory alternatives and full cost absorption with virtually no change in ROI. The 1,900,000 liter/day terminal could keep its decrease in ROI to 0.5 percentage points under Alternatives II and IV, and to 0.8 percentage points under

Table 8-46. AFTER-CONTROLS, AFTER-TAX RETURN ON INVESTMENT: NEW FACILITIES

Gasoline Throughput:	380,000 l/day				950,000 l/day				1,900,000 l/day				3,800,000 l/day			
Processing Unit	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Baseline	6.8%				11.1%				15.1%				18.3%			
Regulatory Alternative																
II	5.1%	5.4%	5.5%	5.1%	9.8%	10.3%	9.9%	9.8%	14.5%	14.6%	14.0%	14.4%	18.2%	18.3%	17.4%	18.1%
III	5.1%	----	5.5%	5.0%	9.7%	----	9.9%	9.6%	14.3%	----	14.0%	14.2%	18.0%	----	17.4%	17.9%
IV	5.2%	----	5.5%	5.1%	9.9%	----	9.9%	9.8%	14.5%	----	14.0%	14.6%	18.4%	----	17.4%	18.3%

Alternative III, by careful control equipment selection. Its ROI would fall only slightly below the industry average of 15 percent but would remain well above the 11 percent minimum. Since some cost pass-through appears possible, new investment in the form of 1,900,000 liter/day and 3,800,000 liter/day terminals should remain attractive.

The ROI analysis also shows that for the two largest model plants, operation under Regulatory Alternative IV would not be less profitable than under II and III and could, in some cases, be more profitable. For the two smaller models, Alternative II with CRA equipment would be slightly more profitable than Alternative IV with any control option; otherwise, all alternatives are approximately equal.

8.4.1.2.3 Impacts of performance testing and monitoring costs. Performance testing alone requires no capital investment. Depending on control equipment installed and monitoring option selected, capital expenditures for monitoring equipment are expected to range from $8,000 to $34,000. Even in the worst case, a 380,000 liter/day facility under Alternative III, using a refrigeration unit and conducting three-day tests, the uncorrected debt-service coverage ratio is only reduced from 2.2 to 2.1. This indicates that testing and monitoring costs would not affect industry growth through restriction of access to investment capital.

The annualized testing and monitoring costs, if fully absorbed by the model plants, would decrease after-tax profits by a maximum of $12,300 at thermal oxidizer installations and $10,300 where other options are used. Because the costs are the same for all four models, impacts will be most pronounced on the smallest plant, where ROIs will be reduced by approximately 0.2 percentage points. ROIs for a 950,000 liter/day plant will decline by 0.1 to 0.2 percentage points. For the two larger plants, reductions will be 0.1 percentage points or less. Testing and monitoring costs, therefore, do not appear likely to adversely affect the attractiveness of investment in 1,900,000 liter/day or 3,800,000 liter/day facilities or to alter the marginal status of a 950,000 liter/day terminal.

8.4.1.2.4 Conclusions for new facilities. Under any regulatory option and, in fact, in the absence of any, it does not appear that industry growth in the form of 380,000 liter/day bulk terminals will take place. Capital availability will not be a limiting factor, but potential pre-control returns are not attractive. Terminals in the 950,000 liter/day category, marginally attractive before controls, would have to pass through most of the control costs to remain attractive. If pass-through were not possible, there would probably be a shift toward the larger terminal sizes in any expansion of this industry. The 3,800,000 liter/day bulk terminals would appear to be attractive investments under any control option, and 1,900,000 liter/day facilities would certainly remain viable. Consequently, industry growth, in terms of the terminal sizes most likely to be constructed in the absence of a standard, would not be adversely affected by its implementation.

The rapid gasoline price increases which have occurred since control cost estimates were developed - nearly 50 percent since mid-1979 - result in reduced annualized control costs for those control options involving vapor recovery. Assuming a 50 percent increase, the effect on after-tax profit is an increase of 0.54 x 0.50 x recovery credit. Under Regulatory Alternative IV, the results would be improvements in after-tax profits of 4.9, 4.3, 4.0, and 4.0 percent for the four model plants, respectively. In terms of ROI, this signifies increases of 0.3 percent for the two smaller models and 0.5 percent for the two larger ones. The 380,000 liter/day model plant is still an unattractive investment, and the 950,000 liter/day model still must be considered marginal. The overall conclusions remain the same.

To this point in the discussion, differences between marine and pipeline terminals have not been considered. The model facilities being used in the analysis generally reflect pipeline terminal characteristics, with the principal difference being the need for a dock and associated equipment at a marine terminal. A previous study of 950,000 liter/day and 1,900,000 liter/day facilities has shown that a marine facility with the same tank capacity would require depreciable assets of from 29 to 47 percent more than a comparable pipeline terminal.[78]

This means that both CMLTD and depreciation would increase by an average of approximately 38 percent. The worst case, from an uncorrected debt service standpoint, would then become:

$$\frac{146 + 1.38(174)}{1.38(131)} = 2.1$$

The change in debt service coverage ratio is not significant.

The cost pass-through analysis would not be affected by the differences in capital investment. Their effect on profitability of marine terminals can be determined by increasing the denominator, total investment, in the ROI expression. Table 8-43 shows that depreciable assets are 65 percent of total investment, so the correction for marine terminals becomes:

Total Investment + .38(.65 x Total Investment) = 1.25 x Total Investment

Increasing the denominator by .25 is equivalent to reducing the ROI to 0.8 of the values in Table 8-46. The 380,000 liter/day and 950,000 liter/day terminals appear even less attractive as investments before controls and fall clearly below the minimum acceptable ROI after controls, in the absence of cost pass-through. The minimum ROIs for 1,900,000 liter/day and 3,800,000 liter/day terminals become 11.2 and 13.9 percent, respectively.

Few, if any, new marine terminals are expected to be constructed at all,[62] and the impact of the standard should thus be slight. However, the imposition of controls would tend to cause any new marine terminals to be in the larger size categories.

8.4.1.3 Impacts on Modified or Reconstructed Facilities. Approximately 50 bulk terminals are expected to be modified or reconstructed in the 1980-1985 period covered by this assessment. Roughly half of these will be in attainment areas and would thus experience the full economic impact of additional controls (see Section 7.1.2). The other half will be affected if either Regulatory Alternative III or IV is selected for the standard. Existing facilities were thus subjected to the same three analyses applied to new facilities in Section 8.4.1.2.

8.4.1.3.1 Cash flow and capital availability. In performing debt service coverage analysis, the four model plants were assumed to have been constructed five years ago. The total investments for new facilities were adjusted to reflect 1974 cost levels using the Chemical Engineering Plant Cost Index, in which September 1979 = 243.4 and 1974 = 165.4.[79] The resulting total investment, long-term debt, CMLTD, and depreciable assets are shown in Table 8-47. For simplicity, depreciation was assumed to be 10-year straight-line for all plant components. All other assumptions remain the same as for new facilities. Debt service coverage ratios range from 4.1 for a 380,000 liter/day terminal to 8.4 for a 3,800,000 liter/day operation.

In Chapter 5, a variety of possible reconstructions and modifications are described. Those to which a specific cost can be assigned are:[80]

Adding or replacing a loading rack	\$90,000-\$160,000
Converting a rack from top to bottom loading	\$90,000-\$160,000
Adding a loading arm to an existing rack	\$25,000

For simplicity in the debt service coverage analysis, complete replacement of a loading rack with no salvage value at a cost of \$120,000 is assumed to be the reconstruction which causes the facility to become subject to controls. A cost of \$120,000 is therefore added to total investment. Then total investment, LTD, CMLTD, profit, and depreciation are adjusted in the manner described in Section 8.4.1.2.1, using various control equipment costs in Tables 8-29 through 8-36, and new debt service coverage ratios are calculated. The results are shown in Tables 8-48 through 8-51. The lowest coverage ratio is 2.4, indicating that capital availability for reconstructions and modifications would not be adversely affected by implementation of any of the regulatory alternatives. The ratios are slightly overstated as described in Section 8.4.1.2.1; correction would not cause any combination of regulatory alternative and control option to fall into the range where financing would be questionable.

8.4.1.3.2 Cost pass-through analysis. Cost pass-through analysis identical to that applied to new facilities yielded similar results, as presented in Table 8-52. The maximum pass-through, if all costs

Table 8-47. DEBT SERVICE COVERAGE RATIO, EXISTING FACILITY - BASELINE ($000)

	380,000 l/day	950,000 l/day	1,900,000 l/day	3,800,000 l/day
Existing Facility:				
Total Investment	1,770	2,720	4,010	6,600
Long-Term Debt (LTD)	710	1,090	1,600	2,640
Current Maturity LTD (CMLTD)	71	109	160	264
Depreciable Assets	1,140	1,780	2,560	4,280
After-Tax Profit	178	445	890	1,779
Depreciation	114	178	256	428
Cash Flow (CF)	292	623	1,146	2,207
CF÷CMLTD	4.1	5.7	7.2	8.4

Table 8-48. DEBT SERVICE COVERAGE RATIO, EXISTING FACILITY, BOTTOM LOADED - ATTAINMENT AREA ($000)

	380,000 l/day				950,000 l/day				1,900,000 l/day				3,800,000 l/day			
	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Alternative II																
Total Investment	2,193	2,156	2,064	2,162	3,196	3,113	3,039	3,169	4,494	4,470	4,337	4,476	7,184	7,138	6,981	7,175
LTD	877	862	826	865	1,278	1,245	1,216	1,267	1,797	1,788	1,735	1,790	2,874	2,855	2,792	2,870
CMLTD	88	86	83	86	128	124	122	127	180	179	174	179	288	285	279	287
Depreciable Assets	1,300	1,280	1,230	1,283	1,965	1,920	1,880	1,950	2,745	2,732	2,660	2,735	4,505	4,480	4,395	4,500
After-Tax Profit	149	154	153	146	428	451	414	423	904	907	855	900	1,848	1,850	1,732	1,836
Depreciation	130	128	123	128	196	192	188	195	274	273	266	274	450	448	440	450
Cash Flow	279	281	276	274	624	643	602	617	1,179	1,180	1,121	1,173	2,298	2,298	2,173	2,286
CF÷CMLTD	3.2	3.3	3.3	3.2	4.9	5.2	4.9	4.9	6.5	6.5	6.4	6.6	8.0	8.0	7.8	8.0
Alternative III																
Cash Flow	277	NA	275	271	618	NA	607	605	1,167	NA	1,122	1,161	2,273	NA	2,163	2,262
CF÷CMLTD	3.1	NA	3.3	3.2	4.8	NA	5.0	4.8	6.5	NA	6.4	6.5	7.9	NA	7.8	7.9
Alternative IV																
Cash Flow	280	NA	276	275	626	NA	603	620	1,183	NA	1,128	1,177	2,306	NA	2,173	2,294
CF÷CMLTD	3.2	NA	3.2	3.2	4.9	NA	4.9	4.9	6.6	NA	6.5	6.6	8.0	NA	7.8	8.0

Table 8-49. DEBT SERVICE COVERAGE RATIO, EXISTING FACILITY, TOP LOADED ATTAINMENT AREA ($000)

	380,000 l/day				950,000 l/day				1,900,000 l/day				3,800,000 l/day			
	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Alternative II																
Total Investment	2,520	2,483	2,390	2,489	3,691	3,609	3,534	3,664	4,995	4,971	4,838	4,977	7,872	7,826	7,669	7,863
LTD	1,008	993	956	996	1,476	1,443	1,414	1,466	1,998	1,988	1,935	1,991	3,149	3,130	3,068	3,145
CMLTD	101	99	96	100	148	144	141	147	200	199	194	199	315	313	307	314
Depreciable Assets	1,300	1,280	1,230	1,283	1,965	1,920	1,880	1,950	2,745	2,732	2,660	2,735	4,505	4,480	4,395	4,500
After-Tax Profit	114	118	111	375	386	361	369	851	851	854	801	845	1,774	1,776	1,658	1,762
Depreciation	130	128	123	128	196	192	188	195	274	273	266	274	450	448	440	450
Cash Flow	244	246	241	238	571	578	549	564	1,125	1,127	1,067	1,119	2,224	2,224	2,098	2,212
CF÷CMLTD	2.4	2.5	2.5	2.4	3.9	4.0	3.9	4.8	5.6	5.7	5.5	5.6	7.1	7.1	6.8	7.0
Alternative III																
Cash Flow	242	NA	241	236	565	NA	549	558	1,112	NA	1,067	1,107	2,199	NA	2,100	2,188
CF÷CMLTD	2.4	NA	2.5	2.4	3.8	NA	3.9	3.8	5.6	NA	5.5	5.6	6.9	NA	6.8	7.0
Alternative IV																
Cash Flow	244	NA	241	239	572	NA	549	566	1,128	NA	1,067	1,123	2,232	NA	2,098	2,220
CF÷CMLTD	2.4	NA	2.5	2.4	3.9	NA	3.9	3.9	5.6	NA	5.5	5.6	7.1	NA	6.8	7.1

Table 8-50. DEBT SERVICE COVERAGE RATIO FOR EXISTING FACILITY, UNIT REPLACED — NON-ATTAINMENT AREA ($000)

	380,000 l/day			950,000 l/day			1,900,000 l/day			3,800,000 l/day		
	CA	TO	REF	CA	TO	REF	CA	TO	REF	CA	TO	REF
Alternatives III & IV												
Total Investment	2,075	1,991	2,054	3,055	2,953	3,037	4,343	4,241	4,331	6,980	6,848	6,974
LTD	830	796	822	1,222	1,181	1,215	1,737	1,696	1,732	2,792	2,739	2,790
CMLTD	83	80	82	122	118	122	174	170	173	279	274	279
Depreciable Assets	1,293	1,223	1,276	1,958	1,873	1,943	2,736	2,651	2,726	4,495	4,385	4,490
After-Tax Profit	158	155	154	422	397	416	870	803	866	1,761	1,611	1,750
Depreciation	129	122	128	196	187	194	274	265	273	450	438	449
Cash Flow	287	277	282	618	584	610	1,145	1,068	1,139	2,211	2,049	2,199
CF÷CMLTD	3.5	3.5	3.4	5.1	4.9	5.0	6.6	6.3	6.6	7.9	7.5	7.9

Table 8-51. DEBT SERVICE COVERAGE RATIO,
EXISTING FACILITY,
SECONDARY UNIT ADDED ON
NON ATTAINMENT AREA ($000)

	380,000 l/day		950,000 l/day		1,900,000 l/day		3,800,000 l/day	
	CA	TO	CA	TO	CA	TO	CA	TO
Alternatives III & IV								
Total Investment	1,965	2,025	2,939	2,990	4,229	4,280	6,841	6,892
LTD	786	810	1,176	1,196	1,692	1,712	2,736	2,757
CMLTD	79	81	118	120	169	171	274	276
Depreciable Assets	1,190	1,230	1,846	1,880	2,626	2,660	4,361	4,395
After-Tax Profit	167	158	433	422	880	865	1,770	1,750
Depreciation	119	123	185	188	263	266	436	440
Cash Flow	286	281	618	610	1,143	1,131	2,206	2,190
CF÷CMLTD	3.6	3.5	5.2	5.1	6.7	6.6	8.1	7.9

Table 8-52. MAXIMUM PERCENTAGE PRICE INCREASES, COST PASS-THROUGH: EXISTING FACILITIES*

Gasoline Throughput:	380,000 l/day				950,000 l/day				1,900,000 l/day				3,800,000 l/day			
Vapor Processing Unit:	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Facility Description & Alternatives																
Bottom Loaded, Attainment: II	.24	.2	.21	.27	.06	.02	.1	.07	(.03)	(.03)	.06	(.02)	(.06)	(.06)	.04	(.05)
III	.26	--	.22	.29	.08	--	.1	.1	(.004)	--	.06	.006	(.04)	--	.05	(.03)
IV	.24	--	.21	.26	.05	--	.1	.07	(.03)	--	.06	(.02)	(.06)	--	.04	(.06)
Top Loaded, Attainment: II	.54	.51	.51	.57	.24	.02	.28	.25	.07.	.06	.15	.08	.005	.002	.01	.01
III	.56	--	.51	.59	.26	--	.28	.27	.09	--	.15	.1	.03	--	.1	.03
IV	.54	--	.51	.56	.23	--	.28	.25	.06	--	.15	.07	(.002)	--	.1	.008
Unit Replaced, Non-Attainment: III,IV	.17	--	.2	.2	.08	--	.16	.1	.03	--	.15	.04	.02	--	.14	.02
Unit Added, Non-Attainment: III,IV	.09	--	.17	--	.04	--	.08	--	.02	--	.04	--	.008	--	.02	--

*()indicates control cost savings, which may result in price reductions.

were passed on to the customer, would be 0.59 percent, which would have no significant inflationary or demand-related profitability impacts. This price increase would be incurred by the customers of affected terminals, who would in turn pass on the increases in varying degrees at the retail level. In any case, the resulting nationwide price increase would be likely to be negligible.

8.4.1.3.3 Profitability analysis. The analysis of ROI was performed in the same manner as for new facilities, with the exception of the estimation of the pre-controls asset base. Because an after-tax ROI of 15 percent is the industry average (Section 8.4.1.1.2), it was assumed that model existing plants were operating at this level. Estimated pre-control profits, calculated as for new plants, were divided by 0.15 to obtain asset base. To this result were added the capital costs (equipment and installation) for control equipment in Tables 8-29 through 8-36. Corresponding annualized control costs were subtracted from profits, and post-control ROIs were calculated. Table 8-53 shows the results.

One can conclude that under the assumption of no cost pass-through (which is unduly strict, as most if not all costs will be able to be passed forward), all models of existing plants would experience a decrease in profitability. It would be more severe in the case of top loaded facilities in attainment areas, where post-control ROIs range from 6.1 percent for the smallest model to 13.7 percent for the largest. Both the 380,000 liter/day and 950,000 liter/day terminals would encounter ROIs of less than 11 percent, taken to be the minimum acceptable return (see Section 8.4.1.2.1). A 380,000 liter/day plant, bottom loaded in an attainment area, would experience marginal ROIs. In all other cases and for all plant sizes, ROIs of 11 percent or higher remain possible.

8.4.1.3.4 Impacts of performance testing and monitoring costs. As in the case of new facilities, debt service coverage ratio will not be significantly lowered by the capital costs for testing and monitoring equipment (see Section 8.4.1.2.3). Consequently, terminals contemplating actions which would cause them to become affected facilities would not encounter barriers in the form of capital unavailability.

Table 8-53. AFTER-CONTROLS, AFTER-TAX RETURN ON INVESTMENT: EXISTING FACILITIES

Gasoline Throughput:	380,000 l/day				950,000 l/day				1,900,000 l/day				3,800,000 l/day			
Processing Unit	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF	CA	CRA	TO	REF
Bottom Loaded, Attainment Area																
II	9.7%	10.2%	10.7%	9.6%	12.9%	13.6%	13.1%	12.8%	14.4%	14.5%	13.9%	14.3%	15.0%	15.1%	14.3%	14.9%
III	9.5%	---	10.6%	9.5%	12.7%	---	13.1%	12.6%	14.2%	---	13.9%	14.1%	14.8%	---	14.2%	14.7%
IV	9.7%	---	10.7%	9.7%	12.9%	---	13.1%	12.9%	14.4%	---	13.9%	14.4%	15.1%	---	14.3%	15.0%
Top Loaded, Attainment Area																
II	6.3%	6.6%	7.0%	6.2%	9.8%	10.3%	9.9%	9.7%	12.5%	12.6%	12.1%	12.4%	13.6%	13.7%	12.9%	13.6%
III	6.1%	---	7.0%	6.1%	9.7%	---	9.9%	9.6%	12.3%	---	12.1%	12.2%	13.4%	---	13.0%	13.4%
IV	6.3%	---	7.0%	6.2%	9.9%	---	9.9%	9.8%	12.6%	---	12.1%	12.5%	13.7%	---	12.9%	13.6%
Unit Replaced, Non-Attainment Area III & IV	11.4%	---	11.9%	11.3%	13.2%	---	12.8%	13.1%	14.1%	---	13.2%	14.0%	14.5%	---	13.5%	14.4%
Secondary Unit Added, Non-Attainment Area III & IV	13.3%	---	11.9%	---	14.1%	---	13.5%	---	14.4%	---	14.2%	---	14.8%	---	14.5%	---

Effects on ROI range from a decrease of as much as 1.0 percentage point for the 380,000 liter/day model plant under Option 3 to a negligible change for the 3,800,000 liter/day terminal. The 380,000 liter/day existing facility, marginal unless top loaded in an attainment area, appears less viable but still marginal as an affected facility. The 950,000 liter/day model remains slightly better than marginal, except when top loaded in an attainment area where its ROI falls further below industry standards. The other models are affected very little by testing and monitoring costs.

8.4.1.3.5 Conclusions for existing facilities. Existing 380,000 liter/day top or bottom loaded facilities and 950,000 liter/day facilities, top loaded, in attainment areas, would have to pass on nearly all of the control costs in order to maintain a reasonable rate of return under any regulatory alternative. Nearly 80 percent of existing terminals are in this size range (see Section 3.1.2). However, only about 30 percent of all existing terminals will not already be controlled to at least Alternative II levels through SIPs. Consequently, if all 50 existing facilities expected to be subject to controls were in this size range, most would still experience post-control ROIs of between 11.3 and 14.1 percent, depending on the control approach selected. Only a few would fall into the categories where their profitabilities would be significantly reduced.

Existing plants in the other circumstances considered in this section should not encounter situations which would seriously affect their viability in making reconstructions or modifications under any of the regulatory alternatives.

As in the case of new facilities, gasoline price increases experienced to date and foreseeable in the near future will not alter the overall conclusions for existing facilities.

For marine terminals, the same adjustments must be made as for new facilities (Section 8.4.1.2.3). The worst case debt service coverage ratio, 2.4 for Alternative III, REF, top loaded in an attainment area (Table 8-50) becomes:

$$\frac{111 + 1.38(128)}{1.38(100)} = 2.1,$$

indicating no adverse effects in terms of capital availability. There is no change in the cost pass-through results. Multiplying all ROIs by 0.8 moves the 380,000 liter/day and 950,000 liter/day terminals below 11 percent for all regulatory alternatives, indicating that control costs would adversely affect profitability for any modified or reconstructed marine terminals in the lower size ranges. Except for top loaded, 1,900,000 liter/day facilities in attainment areas (ROI 10 percent), the two larger models would continue to experience ROIs of 11 percent or higher as marine terminals.

8.4.2 Impacts on the Independent Tank Truck Industry

In this section, the potential economic impacts of the regulatory alternatives on the independent tank truck industry are examined. Because tank trucks working directly with bulk terminals which are subject to the proposed standards would have to install controls (Section 8.2.5), existing as well as new tank truck firms would be affected. Estimation of the impact is complex to the extent that it is difficult to predict not only what proportion of a firm's tank truck fleet would require controls but how the long-term structure of the industry would be affected.

8.4.2.1 Financial Profile. Detailed operating and financial statistics on the independent tank truck industry are published annually. Information is available for the industry as a whole, for firms grouped by revenue size, and for a sample of individual firms. As shown in Table 8-54, operating expenses and revenue levels applied in the analysis were developed from sample firm data. Large differences exist in expenses and revenues per trailer among model firms 2, 3, and 4 and can be accounted for, at least in part, by the pattern in the trailer-to-tractor ratios.[81] Smaller firms evidently have fewer trailers per tractor, which probably results in more intensive use of their existing trailers. Larger expenses and revenues per trailer can thus be expected. It is also likely that the smaller firms use their tractors to pull non-owned trailers more often than do larger firms. Since revenues and expenses accrued in this manner are not separable from those attributable to owned trailers in the industry statistics,

Table 8-54. OPERATING EXPENSES AND REVENUES FOR TANK TRUCK FIRMS[82,83]

	MODEL FIRM			
	1	2	3	4
<u>Sample Firm Statistics</u>[a]				
Revenues/Firm ($000)[b]	880	1370	2064	13,024
Operating Expenses/Firm ($000)[c]	803	1238	1958	12,267
Operating Ratio[d]	91.3%	94.7%	94.9%	94.2%
No. Trailers/Firm[e]	N.A.	6	29	231.5
Operating Revenues/Trailer ($000)[f]	N.A.	218	71	56
Operating Expenses/Trailer ($000)[g]	N.A.	206	67.5	53
Trailer/Tractor Ratio	N.A.	0.84	1.29	1.47
<u>Model Firm Parameters</u>				
No. Trailers/Firm[h]	2	7	30	100
Operating Revenues/Firm ($000)[i]	657.2	1520.6	2136.1	5626.3
Operating Expenses/Firm ($000)[j]	600	1440	2025	5300
Operating Income[k]	57.2	80.6	111.1	326.3
Net Income Before Income Tax (EBIT)[l]	46.0	63.9	83.6	258.8
Net Income[m]	23.0	32.0	43.8	129.4

[a]The sample sizes for the model firms were 6 for size 1, 4 for size 2, 62 for size 3, and 111 for size 4. Statistics for the three larger firm sizes were obtained from Reference 82, with limited statistics for the small firm obtained from Reference 83.

[b]Total actual revenue ÷ number of firms sampled.

[c]Total actual operating expenses ÷ number of firms sampled.

[d]Operating expenses/firm ÷ revenues/firm.

[e]The statistical mean for each sample firm category.

[f]Revenues/firm ÷ no. trailers/firm.

[g]Operating expenses/firm ÷ no. trailers/firm.

[h]Refer to Section 6.2.5 of Chapter 6.

[i]Model firm operating expenses (note j) ÷ sample operating ratio.

[j]Estimated as sample operating expenses/trailer x number of model firm trailers. Given limited sample statistics available for model firm 1, average firm operating expenses were estimated to range from $200,000 to $400,000 (by extrapolation) with $300,000 selected as the mean.

[k]Operating revenues - operating expenses.

[l]Operating income - interest expense.

[m]EBIT x (1 - marginal tax rate). An assumed 50 percent marginal tax rate includes a Federal tax rate of 46 percent and a State and local tax rate of 4 percent.

they contribute to higher revenue-per-trailer results for smaller firms. Table 8-55 lists industry statistics applied in the analysis.

8.4.2.2 Economic Impact Analysis. Three types of economic impact analysis were performed:

1. Return-on-investment analysis,
2. Cost pass-through analysis, and
3. Debt service coverage analysis.

In return-on-investment (ROI) analysis, the impact of control costs on existing firms' viability and the attractiveness of investment in new firms is examined. If firms fully absorbed control costs, ROI would decrease. For this analysis, a more specialized parameter, the return-on-transportation investment (ROTI), was evaluated.* This indicator, which does not reflect non-transportation investment, is a commonly-used general measure of trucking industry performance.[85]

In cost pass-through analysis, the maximum price increase which would take place if firms passed control costs through to customers in the form of higher prices is examined. It is assumed here that firms will increase operating income by raising prices in order to maintain pre-control ROTI after the imposition of controls.

Whether or not firms can meet increased annual debt service costs under controls is assessed in the debt service coverage analysis. If the ratio of a firm's cash flow to current maturity long-term debt (CMLTD) is 2, debt service coverage is considered to be healthy. A ratio less than 1 indicates that annual debt service costs cannot be met and that firms will therefore find their access to capital restricted.

8.4.2.2.1 Return on transportation investment. Table 8-56 contains the appropriate data and calculations necessary for the ROTI analysis. In order to calculate ROTI, both net income and transportation investment had to be estimated for the baseline data. Sample ROTI statistics for the baseline case were available but were calculated using operating income only. From these data, transportation

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*ROTI is equal to net carrier operating income divided by carrier operating property, net, plus working capital.

Table 8-55. FINANCIAL RATIOS AND STATISTICS

Ratio	Level
Before-Tax Profit Margin (Net income before taxes ÷ gross revenues)	4.5%
Return on Transportation Investment (Operating income ÷ (net property working capital))	
Sales less than $1 million	31.10%
Sales $1-5 million	16.87%
Sales $5-10 million	20.26%
Long-Term Debt/Revenue[82,83]	
Sales less than $1 million	5.7%
Sales $1-10 million	10.3%
Interest Payment/Revenue[82,83]	
Sales less than $1 million	1.7%
Sales $1-5 million	1.1%
Sales $5-10 million	1.2%
Capital Investment/Revenue[82,83]	33.9%
Depreciation/Revenue[82,83]	5.4%
Current Maturity Long-Term Debt/Depreciation[82,83]	69.0%
Average Wholesale Price for Gasoline[a]	$ 0.170/liter
Transportation Rate for Gasoline[84]	$ 0.004/liter
Transportation Rate as a Percent of Gasoline Price	2.3%

[a]Refer to Section 8.2.2.3.

Table 8-56. ROTI ANALYSIS
($000)

	Model Firm 1	2	3	4
Baseline				
ROTI (Operating Income)	31.10%	16.90%	16.90%	20.30%
Revenue	657.20	1520.60	2136.10	5626.30
Operating Expenses	600.00	1440.00	2025.00	5300.00
Operating Income	57.20	80.60	111.10	326.30
Interest Expense	11.20	16.70	23.50	67.50
EBIT	46.00	63.90	87.60	258.80
Taxes (50%)[a]	23.00	31.95	43.80	129.40
Net Income	23.00	31.95	43.80	129.40
Transportation Investment[b]	183.92	476.92	657.40	1607.39
ROTI[c]	12.5%	6.7%	6.7%	8.1%
Scenario 1 (300 Trucks or 1% of Total Population):				
Revenue	657.20	1520.60	2136.10	5626.30
Operating Expenses[d]	603.20	1451.30	2049.10	5380.30
Operating Income	54.00	69.30	87.00	246.00
Interest Expense	11.20	16.70	23.50	67.50
EBIT	42.80	52.60	63.50	178.50
Taxes[a]	21.40	26.30	31.75	89.25
Net Income	21.40	26.30	31.75	89.25
Transportation Investment[e]	188.72	493.72	693.40	1727.39
ROTI[c]	11.3%	5.3%	4.6%	5.2%
Scenario 2 (90 Trucks or 3/10 of 1% of Total Population):				
Revenue	657.20	1520.60	2136.10	5626.30
Operating Expenses[d]	604.70	1456.60	2060.50	5418.30
Operating Income	52.50	64.00	75.60	208.00
Interest Expense	11.20	16.70	23.50	67.50
EBIT	41.30	47.30	52.10	140.50
Taxes[a]	20.65	23.65	26.05	70.25
Net Income	20.65	23.65	26.05	70.25
Transportation Investment[e]	196.72	521.72	753.40	1927.39
ROTI[c]	10.5%	4.5%	3.4%	3.6%

[a]Assumed tax rates are 46 percent for the Federal government and 4 percent for the State and local governments.

[b]Operating income ÷ ROTI (operating income).

[c]Net income ÷ transportation investment.

[d]Baseline operating expenses + annualized control costs including the additional interest expense.

[e]Baseline transportation investment + capital control costs.

investment for each model firm was estimated by dividing operating income by the original ROTI. This baseline estimate of transportation investment was then used to calculate net income ROTI for the three levels of control.

In preparing Table 8-56, demand was assumed to be totally elastic with no change in price, volume, or revenue. The control costs were assumed to be totally absorbed by the firm. Additional assumptions are explained in the footnotes to Table 8-56.

The results of the ROTI analysis suggest a decline in ROTI of 1.2 to 2.9 percentage points, or a relative decline of 9.6 to 35.8 percent for the four model firms under Scenario 1. A greater impact would result under Scenario 2, with a 2.0 to 4.5 percentage point decline in ROTI, or a relative decline of 16.0 to 55.6 percent.

8.4.2.2.2 Cost pass-through analysis. Table 8-57 presents the results of the cost pass-through analysis. Using the baseline net profit ROTI developed in Table 8-56, the pro forma income statements for the four model firms can be developed in reverse, yielding the revenue levels necessary to maintain the baseline ROTIs. In order for the model firms to achieve these specific revenue levels, control costs must be fully passed along. Full cost pass-through assumes demand to be totally inelastic.

Accordingly, control costs associated with Scenario 1 will necessitate rate increases of 0.6 percent to 1.8 percent, with the larger firms requiring the larger rate increases. The rate increase gradient for Scenario 2 follows a similar pattern, with rate increases ranging from 1.2 to 3.0 percent.

The unexpected pattern of rate increases over the four model firms is due to the pattern in the trailer-to-tractor ratio presented earlier in Table 8-54. The expected rate increase gradient should be just the opposite since the annualized control costs per trailer for model firms 1 and 2 are twice those for model firms 3 and 4. The causes both per-trailer revenues and expenses to be larger. The calculations in Table 8-58 show the absolute control cost per trailer for firms 1 and 2 is relatively small when compared to their relatively large expense per trailer.

Table 8-57. COST PASS-THROUGH ANALYSIS

	Model Firm			
	1	2	3	4
Original Revenue	657.20	1520.60	2136.10	5626.30
Scenario 1				
Maintain ROTI[a]	12.5%	6.7%	6.7%	8.1%
Transportation Investment[a]	188.72	493.72	693.40	1727.39
Necessary Net Income[b]	23.59	33.08	46.46	139.92
+ Taxes (50 percent)	23.59	33.08	46.46	139.92
NBIT	47.18	66.16	92.92	279.84
+ Interest Costs	11.20	16.70	23.50	67.50
Operating Income	58.30	82.86	116.42	347.34
+ Operating Expenses	603.20	1451.30	2049.10	5380.30
Necessary Revenues	661.50	1534.16	2165.52	5727.64
Necessary Rate Increase[c]	0.6%	0.9%	1.4%	1.8%
Scenario 2				
Maintain ROTI[a]	12.5%	6.7%	6.7%	8.1%
Transportation Investment[a]	196.72	521.72	753.4	1927.39
Necessary Net Income[b]	24.59	34.95	50.48	156.12
+ Taxes (50 percent)	24.59	34.95	50.48	156.12
NBIT	49.18	69.90	100.96	312.24
+ Interest Costs	11.20	16.70	23.50	67.50
Operating Income	60.38	86.60	124.46	379.74
+ Operating Expenses	604.70	1456.60	2060.50	5418.30
Necessary Revenues	665.08	1543.20	2184.96	5798.04
Necessary Rate Increase[c]	1.2%	1.5%	2.3%	3.0%

[a]Given in Table 8-56.

[b]ROI x transportation investment.

[c](Necessary revenues ÷ original revenues) - 1.

Table 8-58. PER-TRAILER CONTROL COSTS AS A PERCENT OF PER-TRAILER EXPENSES

	Model Firm			
	1	2	3	4
Operating Expenses/Trailer ($000)[a]	300	206	67.5	53
Annualized Control Costs/Owned Trailer ($000)[b]				
Scenario 1	1.6	1.6	0.8	0.8
Scenario 2	2.4	2.4	1.2	1.2
Control Costs/Operating Expenses				
Scenario 1	0.5%	0.8%	1.2%	1.5%
Scenario 2	0.8%	1.1%	1.8%	2.3%

[a]Given in Table 8-54.

[b]Given in Table 8-39. An adjustment to the values in that table was made for model firms 3 and 4 because Table 8-58 deals with all owned trailers, whereas Table 8-39 deals with only those requiring conversions.

The final impact on the wholesale price for gasoline will be minor since the transportation rate is such a small component of the wholesale price (2.3% = \$.004/liter ÷ \$0.17/liter).[84] Cost pass-through will necessitate a range of price increases of 0.01 percent (0.023 x 0.006) to 0.04 percent (0.023 x 0.018) for Scenario 1. For Scenario 2 the price increases range from 0.03 percent (0.023 x 0.012) to 0.07 percent (0.023 x 0.030).

8.4.2.2.3 Debt service coverage analysis. Table 8-59 presents the results of the debt service coverage analysis. The decline in the debt service coverage ratio ranges between 4.2 and 14.3 percent for Scenario 1 and 8.3 to 19.0 percent for Scenario 2. In absolute terms, the debt service coverage ratio is approximately 2.0 for all the model firms under the baseline case. Under Scenarios 1 and 2, the ratio drops minimally to the 1.7 to 1.9 range for model firms 2, 3, and 4. This decrease does represent a slight increase in lender risk, but not enough to affect the capital financing capability of the model firms.

8.4.2.3 Conclusion. The extent to which the regulatory alternatives would have a potentially significant economic impact on the independent tank truck industry varies by hypothetical firm size. Under both Scenario 1 (add-on of vapor recovery equipment only) and Scenario 2 (vapor recovery plus conversion from top loading to bottom loading), the smallest firm size would not be significantly affected by the regulatory alternatives. Return-on-transportation investment rates would drop by, at most, 2.0 percentage points if control costs were fully absorbed. If the control costs were fully passed through to the consumer in the form of higher prices, prices would increase by a maximum of 0.01 to 0.03 percent.

In the absence of some control cost pass-through, the viability of the three largest firms could become threatened with the imposition of any of the regulatory alternatives, largely because return-on-transportation investment rates could drop by 1.4 to 4.5 percentage points, representing a relative decrease of 21 to 56 percent in ROTI. However, assuming full cost pass-through, maximum percentage price increases would remain low, approximately 0.02 to 0.07 percent, and the firms' ability to meet debt service costs would, as for the smaller plants, remain healthy.

Table 8-59. DEBT SERVICE COVERAGE ANALYSIS
(Current Maturity Long-Term Debt)

($000)

	MODEL FIRM			
	1	2	3	4
Baseline				
Net Income After Taxes	23.00	31.95	43.80	129.40
Depreciation[a]	35.30	82.10	115.30	303.80
Cash Flow[b]	58.30	114.05	159.10	433.20
CMLTD[c]	24.50	56.60	79.50	209.60
Debt Service Coverage[d]	2.4	2.0	2.0	2.1
Scenario 1				
Net Income After Taxes	21.40	26.30	31.75	89.25
Depreciation[e]	36.30	85.50	122.50	327.80
Cash Flow[b]	57.70	111.80	154.25	417.05
CMLTD[c]	25.00	59.00	84.50	226.20
Debt Service Coverage[d]	2.3	1.9	1.8	1.8
Scenario 2				
Net Income After Taxes	20.65	23.65	26.05	70.25
Depreciation[e]	37.90	91.10	134.50	367.80
Cash Flow[b]	58.55	114.75	160.55	438.05
CMLTD[c]	26.20	62.90	92.80	253.80
Debt Service Coverage[d]	2.2	1.8	1.7	1.7

[a]Gross revenues x .054 (depreciation/revenue ratio).

[b]Net income after taxes + depreciation.

[c]Depreciation x .69 (current maturity long-term debt/depreciation ratio).

[d]Cash flow ÷ CMLTD.

[e](0.20 x control capital costs) + baseline depreciation (0.20 assumes a 5 year equipment life consistent with Section 8.4.1.2.1).

This analysis represents a worst case, since impacts were estimated for two opposite and extreme situations, full cost absorption and full cost pass-through. The potential impacts on the three larger model firms under the full absorption assumption are severe enough, in terms of ROTI, that these firms would be expected to take some action to avoid them altogether or to mitigate them. There are four possible avenues open to them.

1. Avoid loading at bulk terminals subject to the standards.
2. Equip only a portion of the trailer fleet to load at affected terminals.
3. Purchase new trailers equipped to load at affected terminals only as needed to replace trailers being taken out of service.
4. Mitigate impacts on ROTI by passing through a portion of control costs.

The first option would be a viable response to the regulatory alternatives only where sufficient gasoline-hauling business could be obtained from other terminals which were not affected facilities. If widely practiced in a region, affected facilities might have to purchase additional trailers themselves to serve their customers.

The second option has already been incorporated in the analysis (Section 8.2.5.3). It would provide a means of reducing the total control cost incurred by a given firm and would be possible to the extent that there was a mixture of affected and unaffected facilities in the firm's operating area.

The third option, which can be combined with the first or the second, would allow a firm to postpone the full impact of control costs and to reduce them somewhat by avoiding the additional expense of retrofit.

The fourth option, which could also be combined with any of the others, would be viable in areas where competition from smaller firms, firms not dealing with affected facilities, or firms already operating tank trucks compatible with affected terminals, did not restrict the firm's freedom to raise prices. The price impact at the gasoline pump would not be highly significant relative to increases resulting from crude oil price rises.

The most likely response of one of the larger firms would be a combination of all of the options. Consequently, the regulatory alternatives can be expected to cause a modest (less than 0.05 percent) increase in retail gasoline prices and to bring about some changes in tank truck firm service areas and in the arrangements made by affected facilities to get their gasoline to the consumer. None of these impacts is expected to be serious. Additionally, no firm closures are expected under any regulatory alternative except those occurring from natural attrition.

8.5 POTENTIAL SOCIOECONOMIC AND INFLATIONARY IMPACTS

The purpose of Section 8.5 is to address the tests of macroeconomic impact contained in Executive Order 12044 and, more generally, to assess any other significant macroeconomic and social impacts that may result from the regulatory alternatives.

The economic impact assessment is concerned only with the costs or negative impacts of the alternatives. The regulation would also result in benefits or positive impacts such as cleaner air and possible improved health for the population, potential increases in worker productivity, and increased business for the pollution control equipment manufacturing industry. However, these potential benefits will not be discussed here.

Executive Order 12044 provides several criteria for a determination of major economic impact. Those criteria are:

1. Additional annualized costs of control that, including capital charges (interest and depreciation), will total $100 million (i) within any one of the first five years of implementation (normally in the fifth year for NSPS), or (ii) if applicable, within any calendar year up to the date by which the law requires attainment of the relevant pollution standard.
2. Total additional cost of production of any major industry product or service will exceed 5 percent of the selling price of the product.
3. Net national energy consumption will increase by the equivalent of 25,000 barrels of oil per day (50×10^{12} Btu or 5×10^{9} kWh per year).

4. Additional annual demand will increase or annual supply will decrease by more than 3 percent for any of the following materials by the attainment date, if applicable, or within five years of implementation: plate steel, tubular steel, stainless steel, scrap steel, aluminum, copper, manganese, magnesium, zinc, ethylene, ethylene glycol, liquified petroleum gases, ammonia, urea, plastics, synthetic rubber, or pulp.

8.5.1 Additional Control Costs

As described in Section 8.1.2.3, five new terminals are expected to be constructed during the 1980-85 period, and approximately 50 more will become affected through modification or reconstruction. Thirty of the latter are likely to be located in attainment areas and 20 in non-attainment areas. Only eight of the 20 affected terminals in non-attainment areas are expected to require control unit replacement or add-on equipment. The remaining 12 terminals will not incur additional control costs. Thus, costs are presented below for 43 of the 55 new and existing bulk terminals expected to be affected in the first five years. Assuming, as a worst case, that each affected terminal experiences the highest net annualized cost appropriate to it in Section 8.2 (Tables 8-17 through 8-19 and 8-29 through 8-36), the total additional annual cost of control in the fifth year (in mid-1979 dollars) is:

1	950,000 l/day new terminal	$ 55,800
2	1,900,000 l/day new terminals	127,400
2	3,800,000 l/day new terminals	168,400
25	Top loaded existing 950,000 l/day terminals in attainment areas	3,900,000
5	Bottom loated existing 950,000 l/day terminals in attainment areas	281,500
8	Existing 950,000 l/day terminals replace control units in non-atainment areas	717,600
	Total net annualized cost	$ 5,250,700

The above costs represent the maximum costs to terminals incurred under any of the alternatives in the fifth year. The 950,000 liter/day terminal was selected as representative of the existing terminals which would be affected under the alternatives; thus, costs are calculated for this size terminal. It can be seen from the total that the additional annualized costs of control, even under the most costly alternatives considered, would be well within the criterion level of $100 million. The highest net annualized cost to the for-hire tank truck industry would occur under Alternatives II and IV, at $0.7 million in the fifth year of the standard.

8.5.2 Excessive Additional Production Costs

The cost pass-through analyses for both new and existing facilities (Sections 8.4.2.2.1 and 8.4.1.3.2) show that retail gasoline price increases of even 1 percent are not likely to result from any of the regulatory alternatives. No major economic impact is indicated.

8.5.3 Net National Energy Consumption

Assuming the same mix of plants as in Section 8.5.1, and referring to energy consumption and recovery rates shown for control equipment in Table 7-3 of Chapter 7, net energy impacts are, in the worst case (i.e., using thermal oxidation which consumes some energy and recovers none):

		Btu/yr x 10^6
1	950,000 l/day new terminal	198.1
2	1,900,000 l/day new terminals	779.1
2	3,800,000 l/day new terminals	1,452.6
38	950,000 l/day existing terminals	7,526.9
	Total net energy consumption	9,956.7 x 10^6 Btu/yr

This is far below the 50 x 10^{12} Btu criterion for major impact. As with the costs in Section 8.5.1, the 950,000 liter/day terminal was selected as representative of existing affected terminals, and no incremental energy impacts were attributed to 12 of the affected terminals in non-attainment areas.

If each plant selected the control unit with the best energy recovery capability, a large net energy savings would result:

		Btu/yr x 10^9
1	950,000 l/day terminal	12.6
2	1,900,000 l/day new terminals	51.2
2	3,800,000 l/day new terminals	103.7
38	950,000 l/day existing terminals	479.2
	Total net energy recovery	646.7 x 10^9 Btu/yr

No significant energy impact is expected due to the controls on the for-hire tank truck industry.

8.5.4 Demand for Scarce Materials

None of the regulatory alternatives would result in a perceptible change in demand for or supply of the materials listed, since they are not used in large amounts in controlling VOC vapor emissions from bulk gasoline terminals. Additionally, controls on the for-hire tank truck industry would have no significant impact on the demand for scarce materials.

8.5.5 Other Impacts

The alternatives would not further curtail a small businessman's opportunities to enter the gasoline terminal industry; they are already limited by the lower returns from smaller facilities in the existing situation. There is some concern for an existing small terminal's ability to continue in operation if it becomes an affected facility. Low ROIs may make closure a more attractive alternative. However, few existing facilities will find themselves in this position. Employment impacts are therefore negligible, as are adverse effects on regional economies.

Foreign trade and balance of payments should not be influenced by the proposed standards, since little gasoline is purchased from overseas refineries.

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APPENDIX A

EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

APPENDIX A - EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

In early 1978, the Argonne National Laboratory prepared a list of 156 major source categories and ranked them in order of priority for NSPS development. The method used to rank the source categories was based on emissions, public health/welfare, and source mobility, which were criteria set forth by the Congress in the 1977 Clean Air Act Amendments. The Petroleum Transportation and Marketing category was ranked twenty-third in priority on a list of 59 source categories selected by EPA.

The standards development began when a series of EPA-sponsored emission tests was initiated in 1973. These efforts were initially directed toward the regulation of VOC emissions from bulk terminals. A Control Techniques Guideline for VOC control at terminals was published in October 1977. A study of benzene emissions from the gasoline marketing industry was then initiated with the intention of developing a national hazardous pollutant standard. The information was presented before the National Air Pollution Control Techniques Advisory Committee (NAPCTAC), and the issue is currently under review with no set schedule for completion. NSPS development for the bulk terminal subcategory was started in November 1978.

Information was gathered through visits to bulk terminals, Section 114 letters to oil companies, and telephone contacts to industry representatives, consultants, and equipment manufacturers. In addition, a literature survey, including examination of test results, was conducted. The major events relating to this effort are in the chronology below.

A.1 CHRONOLOGY

The chronology to follow lists the significant events which have occurred in the development of the background information document supporting a New Source Performance Standard for Bulk Gasoline Terminals. Appendix C contains summaries of the numbered emission tests shown in the chronology.

Date	Activity
11/18/73 to 5/2/74	Terminal Emission Test No. 4
12/11-12/74	Terminal Emission Test No. 14
12/17-19/74	Terminal Emission Test No. 8
9/20-22/76	Terminal Emission Test No. 9
9/23-25/76	Terminal Emission Test No. 15
11/1/76 to 6/1/77	Section 114 letters sent to oil companies regarding specific terminals
11/10-12/76	Terminal Emission Test No. 10
4/14/77	Meeting with Texaco in Durham, North Carolina
5/25-27/77	Terminal Emission Test No. 1
6/8/77	EPA listing of benzene as a hazardous pollutant under Section 112 of the Clean Air Act
7/7/77	Meeting with API, Union, Amoco, Texaco, Citgo, and Arco in Durham, North Carolina
7/27-29/77	Tank truck emission testing in Aurora, Colorado
10/77	Terminal Control Techniques Guideline issued (Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals. EPA Publication No. EPA-450/2-77-026)
1/10-12/78	Terminal Emission Test No. 6
1/25-27/78	Terminal Emission Test No. 5
2/1,2/78 and 3/6,7/78	Terminal Emission Test No. 20
2/20,21/78 and 3/8,9/78	Terminal Emission Test No. 16
2/23,24,27/78	Terminal Emission Test No. 7

Date	Activity
3/1-3/78	Terminal Emission Test No. 2
4/11-13/78	Terminal Emission Test No. 22
5/2-4/78	Terminal Emission Test No. 17
6/12-17/78	Tank truck testing at Chevron terminal in Los Angeles, California
6/19-23/78	Observed top loading systems at four terminals in Los Angeles, California
6/19-23/78	Tank truck testing at Shell terminal in Los Angeles, California
7/78	Mail out draft Standard Support Environmental Impact Statement for Control of Benzene from the Gasoline Marketing Industry, preamble, and regulation to industry and environmental groups
8/2-4/78	Terminal Emission Test No. 18
8/16-18/78	Terminal Emission Test No. 21
8/22/78	NAPCTAC meeting to review draft standard package mailed out on 7/78
8/22-24/78	Terminal Emission Test No. 11
8/31/78	Proposal of source category priority list in Federal Register
9/12/78	Meeting with HydroTech Engineering, Inc. in Tulsa, Oklahoma
9/19-21/78	Terminal Emission Test No. 19
9/26-28/78	Terminal Emission Test No. 12
9/27/78	Meeting with Fruehauf Corp. in Omaha, Nebraska
10/6/78	Meeting with HydroTech Engineering, Inc. in Durham, North Carolina
10/10-12/78	Terminal Emission Test No. 13
10/13/78	Meeting with Edwards Engineering Corp. in Durham, North Carolina

Date	Activity
10/24-26/78	Terminal Emission Test No. 3
11/78	Start of NSPS development for bulk gasoline terminals
12/78	Tank Truck Control Techniques Guideline issued (Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems. EPA Publication No. EPA-450/2-78-051)
4/23-27/79	Plant visits to six bulk terminals
5/31/79	Section 114 Letter Questionnaire sent to oil companies and specific terminals
6/18/79	Attended meeting with oil companies, consultants, and equipment manufacturers in El Segundo, California
6/26/79	Presentation on VOC controls for the gasoline marketing industry by Jim Durham, EPA, before a meeting of the National Tank Truck Carriers in Boston, Massachusetts
8/21/79	Final rule on source category priority list in Federal Register, Vol. 44, No. 163
10/26/79	Mailout of draft NSPS Background Information Document (Chapters 3-6, Appendix C) for comments from industry and environmental groups
5/5/80	Mailout of draft BID, Preamble, and Regulation to industry, environmental groups, and members of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC)
6/5/80	NAPCTAC meeting in Raleigh, North Carolina, to review the draft NSPS standard for bulk gasoline terminals

Date	Activity
6/5/80	Meeting with SOHIO in Durham, North Carolina
7/22/80	Meeting with Emco Wheaton, Inc., in Durham, North Carolina
7/28/80 to 8/1/80	Plant visits to ten bulk terminals (continuous monitoring testing site survey)
8/4-5/80	Meeting with SOHIO in Cleveland, Ohio

APPENDIX B

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

APPENDIX B - INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

This appendix consists of a reference system which is cross-indexed with the October 21, 1974, Federal Register (39 FR 37419) containing the Agency guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document which contain data and information germane to any portion of the Federal Register guidelines.

APPENDIX B

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document (BID)
1. Background and Description of Regulatory Action	
Summary of the regulatory alternatives	The regulatory alternatives are summarized in Chapter 1, Section 1.1.
Statutory basis for proposing standards	The statutory basis for proposing standards is given in Chapter 2.
Facility affected	A description of the facilities to be affected is given in Chapter 6, Section 6.2.2.
Process affected	A description of the processes to be affected are given in Chapter 3, Section 3.2.
Availability of control technology	Information on the availability of control technology is given in Chapter 4.
Existing regulations at State or local level	A discussion of existing regulations on the industry to be affected by the regulatory action is included in Chapter 3, Section 3.3.
2. Environmental Impact of Regulatory Alternatives	
Air Pollution	The air pollution impacts of the regulatory alternatives are discussed in Chapter 7, Section 7.1.
Water Pollution	The impacts of the regulatory alternatives on water pollution are discussed in Chapter 7, Section 7.2.

(Continued)

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS (Concluded)

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document (BID)
Solid waste disposal	The impacts of the regulatory alternatives on solid waste disposal are discussed in Chapter 7, Section 7.3.
Energy consumption	The impacts of the regulatory alternatives on energy consumption are discussed in Chapter 7, Section 7.4.
3. Economic Impact of Regulatory Alternatives	
Costs	The cost impacts of the regulatory alternatives are discussed in Chapter 8, Section 8.2.
Economic analysis	Economic analyses of the regulatory alternatives are contained in Chapter 8, Sections 8.4 and 8.5.

APPENDIX C

EMISSION SOURCE TEST DATA

APPENDIX C - EMISSION SOURCE TEST DATA

C.1 SUMMARY OF TEST ACTIVITY

C.1.1 General

The primary means of determining the field performance of various types of vapor processing units is through an examination of test data from actual emission tests at bulk terminals. In order to normalize the test results to account for varying loading volumes, all calculated parameters are weighted in proportion to the gasoline volumes loaded. In addition, actual VOC emission levels from the processors as measured in these tests are adjusted to account for the calculated leakage rates from tank trucks. Section C.2 explains the data further.

C.1.2 EPA-Conducted Tests

EPA conducted 22 emission tests for VOC emissions at bulk gasoline terminals throughout the United States between 1973 and 1978. Tests were performed on the six types of vapor processors whose principles of operation were described in Chapter 4. These tests followed, with occasional minor exceptions, the procedure developed by EPA-OAQPS as described by the CTG for terminals.[1] Section C.3 contains summaries of each of the tests. Test results are presented in Table C-1.

C.1.3 Other Vapor Processor Tests

The San Francisco Bay Area Air Quality Management District performed VOC emission tests on 26 vapor recovery installations in California between 1976 and 1979. Twenty-five of the units tested were compression-absorption type units, and one was a refrigeration (REF) type unit. The compression-absorption unit is similar to the CRA unit, except that the refrigeration section is not included. These units were produced primarily for use in California and are no longer being marketed. Details concerning the test procedure and conditions were not available to the authors of this report.

Table C-1. WEIGHTED DAILY AVERAGES[a] OF CALCULATED EMISSION TEST PARAMETERS

Test Number	Test Date	Type of Unit[b]	$(\overline{V/L})_r$	$(\overline{V/L})_p$	F factor	$(M/L)_r$ (mg/liter)	C_r	$(M/L)_e$ (mg/liter)	C_e	$(M/L)_t$ (mg/liter)	$(M/L)_e*$ (mg/liter)	E_p (%)
1	5/25/77	CA	0.693	1.0[c]	1.44	703	56.2	64.2	6.0	374	92.6	90.9
	5/26/77		0.641	1.0[c]	1.56	666	60.4	5.4	2.2	378	8.5	99.2
	5/27/77		0.685	1.0[c]	1.46	613	48.8	2.7	0.14	285	3.9	99.6
2	3/1/78	CA[d]	0.645	1.0[c]	1.55	240	20.5	1.2	0.18	133	1.8	99.5
	3/2/78		0.753	1.0[c]	1.33	219	13.5	2.1	0.30	74.4	2.8	99.0
	3/3/78		0.643	1.0[c]	1.56	225	15.4	2.5	0.33	129	3.9	98.9
3	10/24/78	CA	1.05	1.07	1.02	790	45.0	10.8	0.83	26.6	11.0	98.6
	10/25/78		1.06	1.07	1.01	806	40.1	9.6	0.83	17.7	9.7	98.8
	10/26/78		1.03	0.957	1.0[e]	853	43.8	63.4	3.7	63.4	63.4	92.6
4	11/73[f]	TO[d]	0.741	1.0[c]	1.35	500.0	29.2[g]	1.0	0.002[g]	176.0	1.4	99.8
5	1/25/78	TO	0.725	1.0[c]	1.38	577.3	36.9	77.6	0.06	296.9	107.1	86.6
	1/26/78		0.775	1.0[c]	1.29	579.0	39.6	36.7	0.03	204.6	47.3	93.7
	1/27/78		0.839	1.0[c]	1.19	370.4	23.1	32.8	0.02	103.1	39.0	91.1
	1/30/78		0.846	1.0[c]	1.18	405.9	24.1	24.2	0.02	97.3	28.6	94.0
6	1/10/78	TO	0.866	1.0[c]	1.15	383.0	33.9	21.4	0.004	78.9	24.7	93.6
	1/11/78		0.799	0.963	1.21	330.1	27.8	22.4	0.005	91.7	27.0	93.2
	1/12/78		0.778	1.0[c]	1.28	411.2	31.1	39.8	0.008	154.9	50.9	90.3
7	2/23/78	TO[d]	0.804	1.0[c]	1.24	290.0	18.6	23.7	1.7	93.3	29.4	90.0
	2/24/78		0.807	1.0[c]	1.24	426.0	27.3	7.5	0.7	109.7	9.3	98.2
	2/27/78		0.781	1.0[c]	1.28	439.0	28.3	10.3	0.8	133.2	13.2	97.7
8	12/17/74	REF	0.758	1.0[c]	1.32	313.6	17.0	33.3	3.4	133.7	44.0	89.4
	12/19/74		0.749	1.03	1.38	354.0	18.8	39.4	3.6	173.9	54.4	88.9

Table C-1. WEIGHTED DAILY AVERAGES[a] OF CALCULATED EMISSION TEST PARAMETERS (Continued)

Test Number	Test Date	Type of Unit[b]	$(\overline{V/L})_r$	$(\overline{V/L})_p$	F factor	$(M/L)_r$ (mg/liter)	C_r	$(M/L)_e$ (mg/liter)	C_e	$(M/L)_t$ (mg/liter)	$(M/L)_e^*$ (mg/liter)	E_p (%)
	9/20/76		0.751	1.05	1.40	505.2	35.6	51.6	4.8	253.7	72.2	89.8
9	9/21/76	REF	0.904	1.0[c]	1.11	494.0	50.6	52.3	4.7	106.6	58.1	89.4
	9/22/76		0.809	0.843	1.04	554.5	50.9	29.9	3.6	52.1	31.1	94.6
	11/10/76		0.825	1.04	1.26	369.0	23.7	49.1	3.6	172.5	61.9	86.7
10	11/11/76	REF	0.987	1.02	1.03	340.8	17.8	57.1	3.3	67.3	58.8	83.2
	11/12/76		0.900	1.03	1.14	237.0	13.3	54.2	3.3	87.4	61.8	77.1
	8/22/78		1.55	1.39	1.0[e]	2367	NA[h]	1318	56.8	1318	1318	44.3
11	8/23/78	REF	1.62	1.63	1.00	2290	82.2	840.8	29.8	840.8	840.8	63.3
	8/24/78		1.62	1.62	1.00	2101	75.2	794.2	38.4	794.2	794.2	62.2
	9/26/78		0.808	0.915	1.13	573.0	31.7	67.2	5.3	141.7	75.9	88.3
12	9/27/78	REF	0.963	0.953	1.00	735.5	30.0	102.6	6.2	102.6	102.6	86.1
	9/28/78		0.964	1.06	1.10	723.7	39.8	61.9	4.9	134.3	68.1	90.6
	10/10/78		0.565	1.0[c]	1.77	558.9	47.9	i	3.2	i	i	i
13	10/11/78	REF	0.591	1.0[c]	1.69	728.9	52.4	i	3.1	i	i	i
	10/12/78		0.629	1.0[c]	1.59	602.3	51.8	i	3.5	i	i	i
	12/11/74		0.422	1.0	2.37	80.3	18.2	31.0	4.7	141.0	73.5	61.4
14	12/12/74	CRA[d]	0.469	0.847	1.81	135.5	21.5	31.6	4.3	141.4	57.2	76.7
	9/23/77		0.731	1.06	1.45	628.6	48.8	30.7	3.9	313.6	44.5	95.1
15	9/24/77	CRA[d]	0.681	1.05	1.54	339.6	38.9	30.5	3.4	213.9	47.0	91.0
	9/25/77		0.734	0.950	1.29	NA[h]	NA[h]	NA[h]	3.2	NA[h]	NA[h]	NA[h]
	2/20/78		0.683	1.0[c]	1.46	375	29.3	NA	5.3	NA	NA	NA
16	2/21/78	CRA[d]	0.696	1.0[c]	1.44	372	31.2	61.2	6.1	224.9	88.1	83.5
	3/8/78		NA[h]	1.0[c]	NA[h]	NA[h]	28.7	59.5	5.3	NA[h]	NA[h]	NA[h]
	3/9/78		NA[h]	1.0[c]	NA[h]	NA[h]	27.1	57.2	5.3	NA[h]	NA[h]	NA[h]

Table C-1. WEIGHTED DAILY AVERAGES[a] OF CALCULATED EMISSION TEST PARAMETERS (Concluded)

Test Number	Test Date	Type of Unit[b]	$(\overline{V/L})_r$	$(\overline{V/L})_p$	F factor	$(M/L)_r$ (mg/liter)	C_r	$(M/L)_e$ (mg/liter)	C_e	$(M/L)_t$ (mg/liter)	$(M/L)_e^*$ (mg/liter)	E_p (%)
17	5/2/78	CRA[d]	0.521	1.0[c]	1.92	232.5	17.0	40.9	2.5	254.8	78.5	82.4
	5/3/78		0.775	1.0[c]	1.29	462.4	30.6	45.1	2.5	179.2	58.2	90.2
	5/4/78		0.691	1.0[c]	1.45	227.2	23.2	35.9	2.5	138.1	52.1	84.2
18	8/2/78	CRA[d]	0.724	0.936	1.29	509.9	35.5	32.2	3.6	180.1	41.5	93.7
	8/3/78		0.887	1.34	1.51	642.0	37.6	43.1	3.8	370.5	65.1	93.3
	8/4/78		0.904	1.11	1.23	821.7	45.0	43.0	4.1	232.0	52.9	94.8
19	9/21/78	CRA[d]	0.992	1.05	1.06	1047.0	56.6	85.9	3.6	149.3	91.0	91.8
20	3/6/78	CRC[d]	0.850	1.0[c]	1.18	372.5	22.1	41.0	3.4	108.1	48.4	89.0
	3/7/78		0.794	1.0[c]	1.26	523.1	38.4	44.4	3.8	180.4	55.9	91.5
21	8/16/78	CRC[d]	0.842	1.0[c]	1.19	1054	64.8	i	11.9	i	i	i
	8/17/78		0.924	0.987	1.07	1281	75.6	i	12.9	i	i	i
	8/18/78		0.904	1.07	1.18	1136	59.7	i	13.6	i	i	i
22	4/11/78	LOA	0.748	1.0[c]	1.34	375.1	29.3	97.0	9.2	224.5	130.0	74.1
	4/12/78		0.725	1.0[c]	1.38	375.1	29.0	52.9	5.3	195.4	73.0	85.9
	4/13/78		0.728	1.0[c]	1.37	372.5	28.3	86.7	9.2	224.5	118.8	76.7

NOTES — TABLE C-1

[a]Parameters are weighted in proportion to the amount of gasoline loaded during each run.

[b]CA - Carbon Adsorption
TO - Thermal Oxidation
REF - Refrigeration
CRA - Compression-Refrigeration-Absorption
CRC - Compression-Refrigeration-Condensation
LOA - Lean Oil Absorption

[c]Value assumed to be 1.0 when no truck leakage measurements available.

[d]Vapor holder used.

[e]Assumed value since calculated F factor is less than unity.

[f]Testing performed for nearly six months; no daily averages reported (see Section C.2).

[g]Volume percent as methane.

[h]Parameter not calculated due to lack of measured test data.

[i]Not calculated due to unknown quantity of leakage from vapor collection system.

DEFINITIONS

1. $\overline{(V/L)}_r$ = Volume of air-VOC mixture returned per volume of liquid dispensed.
2. $\overline{(V/L)}_p$ = Potential vapor/liquid volume ratio, assuming no leakage losses.
3. F factor = $\overline{(V/L)}_p \div \overline{(V/L)}_r$, an adjustment factor to account for leakage.
4. $\overline{(M/L)}_r$ = VOC mass returned per volume of liquid dispensed (uncontrolled emissions).
5. C_r = Volume percent of VOC in returned mixture (volume percent as propane).
6. $\overline{(M/L)}_e$ = VOC mass exhausted from the processor per volume of liquid dispensed (controlled emissions).
7. C_e = Volume percent of VOC in exhausted mixture (volume percent as propane).
8. $\overline{(M/L)}_t$ = Total system VOC mass emissions, including leakage from tank trucks.
9. $\overline{(M/L)}_e^*$ = F x $(M/L)_e$, adjusted mass emissions.
10. E_p = Processing unit VOC control efficiency.

An adjustment factor of 1.10 to account for tank truck leakage was assumed for all tests. Tank truck leak-tight regulations were in effect during these tests. The factor was developed from over 100 tank truck loadings in an area having similar regulations.[2]

The average processor VOC emission level for all 25 tests involving compression-absorption units was 75.5 milligrams per liter (0.286 gram per gallon) of gasoline loaded. Adjusted emissions averaged 83.1 milligrams per liter (mg/l), or 0.315 gram per gallon (gm/gal). If the three highest processor emission values (which averaged 205 mg/l or 0.776 gm/gal) are deleted from the calculations, average emissions were 57.9 mg/l (0.219 gm/gal), with adjusted emissions of 63.7 mg/l (0.241 gm/gal). Processor emissions from the REF unit were 13.0 mg/l (0.049 gm/gal), with adjusted emissions of 14.3 mg/l (0.054 gm/gal). Data from these tests are summarized in Table C-2.

The results of four tests on vapor processing systems were received from the California Air Resources Board.[3,4,5,6] Three of these tests were performed on refrigeration units, and one was performed on a carbon adsorption unit. The VOC emission rates for the refrigeration tests were 5 mg/liter, 36 mg/liter, and 48 mg/liter, for an average emission rate of 30 mg/liter. The results from the carbon adsorption tests did not give an exact value for the VOC emissions, but only reported that the emission rate was less than 12 mg/liter.

C.1.4 Tank Truck Leakage Tests

EPA conducted vapor leak tests on 27 truck tanks in California during the month of June 1978.[2,7] These tank trucks were under a requirement of the California Air Resources Board (CARB) to undergo an annual leak tightness test. Both top and bottom loading terminals were selected for inclusion in the test program. Trucks were selected to provide a representative cross-section of tank age and type of vapor-containing equipment. Tests were conducted on the truck tanks before any maintenance was performed. This was done to establish the truck leakage rate since the last certification. Testing included a volume leakage test followed by a specified CARB pressure and vacuum test.

Table C-2. RESULTS OF VAPOR RECOVERY SYSTEM TESTS PERFORMED BY SAN FRANCISCO BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Test	Test Date	Control Unit	Volume of Gasoline Loaded (10^3 Liters)	VOC Emissions From Processor (mg/liter)	Adjusted[a] Processor Emissions (mg/liter)	Control Unit Efficiency (Percent)
A	06/23/76	COM[b]	1,830	86	95	89.2
B	03/24/77	COM	1,190	56	62	90.7
C	03/31/77	COM	460	37	41	90.9
D	04/19/77	COM	470	332	365	59.4
E	05/19/77	REF[c]	1,040	13	14	98.1
F	08/03/77	COM	270	43	47	95.3
G	10/12/77	COM	210	46	51	92.1
H	10/21/77	COM	470	107	118	84.5
I	11/09/77	COM	1,670	56	62	93.1
J	11/16/77	COM	310	46	51	93.7
K	12/06/77	COM	250	175	193	81.1
L	01/26/78	COM	540	59	65	92.7
M	02/23/78	COM	1,040	56	62	93.8

[a]Adjusted for tank truck leakage. Adjustment factor of 1.1 used based upon tank truck testing in an area with similar vapor-tight regulations.

[b]COM = Compression-Absorption.

[c]REF = Refrigeration.

Table C-2. RESULTS OF VAPOR RECOVERY SYSTEM TESTS PERFORMED BY SAN FRANCISCO BAY AREA AIR QUALITY MANAGEMENT DISTRICT (Concluded)

Test	Test Date	Control Unit	Volume of Gasoline Loaded (10^3 Liters)	VOC Emissions From Processor (mg/liter)	Adjusted[a] Processor Emissions (mg/liter)	Control Unit Efficiency (Percent)
N	03/01/78	COM	780	60	66	93.8
O	04/26.78	COM	560	59	65	92.3
P	05/02/78	COM	970	71	78	89.0
Q	06/09/78	COM	470	38	42	95.9
R	06/14/78	COM	990	78	86	91.7
S	06/15/78	COM	2,860	75	83	90.5
T	06/27/78	COM	700	58	64	93.5
U	07/20/78	COM	1,050	77	85	90.5
V	09/08/78	COM	790	46	51	94.5
W	09/20/78	COM	950	64	70	91.7
X	10/07/78	COM	200	59	65	92.9
Y	12/28/78	COM	200	47	52	93.5
Z	04/18/79	COM	1,780	56	62	---[d]

[a]Adjusted for tank truck leakage. Adjustment factor of 1.1 used based upon tank truck testing in an area with similar vapor-tight regulations.

[b]COM = Compression-Absorption.

[c]REF = Refrigeration.

[d]No data.

Both of these tests are similar in that both tests quantitatively measured gas volume loss from tanks due to leakage.

Four of the tanks tested had maintained the ability to pass the leak tests. The time since the last certification date on the tanks ranged from four months to four days. Of the tanks that failed, the time frame ranged from one year to two weeks (see Table C-3). Leaks occurred primarily at dome lids, base rings, and P-V vents. The leakage rates for the trucks tested varied considerably. High leakage rates were found within 20 days of certification in several cases, while one case indicated a relatively low leakage rate at the end of one year. Table C-4 summarizes the results of the tank testing. This table includes data for those tanks tested before maintenance was performed. Several of the 27 trucks included in the study did not have a test performed prior to maintenance because of time constraints. The average leakage rate for those tanks included in Table C-4 was approximately 10 percent, meaning that approximately 10 percent of the air-vapor mixture exhausted from a regulated gasoline tank truck during product loading would leak to the atmosphere without reaching the vapor processor.

The bulk terminal tests described in Section C.1.2 were performed in areas where no tank truck leak tightness regulations were in effect. The average leakage from tanks in these tests was determined to be 30 percent.

C.2 TEST RESULTS AND CALCULATIONS

C.2.1 Factors Affecting Test Results

There are many factors which can contribute to the variability of results among tests on a particular type of vapor processing system.

The efficiency of most processors depends to some degree on the VOC concentration in the incoming air-vapor mixture; generally, a higher inlet concentration leads to a higher collection efficiency. This trend is difficult to discern in the data summary because of the other factors involved; for example, in some cases the unit was not operating properly so that the efficiency was lower than expected. The runs in which a tank truck was vapor-balanced (Stage I service

Table C-3. TANK TIGHTNESS HISTORY[2]

Tank Identification Number	Last Certification Date[a]	Field Test Date	Pass/Fail[e]	Type of Loading
63806	2/24/78	6/23/78	F	Top
53306	2/24/78	6/23/78	F	Top
63767	2/09/78	6/20/78	F	Top
53256	2/09/78	6/20/78	P	Top
63766	2/08/78	6/20/78	F[c]	Top
53345	2/08/78	6/20/78	F[c]	Top
63765	2/07/78	6/19/78	F	Top
63765[d]	6/19/78	6/23/78	P	Top
53304	2/07/78	6/23/78	P	Top
63804	2/16/78	6/21/78	F	Top
53307	2/16/78	6/22/78	F	Top
63803	2/10/78	6/21/78	F	Top
53297	2/10/78	6/21/78	F	Top
63805	2/28/78	6/22/78	F	Top
53305	2/28/78	6/22/78	F[c]	Top
67-282	5/18/78	6/14/78	F	Bottom
67-392	5/23/78	6/13/78	F	Bottom
67-475	5/24/78	6/15/78	P	Bottom
68-795	5/03/78	6/14/78	F	Bottom
68-795[b]	5/03/78	6/14/78	F	Bottom
68-597	6/13/77	6/13/78	F	Bottom
68-597[b]	6/13/77	6/13/78	F	Bottom
68-275	6/28/77	6/15/78	F[c]	Bottom
68-275[b]	6/28/77	6/15/78	F[c]	Bottom
68-977	5/03/78	6/16/78	F[c]	Bottom
68-977[b]	5/03/78	6/16/78	F[c]	Bottom
67-775	No data	6/12/78	F	Bottom

[a]Passed CARB Certification Test.

[b]Trailer of Truck/Trailer Unit.

[c]Tanks not maintained to pass conditions after field tests, all other tanks maintained to pass conditions.

[d]Tested twice during the field tests.

[e]Passed or failed field pressure/vacuum test.

Table C-4. RESULTS OF EPA-SPONSORED TANK TRUCK LEAKAGE TESTS[3]

Days Since Certification Test[a]	Tank Truck Vapor Leakage (Percent)[b]
4	0.1
4	0.6
6[c]	2.0
6[c]	2.5
7	2.0
20	16.4
21	0.4
26	22.8
34[c]	1.9
43	2.2
43	13.6
125	10.0
131	1.0
131	2.4
132	22.4
136	16.0
300	35.8
360	3.6
360	12.4
360	26.8

[a]The number of days since the tank last passed a pressure/vacuum test.

[b]Percent of vapors which would be lost due to leakage during tank loading.

[c]Leakage rate from tank loading determined by V/L ratio.

station control) previous to being loaded generally show a somewhat higher average efficiency than non-balanced runs (due to higher VOC concentration in the air-vapor mixture returned to the processor).

A common deviation from the prescribed test procedure involved the use of butane (C_4H_{10}) as the reference hydrocarbon in mass calculations (14 tests). In these cases the values for concentration (as volume percent as butane) were factored by the ratio of the densities of butane and propane. As an example, in Test No. 22,

$$C_r = 21.9\% \text{ (as butane) } \times \frac{68.3 \text{ grams } C_4H_{10}/ft^3}{51.8 \text{ grams } C_3H_8/ft^3} = 28.9\% \text{ (as propane).}$$

In one test (Test No. 4), methane was used as the reference hydrocarbon in mass calculations. The values of concentration in this test were not converted to volume percent as propane because of the extremely small exhaust concentrations.

In some cases, the data presented in this document do not match those found in the emission test reports. This occurred because some runs were deleted when the test data were reviewed and recalculated. In these cases the deleted runs were not considered representative of typical operation, or data were not complete. In addition, the criteria for determining when leaks were present in the system were slightly modified. Section C.2.2 discusses calculations involving system leakage.

C.2.2 System Leakage Calculations

When air-vapor mixture leakage occurs at dome covers or vent valves on the tankers during loading, the quantity of VOCs actually recovered is less than that potentially recoverable. The runs during which no leaks were detected by combustible gas detector measurements are separated and the potential volumetric recovery is calculated. This parameter is weighted in proportion to the amount of gasoline loaded during each run and reflects the gas volume-to-liquid volume ratio in a leak-free system. When no combustible gas detector measurements were available, the potential volumetric recovery was assumed equal to 1.0.

The actual calculated volumetric recoveries are variable, and can be less than, equal to, or greater than 1.0. Values less than one can usually be attributed to system leakage, in which some of the air-vapor mixture displaced by loaded gasoline is lost to the atmosphere. Recoveries equal to one represent the ideal case, in which each unit volume of gasoline causes a unit volume of mixture to be returned to the vapor processor. Recoveries which exceed one are due to vapor growth, which depends on temperature and pressure conditions in the tank trucks and the vapor return lines.

For the purposes of these calculations, a leak was defined as occurring whenever a reading on the combustible gas detector exceeded 100 percent of the lower explosive limit.

C.3 SUMMARIES OF EPA-CONDUCTED TESTS

This section of Appendix C summarizes 22 emission tests conducted by EPA at bulk gasoline terminals between November 1973 and October 1978. Results from these tests were the primary source of information in evaluating the various types of vapor processing systems in use at bulk terminals.

The types of systems tested are carbon adsorption (CA), Test Nos. 1 through 3; thermal oxidizer (TO), Test Nos. 4 through 7; refrigeration (REF), Test Nos. 8 through 13; compression-refrigeration-absorption (CRA), Test Nos. 14 through 19; compression-refrigeration-condensation (CRC), Test Nos. 20 and 21; and lean oil absorption (LOA), Test No. 22.

It is suggested that these test summaries, as well as the emission test reports referenced in this section, be consulted in conjunction with the test results presented in Table C-1. The summaries contain descriptions of the facilities tested, as well as information about test conditions which might have influenced the test results. In addition, the reasons for disregarding test results in some test sequences are discussed.

C.3.1 Bulk Terminal Test No. 1

This terminal is a small gasoline loading terminal with a storage capacity of 3,600,000 liters (950,000 gallons) of gasoline and a daily gasoline throughput of 284,000 liters (75,000 gallons). Barges deliver the supply of gasoline to the terminal. Two loading racks employ five bottom loading positions, with vapor recovery lines leading to an activated carbon adsorption (CA) type vapor recovery unit, manufactured by HydroTech Engineering, Inc.

Testing was performed May 25-27, 1977, during 33 tank truck loadings to determine actual VOC emissions, potential VOC emissions, and the vapor recovery efficiency of the system.

VOCs generated during bottom loading of tank trucks at the terminal are collected by a vapor line collection system and routed to the carbon adsorption vapor processor. VOCs broke through the carbon beds on the first two days of testing. Outlet concentrations from the unit were observed during these breakthroughs to be greater than 10 percent propane. The problems causing bed breakthrough of VOCs were found and corrected before the third (final) day of source testing. VOC breakthroughs of the carbon beds were caused by incorrect settings in electrical timer switching of the dual bed system. On the first day of testing it was noted that the same bed was continuously on line to adsorb vapors whenever a truck started loading. This improper setting of the bed switching system caused an overload on one bed. The setting of the bed switching system was corrected midmorning on the second test day, but some breakthrough was noted on the second day while the system was catching up. No VOC breakthrough was noted on the third day. The improper setting was due to the fact that the system was previously adjusted for processing a low volume lean stream and during the test had to be readjusted to operate on a high volume rich stream. Further details are contained in the emission test report.[8] Part of the runs on the second day and all of the runs on the third day were included in the data analysis. VOC emissions from the vapor recovery unit for the runs when it was operating correctly were 2.7 and 5.4 mg/l (0.010 and 0.020 gm/gal) for the second and third days of testing, respectively. Emissions adjusted to account for system leakage were 8.5 and 3.9 mg/l (0.032 and 0.015 gm/gal).

C.3.2 Bulk Terminal Test No. 2

Test No. 2 was performed March 1-3, 1978, at a small bulk terminal with an average daily gasoline throughput of 189,000 liters (50,000 gallons). Gasoline is dispensed from one loading rack containing three bottom-load dispensing arms.

Vapors displaced from tank trucks during loading are routed to a vapor holder (premium gasoline storage tank equipped with lifter roof). When a specified capacity is reached, the control system is manually started and the vapors travel to a HydroTech Engineering carbon adsorption (CA) vapor recovery unit.

During testing, terminal operations were normal and no instrument problems were reported. Daily average VOC emissions from the control unit were 1.2, 2.1, and 2.5 milligrams per liter (0.005, 0.008, and 0.009 gram per gallon) of gasoline loaded. When adjusted for leakage the emissions were 1.8, 2.8, and 3.9 mg/l (0.007, 0.011, and 0.015 gm/gal).

Further details are contained in the emission test report.[9]

C.3.3 Bulk Terminal Test No. 3

This test was conducted at a bulk terminal with an average daily gasoline throughput of approximately 303,000 liters (80,000 gallons). This terminal is the same one described in Test No. 1. At the start of each day, gasoline tank trucks are loaded on a staggered time schedule with half-hour intervals between loadings. Two of the five loading racks at the terminal dispense gasoline and use vapor recovery. Testing was performed on October 24-26, 1978.

Air-vapor mixture displaced during loading is piped to a liquid knockout tank and then passes to a HydroTech Engineering carbon adsorption (CA) type vapor recovery unit. The data collected on October 26 was not considered in evaluating this control technique because twice on that day two trucks were loaded simultaneously, a deviation from design procedure. This was done purposely to determine the effect on the unit's collection efficiency. The collection efficiency on that day was somewhat lower than that on the first two days of testing.

An air-balance analysis was performed on the air-vapor mixture entering and leaving the control unit during the test. The air-balance ratio, a measure of the ratio of the air entering to the air exiting the unit, calculated for the three days of testing was 1.09, 1.01, and 0.99. The overall ratio for the three days was 1.03.

The test method followed the specified procedure except that total VOC concentrations were measured as volume percent as butane. Ten trucks out of the forty tested proved to be vapor-tight. Daily average VOC emissions from the control unit were 10.8, 9.6, and 63.4 milligrams per liter (0.041, 0.036, and 0.240 gram per gallon) for the three days of testing. Adjusted for leakage, the emissions were 11.0, 9.7, and 63.4 mg/l (0.042, 0.037, and 0.240 gm/gal).

Further details are contained in the emission test report.[10]

C.3.4 Bulk Terminal Test No. 4

Test No. 4 was conducted at a bulk terminal with a throughput of approximately 1,100,000 liters (291,000 gallons) per day. The terminal has two bottom-loading racks and one top-loading rack. VOC vapors from tank trucks are vented through flexible connections to a common header venting to a vapor holder and to a thermal oxidizer (TO) control unit, manufactured by the AER Corporation.

Extensive tests on the thermal oxidizer system at this gasoline loading terminal were performed during the period of November 18, 1973, to May 2, 1974. At this terminal VOC vapors from tank truck loading operations are routed to a vapor holder, where they are enriched with propane to ensure they are above the explosive range. The VOC vapors from the vapor holder are then vented to the thermal oxidizer for incineration.

The oxidizer is a simple gas furnace which turns on and operates as needed; however, if it were necessary to shut down the oxidizer during tank truck loadings or if the vapor holder filled beyond its capacity of 283 cubic meters (10,000 cubic feet), or about 8 truck loads, excess vapors would vent to the atmosphere.

Test results indicated that the oxidizer disposed of 99.8 percent of the VOC vapor collected. However, only about 70 percent of the air-vapor mixture displaced from the truck loading reached the oxidizer. Unusually high pressures (39.7 mm of mercury or 21 inches of water) produced in the truck during loading were responsible for the vapor loss through poorly adjusted hatch covers and faulty pressure-vacuum relief valves on the trucks. Also, low vapor transfer and pressure buildup were caused by blockage of the vapor collection line by a column of gasoline. These problems were partially corrected and the overall disposal efficiency of the entire system (from tank truck to control unit) then exceeded 90 percent. VOC emissions to the atmosphere from the thermal oxidizer are estimated to be 1.0 milligram per liter (0.004 gram per gallon) of gasoline loaded into the tank trucks. The emission rate adjusted to account for system leakage was

1.4 mg/l (0.01 gm/gal) of gasoline loaded. Leakage from the trucks was estimated to be 175.0 mg/l. Further details are contained in the emission test report.[11]

C.3.5 Bulk Terminal Test No. 5

Test No. 5 was performed January 25-27 and January 30, 1978, at a bulk terminal whose average gasoline throughput is 757,000 liters per day (200,000 gallons per day). Gasoline is dispensed from four bottom-loading arms at two loading racks. The air-vapor mixture displaced from tank trucks is directed through a vapor collection system to a liquid knockout tank, and then to a thermal oxidizer (TO) type vapor control unit, manufactured by National Airoil Burner Company. An interlock system shuts down the loading activity if the TO unit should malfunction.

No problems with the control unit or test instrumentation were reported during testing. All VOC concentrations were reported as volume percent as butane. Daily average VOC emissions from the control unit were 77.6, 36.7, 32.8, and 24.2 milligrams per liter (0.294, 0.139, 0.124, and 0.092 gram per gallon). Adjusted for leakage, the emissions were 107.1, 47.3, 39.0, and 28.6 mg/l (0.405, 0.179, 0.148, and 0.108 gm/gal). Since no combustible gas detector measurements for leaks were made, a value of 1.0 was assumed for the potential volumetric recovery factor.

Test results from January 25, the first day of testing, were deleted from the calculations in the emission test report,[12] but no possible cause which might have explained the high values was provided. It was stated in the report that the values were not used "due to the inconsistency with other results." The emission values from the first test day have been included in the calculations used for evaluation of this control technique because no operational problems during the test have been reported. A possible cause could be maladjustment of the inlet damper which controls the amount of combustion air admitted to the combustion chamber.

Further details about the test are contained in the emmission test report.

C.3.6 Bulk Terminal Test No. 6

This tank truck gasoline loading terminal was selected for source testing because the loading facilities are vented directly to an AER Corporation thermal oxidizer (TO) unit. Two of the other thermal oxidizer units source tested by EPA were equipped with a vapor holder that allowed only vapors above the upper explosive limit to be vented to the unit (Bulk Terminal Test Nos. 4 and 7).

The terminal is equipped with three gasoline loading rack positions. Regular, premium, and unleaded gasoline are loaded at each of these racks. At one loading rack, the tank truck vapor vent line was connected to a turbine meter to measure the volume of vapors vented from the tank truck to the vapor control system. Integrated bag samples of vent gases from the trucks were taken at this point and tank truck loadings were monitored for leaks. A liquid sample for each type of gasoline loaded was also obtained for analysis. Testing was performed on January 10-12, 1978.

During the test period the terminal was in normal operation and the thermal oxidizer appeared to be operating properly. The daily throughput of gasoline approximated 757,000 to 1,135,500 liters (200,000 to 300,000 gallons).

The test appears to have been conducted according to the prescribed test procedure. The possibility exists that due to low temperature conditions, the vapors vented to the thermal oxidizer unit in some instances may have been below the lower explosive limit and could have passed through the thermal oxidizer without being incinerated. VOC emissions to the atmosphere from the thermal oxidizer were determined to be 21.4, 22.4, and 39.8 milligrams per liter (0.081, 0.085, and 0.151 gram per gallon) of gasoline loaded into the tank trucks. Emissions adjusted for leakage were 24.7, 27.0, and 50.9 mg/l (0.093, 0.102, and 0.193 gm/gal).

Further details are contained in the emission test report.[13]

C.3.7 Bulk Terminal Test No. 7

Testing was conducted February 23, 24 and 27, 1978, at a bulk terminal whose daily gasoline throughput is approximately 1,514,000 liters (400,000 gallons). Gasoline is dispensed from six loading racks through both bottom-loading and top-loading vapor recovery arms.

Air-vapor mixture displaced during loading is routed first to a liquid condensate tank, then to a vapor holder, and finally to an AER Corporation thermal oxidizer (TO) type vapor control unit. Propane is introduced into the vapor stream to keep the VOC concentration above the upper explosive limit. The specified test procedure was followed, except that VOC concentrations were measured as volume percent as butane. The control unit and other vapor control equipment at the terminal were in good condition. The control unit appeared to be functioning properly, and no problems with instrumentation were reported.

VOC emissions from the TO unit were 23.7, 7.5, and 10.3 milligrams per liter (0.090, 0.028, and 0.039 gram per gallon). Adjusted for leakage, the emissions were 29.4, 9.3, and 13.2 mg/l (0.111, 0.035, and 0.050 gm/gal).

Further details are contained in the emission test report.[14]

C.3.8 Bulk Terminal Test No. 8

Test No. 8 was conducted at a relatively small bulk terminal having only one gasoline loading rack; however, the throughput of the bottom-loading rack is approximately 380,000 liters (100,000 gallons) per day. Three grades of gasoline (premium, regular, and unleaded) are dispensed at the loading facility.

Vapors displaced from the gasoline tank trucks are vented to a refrigeration type (REF) vapor recovery unit, manufactured by Edwards Engineering Corporation. During the testing by EPA, which ran from December 17-19, 1974, 24 trucks were loaded with gasoline to determine the potential VOC emissions, actual VOC emissions, and the vapor recovery efficiency of the control unit.

In the refrigeration type system, VOC vapors and air from the tank trucks are directly processed and condensed in a double-pass finned-tube condenser. There are no saturators or vapor holder utilized in the system. The efficiency of the condenser is directly related to the temperature of the condensing unit. In normal operation, a condenser temperature of about -73°C (-100°F) is maintained.

Some operational problems with the control unit were encountered during the test period. A leak had developed in the high pressure section of the refrigeration system, resulting in refrigerant loss. This prevented the condenser from maintaining the design temperature.

Testing was resumed when the unit had been repaired, and the condenser had reached a temperature of -51°C (-60°F). Thus, it does not appear that design temperatures were reached at any time during testing.

VOC emissions from the recovery unit for the two successful days of testing were determined to be 33.3 and 39.4 milligrams per liter (0.126 and 0.149 gram per gallon) of gasoline loaded into the tank trucks. The emission rates adjusted for leakage were 44.0 and 54.4 mg/l (0.167 and 0.206 gm/gal). Leakage from the trucks was estimated to be 83.0 milligrams per liter (0.314 gram per gallon).

Further details are contained in the emission test report.[15]

C.3.9 Bulk Terminal Test No. 9

Test No. 9 was conducted at a medium size bulk terminal which contains two loading racks. The bottom-loading arms are situated on a concrete island so that the trucks can load concurrently to each other. Throughput at the terminal is about 1,430,000 liters (378,000 gallons) of gasoline per day.

Air-vapor mixture is displaced during loading and piped to an Edwards Engineering refrigeration type (REF) contol unit.

The facility and refrigeration unit were tested on September 20-22, 1976. During all three days the refrigeration unit was operating below capacity due to refrigerant loss caused by a leaking pump seal. As a result the actual refrigeration temperatures were -44 to -52°C (-47 to -61°F) rather than the -73°C (-100°F) design temperature. Daily average VOC emissions from the vapor recovery unit were determined to be 51.6, 52.3, and 29.9 milligrams per liter (0.195, 0.198, and 0.113 gram per gallon) of gasoline loaded into the tank trucks. Adjusted emissions were 72.2, 58.1, and 31.1 mg/liter (0.273, 0.220, and 0.118 gm/gal).

Further details are contained in the emission test report.[16]

C.3.10 Bulk Terminal Test No. 10

This tank truck gasoline loading terminal contains three bottom-loading racks. Throughput at the terminal is about 830,000 liters (220,000 gallons) per day. Testing was conducted on November 10-12, 1976.

The air-vapor mixture displaced from tank trucks during gasoline loading is routed to an Edwards Engineering refrigeration type (REF) control unit.

The facility and REF unit were tested for three days. During all three days the refrigeration unit was operating at capacity. Icing at the decanter occurred, caused by ambient air leaking into the separator, but did not cause any problems. VOC emissions from the vapor recovery unit were determined to be 76.6, 57.1, and 54.2 milligrams per liter (0.290, 0.216, and 0.205 gram per gallon). Emissions adjusted for leakage were 96.5, 58.8, and 61.8 mg/l (0.365, 0.223, and 0.234 gm/gal).

Further details are contained in the emission test report.[17]

C.3.11 Bulk Terminal Test No. 11

This test was performed on August 22-24, 1978 at a bulk terminal employing five loading racks to dispense fuel oil and three grades of gasoline. All racks use top splash loading to deliver the products to tank trucks. Only two of the racks load gasoline, and vapor recovery is used for both of these racks. The gasoline throughput of the terminal is considered confidential by the operator. Air-vapor mixture generated during loading operations is routed to a liquid knockout tank to remove any liquid gasoline and then to a refrigeration (REF) type control unit, manufactured by Tenney Engineering, Incorporated.

During testing, the REF unit did not maintain the low temperatures required for efficient vapor collection. The design temperature of the fin-tube condenser during operation is approximately -73°C (-100°F). The level of the methylene chloride cooling fluid (brine) was approximately 800 gallons below its capacity level during the test. As a result, the brine temperature ranged between -40°C (-40°F) and -54°C (-65°F). In addition, problems were encountered in measuring the very high VOC concentrations (as butane) at the inlet and outlet of the control unit. Only 20 out of 46 inlet concentration values and 27 out of 42 exhaust concentration values were successfully recorded during testing. Most of the successful readings were taken on the third day of testing, when a system to continuously dilute the inlet and exhaust streams was used. There are several possible causes for the high inlet concentrations to the REF unit. Top splash loading generates increased vapor concentration due to turbulence. Temperatures of between 38°C (100°F) and 49°C (120°F) were measured at the inlet volume meter. Also, the placement of the meter at the processor inlet instead of at the rack may have resulted in the concentration measurement of evaporated liquid gasoline which may have entered the line. Ambient temperatures were high and the vapors passed through a long, green metal line from the truck rack to the meter inlet.

Further details are contained in the emission test report.[18]

Emissions of VOCs from the control unit were 1318, 841, and 794 milligrams per liter (4.99, 3.18, and 3.01 grams per gallon). Since the adjustment factor for tank truck leakage is 1.00, the actual and adjusted emission values are identical.

C.3.12 Bulk Terminal Test No. 12

Test No. 12 was conducted September 26-28, 1978 at a bulk terminal with a daily average gasoline throughput of 1,514,000 liters (400,000 gallons). Gasoline and distillates are transferred to tank trucks through five loading racks, three of which use bottom loading and dispense gasoline.

Air-vapor mixture is piped from the loading racks first to a liquid knockout tank which removes any liquid gasoline in the line. The mixture passes from the knockout tank directly to a Tenney Engineering refrigeration (REF) type control unit.

Due to the mode of operation of the control unit during testing, a significant amount of air-vapor mixture collected at the loading racks passed through the unit without vapor recovery. Defrost cycles were scheduled to occur during the following time intervals:

Start Defrost	Finish Defrost
4 a.m.	5 a.m.
10 a.m.	11 a.m.
2 p.m.	3 p.m.
8 p.m.	9 p.m.

Two of these defrost cycles coincide with the daytime scheduling of the testing. Results were calculated for test runs during which no defrosting occurred. It is suspected that even these results do not accurately reflect the performance of the unit which would occur if the defrost schedule were corrected. Too-frequent defrost intervals may cause the accumulated frost to ice on the condenser coils, which would result in a reduction in heat transfer efficiency. Collection efficiency would be decreased as a result, even for the non-defrost runs. A manual defrost for the entire night of September 27 led to a somewhat improved collection efficiency on the third day of testing, September 28.

VOC concentrations were calculated as volume percent as butane. Emissions from the control unit were 67.2, 102.6, and 61.9 milligrams per liter (0.254, 0.388, and 0.234 gram per gallon). Adjusted for leakage, these emissions were 75.9, 102.6, and 68.1 mg/l (0.287, 0.388, and 0.258 gm/gal).

Further details of this test are contained in the emission test report.[19]

C.3.13 <u>Bulk Terminal Test No. 13</u>

This test was performed at a bulk terminal with an average gasoline throughput of approximately 1,514,000 liters per day (400,000 gallons per day). The terminal contains 14 racks using top splash loading which dispense xylene, fuel oil, and three grades of gasoline. Only the five racks loading gasoline route the displaced vapors to vapor recovery. The testing was conducted on October 10-12, 1978.

Air-vapor mixture displaced during loading is piped through a liquid knockout tank to an Edwards Engineering refrigeration (REF) type vapor recovery unit. During testing, the unit was operating well, as evidenced by its low brine pump supply temperature (-72°C, or -97°F). However, serious leakage in the terminal loading equipment prevented a large portion of the displaced air-vapor mixture from reaching the unit. Most loading racks leaked liquid gasoline at swivel joints, and vapors leaked from several locations, including:

1. Loading arm/hatch seal interface,
2. P-V vents and check valves, and
3. Flexible vapor return lines.

An air balance analysis showed that approximately 48 percent of the displaced air-vapor mixture leaked from the vapor collection system. Because of this leakage, the test results were not included in the evaluation of the REF control technology.

Further details are contained in the emission test report.[20]

C.3.14 Bulk Terminal Test No. 14

Test No. 14 was conducted at a bulk terminal that has an average gasoline throughput of approximately 600,000 liters (160,000 gallons) per day. The terminal was tested by EPA on December 11-12, 1974. The terminal has eight loading racks for various fuels, three of which dispense gasoline. Each of the gasoline loading racks is equipped for bottom loading of premium, regular, and unleaded gasoline. Also, on one of the gasoline racks, two grades of aviation fuel are dispensed and vapors are vented to the vapor control system.

Vapor hoses at each rack are manifolded to a common header venting to a saturator. The purpose of the saturator is to ensure that the vapors vented to the vapor holder are above the upper explosive limit. Saturated vapors pass to a vapor holder. At a preset volume the vapor holder automatically discharges to an 8,500 liter per minute (300 cfm) compression-refrigeration-absorption (CRA) system, manufactured by the Parker-Hannifin Corporation.

Testing was performed during 39 truck loadings to determine potential VOC emissions, actual VOC emissions, and vapor recovery efficiency of the system. Only two loading racks were tested. The other rack was not used for testing purposes because insufficient test equipment was available.

VOC emissions from the vapor recovery unit were determined to be 31.0 and 31.6 milligrams per liter (0.117 and 0.120 gram per gallon) for the two days of testing. When adjusted to account for leakage the emission rates from the unit were 73.5 and 57.2 mg/liter (0.278 and 0.217 gm/gal).

The only difficulties in testing encountered in the loading of gasoline were vapor leakage and spillage. Vapor losses occurred at almost all hatches and pressure vents at the top of the trucks. Liquid spillage occurred on occasion because of improper seating of the shut-off valve at the liquid connection to the tanker, and also from buckets used to catch a small amount of unleaded gasoline left in the tank truck compartments from the previous load.

Further details are contained in the emission test report.[21]

C.3.15 Bulk Terminal Test No. 15

This tank truck gasoline loading terminal contains four bottom-loading racks delivering 1,190,000 liters (315,000 gallons) of gasoline per day. The facility is attended for about 10 hours per day, but drivers have pass keys which permit loading 24 hours per day, 7 days per week. Testing was conducted on September 23-25, 1976.

The vapor recovery unit is a compression-refrigeration-absorption (CRA) unit, manufactured by the Rheems-Superior Corporation. The system handles emissions from the loading rack and from storage tank loading operations (pipeline delivery).

Gasoline vapors, collected from tank truck loading operations, are first sprayed with gasoline to ensure that they are saturated (above the explosive range). The vapors are then vented to a regular gasoline product storage tank equipped with a lifter roof. When the roof reaches a pre-determined level the vapors are vented to the CRA unit where the vapors are sprayed with gasoline again (to saturate) and then compressed and cooled. The vapors are then vented to an absorber where they are absorbed in fresh gasoline, and the cleaned gases are exhausted to atmosphere.

Throughout the test period, loading procedures were normal and the unit operated with no apparent problems. However, liquid buildup in the sample line on September 25 led to invalid VOC concentration measurements on that day. In addition to truck and CRA outlets being monitored, the liquid levels in the storage tanks, the flow to the pipeline, and the liquid volumes into and out of the CRA unit were monitored.

One problem seen was that drivers frequently drained trucks of remaining gasoline into a sump before loading. This caused several liters of gasoline to evaporate to the atmosphere during the course of the test period. This loss cannot be quantified. Daily average VOC emissions from the vapor recovery unit for the first two test days were determined to be 30.7 and 30.5 milligrams per liter (0.116 and 0.115 gram per gallon) of gasoline loaded into the tank trucks. The emission rates adjusted for leakage were 44.5 and 47.0 mg/liter (0.168 and 0.178 gm/gal).

Trucks loading diesel fuel also hooked up to the vapor return line and vented emissions to the saturator of the CRA. Further details are contained in the emission test report.[22]

C.3.16 Bulk Terminal Test No. 16

Test No. 16 was conducted at a terminal containing two loading racks having four bottom-loading dispensing arms each. The gasoline throughput of the terminal is considered confidential by the operator.

Air-vapor mixture displaced from loading tank trucks is directed to a liquid knockout tank, a vapor holding tank, and then to a vapor control unit. The control unit is the compression-refrigeration-absorption (CRA) type, manufactured by Trico-Superior, Incorporated. Testing was performed on four days, February 20-21, 1978, and March 8-9, 1978.

No control system upsets or instrument malfunctions were reported during the test. VOC concentrations were measured as volume percent as butane. No measurements of leaks were made with a combustible gas detector, so the value of $(V/L)_p$ was assumed to be 1.0. Data allowing calculation of V/L were not collected on March 8 and 9, and processor data $(M/L)_e$ were not obtained on February 20. Daily average VOC emission levels on three days of testing were 61.2, 59.5, and 57.2 milligrams per liter (0.232, 0.225, and 0.217 gram per gallon). Adjusted for tank truck leakage, emissions on February 21 were 88.1 mg/l (0.333 gm/gal).

Further details are contained in the emission test report.[23]

C.3.17 Bulk Terminal Test No. 17

This tank truck gasoline loading terminal vapor control system was tested by EPA on May 2-4, 1978. The terminal has a gasoline throughput that approximates 1,000,000 liters (264,000 gallons) per day.

The vapor control system uses a Parker-Hannifin compression-refrigeration-absorption (CRA) unit. The unit was tested to determine its efficiency in removing VOCs generated during tank truck gasoline loading.

The total VOC concentration, at both the inlet and outlet of the vapor recovery unit, was continuously monitored, and the vapor volumes were determined at these two sampling points.

No major problems during testing were reported. Daily average VOC emissions to the atmosphere from the vapor recovery unit were 40.9, 45.1, and 35.9 milligrams per liter (0.155, 0.171, and 0.136 gram per gallon) of gasoline loaded. The control unit emissions adjusted for system leaks were 78.5, 58.2, and 52.1 mg/l (0.297, 0.220, and 0.197 gm/gal) of gasoline loaded.

Further details are contained in the emission test report.[24]

C.3.18 Bulk Terminal Test No. 18

Test No. 18 was conducted at a bulk terminal whose daily gasoline throughput averages 1,514,000 liters (400,000 gallons). Gasoline and distillates are dispensed through six loading racks, four of which use bottom loading and dispense gasoline. Testing was performed on August 2-4, 1978.

Air-vapor mixture displaced during tank truck loading is piped to a saturator to raise the VOC concentration above the upper explosive limit. After saturation, the mixture is stored in a bladder-type vapor holder. At a preset level, the control unit is started automatically to process the vapors. This unit is a Trico-Superior compression-refrigeration-absorption (CRA) type unit.

No problems were reported during the testing in regard to the operation of the control unit or test instrumentation. VOC concentrations were measured in volume percent as butane. Five tank trucks were determined to be vapor-tight out of the 59 for which leak measurements were taken. VOC emissions from the control unit were 32.2, 43.1, and 43.0 milligrams per liter (0.122, 0.163, and 0.163 gram per gallon). Adjusted for leakage, emissions were 41.5, 65.1, and 52.9 mg/l (0.157, 0.246, and 0.200 gm/gal).

Further details are contained in the emission test report.[25]

C.3.19 Bulk Terminal Test No. 19

Test No. 19 was performed at a bulk terminal containing seven loading racks which dispense gasoline and distillates. Three of the racks use bottom loading, and two of these dispense gasoline. The daily gasoline throughput at the terminal is considered confidential by the operator. Testing was performed at the terminal on September 19-21, 1978. The results presented are for only one day of testing, September 21, 1978. Air-vapor leakage at the pressure-vacuum relief valve on one of the unleaded gasoline storage tanks made it necessary to omit the September 19 test data. A disconnected volume meter at the control system exhaust on September 20 invalidated the results from that day.

Air-vapor mixture generated at the three bottom-loading racks is routed to a vapor holder, and then to a saturator, where gasoline is sprayed into the mixture. The two unleaded gasoline storage tanks also act as vapor holders. When the vapor holder reaches a preset capacity level, the control unit starts automatically and vapors are sent through the unit. This unit is a Parker-Hannifin compression-refrigeration-absorption (CRA) type unit.

There were no significant equipment problems reported during the testing on September 21. Five of the tank trucks were measured to be vapor-tight out of the 19 loadings tested. Total VOC concentrations were measured in volume percent as butane. VOC emissions exhausted from the control unit were 85.9 milligrams per liter (0.325 gram per gallon). Adjusted for leaks, the emissions from the unit were 91.0 mg/l (0.344 gm/gal).

Further details are contained in the emission test report.[26]

C.3.20 Bulk Terminal Test No. 20

Test No. 20 was performed at a complex consisting of four bulk terminals whose total average daily throughput of gasoline is approximately 5.68 million liters (1.5 million gallons). VOC vapors from all four terminals are routed to a single vapor control unit. The control unit is a compression-refrigeration-condensation (CRC) type unit, manufactured by Gulf Environmental Systems Company (GESCO). The operation of this unit is somewhat similar to that of the CRA unit. Testing was performed on four days, February 1-2, 1978, and March 6-7, 1978.

VOC vapors displaced from tank trucks during filling are piped to a vapor holding tank with an internal flexible bladder. When the vapor volume reaches a preset level, the control unit starts and processes the collected vapors. Incoming vapors are first contacted with recovered product in a saturator, where the VOC concentration is raised above the explosive range. The saturated vapors are then compressed in a two-stage compressor with an intercooler. The compressed vapors pass through a condenser where they are cooled, condensed and returned to gasoline recovery with the condensate from the intercooler. Recovered gasoline is distributed to each terminal in the complex based on its throughput for a given period.

The control unit was operated with a defective compressor on February 1 and 2, so the results from these days are not included in the data. Daily average VOC emission levels from the CRC unit during the two successful test days were 41.0 and 44.4 milligrams per liter (0.155 and 0.168 gram per gallon) of gasoline loaded. Adjusted for leakage, the emission levels were 48.4 and 55.9 mg/l (0.183 and 0.212 gm/gal).

Further details are contained in the emission test report.[27]

C.3.21 Bulk Terminal Test No. 21

Test No. 21 was performed at a bulk terminal containing nine loading racks, five of which dispense gasoline through bottom-loading arms. Daily gasoline throughput at the terminal is considered confidential by the terminal operator. Testing was performed on August 16-18, 1978.

Air-vapor mixture displaced from tank trucks during loading is routed through a saturator, and then to a vapor holder. The vapor holder is followed by a GESCO compression-refrigeration-condensation (CRC) type control unit, which starts automatically when a preset volume level is reached in the vapor holder.

Major operational problems with the vapor holder made some of the calculations impossible. During the testing period, the control unit would operate only when switched on manually because the automatic start switch was inoperative. The unit was sometimes not started soon enough and air-vapor mixture would overfill the vapor holder and exhaust to atmosphere through the pressure relief valve. It is estimated that approximately 81 percent of the displaced mixture leaked out of the system before reaching the control unit. VOC emissions from the control unit, emissions adjusted for leaks, and unit control efficiency could not be calculated.

Further details of this test are contained in the emission test report.[28]

C.3.22 Bulk Terminal Test No. 22

Test No. 22 was conducted at a bulk terminal which has an average daily throughput of approximately 1,514,000 liters (400,000 gallons). The terminal contains four loading racks, two of which top load gasoline with splash type nozzles, and one of which bottom loads gasoline. The air-vapor mixture in tank trucks being loaded is collected at the racks and routed to a lean oil absorption (LOA) control unit, manufactured by Southwest Industries (Ingersoll-Rand Corporation). Testing at this terminal was conducted on April 11-13, 1978.

While the average unit control efficiency for the three-day test was quite low (78.9 percent), by increasing the lean oil flow to the absorber column the unit achieved an efficiency of 85.9 percent on one of the test days (April 12). This indicates that the LOA unit is capable of improved efficiency when operating conditions are modified. The maximum benefit achievable by making such changes is not known.

Testing was performed during 36 tank truck loadings. Operations at the terminal were normal and no instrument problems were reported. Daily average VOC emissions from the vapor recovery unit were 97.0, 52.9, and 86.7 milligrams per liter (0.367, 0.200, and 0.328 gram per gallon) of gasoline loaded. Emission levels adjusted for leakage were 130, 73.0, and 119 mg/l (0.492, 0.276, and 0.450 gm/gal) for the three days of testing.

Further details are contained in the emission test report.[29]

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APPENDIX D

EMISSION MEASUREMENT AND CONTINUOUS MONITORING

There are three sections of the proposed bulk gasoline terminal standard that would require performance test procedures to determine compliance: (1) vapor-tightness of gasoline tank trucks, (2) leaks from vapor collection and processing equipment, and (3) mass emissions from the vapor processor outlet. In order to conduct these performance tests, six new reference test methods were developed: Methods 2A, 2B, 21, 25A, 25B, and 27. Each performance test procedure and its applicable new reference methods are discussed in the following sections. Also, the emission testing and test method development conducted for this proposed regulation are summarized. Finally, various possible monitoring approaches are discussed.

D.1 GASOLINE TANK TRUCKS

D.1.1 Performance Test Method

The proposed gasoline terminal regulation would require that all gasoline tank trucks which are loaded at an affected facility be vapor-tight. The recommended measurement procedure is Reference Method 27, "Determination of Vapor Tightness of Gasoline Delivery Tank Using a Pressure-Vacuum Test." The method uses a static pressure-vacuum test procedure; the tank is pressurized (or alternately evacuated) to a predetermined level, and the change in pressure versus time is compared to the allowable pressure change specified in the regulation.

To conduct this test, a tank must be removed from service, emptied of all liquid, and protected from direct sunlight. It is recommended that all volatile vapors be purged from the tank prior to testing. One acceptable purging method is to carry a load of non-volatile liquid fuel, such as diesel or heating oil, immediately prior to the test, thus flushing out all the volatile gasoline vapors. This is the easiest and most effective purging procedure; however, the flexibility and opportunity of carrying a diesel load is not available to all tank owners. A second purging method is to remove the volatile vapors by blowing ambient air into each tank compartment for at least 20 minutes. This second method is usually not as effective. Purging of volatile vapors is needed because test data show that gasoline vapors in a tank may cause testing inconsistencies. However, it is possible to test without purging if there is enough time for the vapors to stabilize prior to testing. To ensure that the vapors have stabilized, a provision is included in Method 27 which requires that the test be conducted with the same results (within the precision of the measuring instruments) on two consecutive runs. This allows the owner the choice of purging the volatile vapors prior to testing or waiting for a longer stabilization period during the actual testing.

The vapor-tightness performance criteria (similar to emission limits) are not included in Method 27, but instead are specified in each individual regulation that calls for using Method 27. For the gasoline terminal regulation, the recommended performance level is that the pressure in the tank shall not change by more than 75 mm (3 inches) of water in 5 minutes when pressurized to 450 mm (18 inches) of water. Because the proposed terminal standard would regulate only the loading of product into a tank truck, (that is, when a tank is under pressure), only the pressure part of the pressure-vacuum test in Method 27 is applicable.

The procedure in Method 27 requires no special testing instruments or equipment. The total time needed for this test procedure, including minor maintenance, is 1 to 4 hours, depending on the purging procedure used. The cost of conducting this test is related to the testing time period, but averages about $100. (This cost does not include the additional cost of repair and replacement parts if a leak is found).

Several other test methods and regulatory approaches were considered during the background study for the gasoline terminal regulation. Eight other candidate test methods were investigated for their use and acceptability as a vapor-tightness test procedure. These alternative methods are volume leakage rate, "quick" pressure decay, combustible gas detector, sonic detector, bubble indication, sensory detection, bag capture, and vapor-to-liquid volume ratio methods. A description, evaluation, and reason for rejection of each of these methods is presented in detail in another EPA document[1] and a published paper.[2]

D.1.2 Emission Testing and Measurement Methods

During the standard support study for the bulk gasoline terminal regulation, EPA conducted a field testing program to develop a test procedure for determining vapor-tightness of tank trucks. Tests were conducted in California because at that time only California required tank truck fleet operators to maintain all tanks in a vapor-tight condition, as defined by the California Air Resources Board (CARB) certification criteria. The delivery tank truck fleet to be tested was selected so that a representative cross-section of tanks was obtained. Test were conducted at both bottom and top loading terminals over a 2-week period in which over 200 tank loadings were monitored. Each of the 27 selected tanks was also removed from service for a half-day for further shop tests.

Seven test methods were included in the field test program: combustible gas detector, sonic detector, sensory detection, vapor-to-liquid volume ratio, bubble indication, volume leakage, and static pressure-vacuum test methods. In addition, the bag capture method was observed in the field, as conducted by San Diego County officials, and the "quick" pressure decay method was investigated on a bench-scale model tank in the laboratory.

A description of the testing program, the candidate methods, and an evaluation of the results can be found in a previously published paper[2] and another EPA document.[1]

The static pressure-vacuum testing procedure which was used during this program is very similar to the recommended performance test procedure. Two areas of difference concern the allowed amount of pressure drop and the procedure to ensure stabilization. In the field testing program, the CARB pressure test criterion was used, which at the time required that the pressure in a tank not change by more than 2 inches of water in 5 minutes when initially pressurized to 18 inches of water. The vapor-tightness criterion in the proposed terminal regulation allows a pressure change of 3 inches. However, this difference in the test procedures does not affect the usefulness of the field test data because the period for the pressure test was extended during the field tests until a 3-inch drop was also attained.

During the field testing, it was discovered that failure to remove all the volatile vapors caused testing inconsistencies and erroneous results. Sometimes during the pressure test, the pressure in the tank surprisingly increased with time instead of decreasing as expected. Repeatable results were difficult to obtain, and long stabilization periods were sometimes necessary before meaningful or consistent test results occurred. Because of these problems, a provision to ensure repeatability and accuracy was later developed and included in Method 27. Although repeat runs were usually not conducted during the field tests, the usefulness of most of the test data was not affected. No stabilization problems were encountered at one terminal where diesel fuel purging was used. At the other terminal where air purging was used, the stabilization problems were discovered after the first few tests, and testing repetitions were conducted on the remaining tanks. Thus, the overall differences between the test procedures are slight and should not affect the representativeness or the usefulness of the emission test data.

D.1.3 Monitoring Systems and Devices

Because the vapor-tightness determination procedure is not a typical direct emission measurement technique, and because leakage from gasoline tank truck fittings is not a typical emission source, there are no continuous monitoring approaches that are directly applicable. Continual surveillance is achieved by repeated monitoring or testing of the tank trucks.

The interval between tests could be either monthly, quarterly, semiannually, or annually, depending on the likelihood of a leak developing and on the cost-effectiveness of the test. A testing interval of 1 year is recommended for two reasons. First, it is consistent with the current California regulation and with the regulation recommended in the Control Techniques Guideline document[3] (which many States are now adopting in the State Implementation Plans). Second, analysis of test data shows that the requirement for an annual test results in average tank leakage emissions of 10 percent; average leakage for a 6-month test would be 7 percent; the leakage at the time of the vapor-tightness test is 1 percent.[2] Tank trucks rarely remain vapor-tight due to normal daily wear-and-tear. Because a 6-month test interval is only marginally more effective than a 1-year interval, and because of the cost and inconvenience of the testing, an annual test was selected.

The recommended monitoring procedure is Method 27; thus, the monitoring procedure is identical to the performance test. Accordingly, the cost and the time for monitoring are the same as those for the initial compliance test.

D.2 VAPOR COLLECTION AND PROCESSING EQUIPMENT

D.2.1 Performance Test Method

The second part of the proposed gasoline terminal regulation that would require a performance test concerns fugitive emissions from a terminal's vapor collection and processing equipment. There are several pieces of equipment at a typical vapor processing unit which are especially prone to developing leaks, such as pump seals, valves, and vapor holder diaphragm and relief vents. Field tests have shown that emissions from these sources may be significant, emitting up to 80 percent of the collected vapors from the loading racks before the vapors enter the control unit. Besides being emission sources, large leakage from these sources would affect the representativeness of emission measurements at the processor outlet.

The recommended measurement procedure for leaks is Reference Method 21, "Determination of Volatile Organic Compound Leaks", which is applicable for the detection of VOC leaks from organic liquid and vapor processing equipment. This method employs a portable analyzer to detect the presence of organic vapors at the surface of the interface where direct leakage to atmosphere could occur. The approach of this technique assumes that if an organic leak exists there will be an increased vapor concentration in the vicinity of the leak, and that the measured concentration is generally proportional to the mass emission rate of the organic compound.

Instrument specifications, performance criteria, and calibration procedures are included in the method to ensure the uniformity and accuracy of instrument measurements. The sampling probe should be positioned at the surface of each potential leakage source, essentially 0 centimeter distance.

The highest instrument reading is recorded and compared to the allowable reading specified in the applicable regulation.

The definition of a leak (similar to an emission limit) is not included in Method 21, but instead is specified in each individual regulation that calls for Method 21. For the proposed terminal regulation, the recommended leak definition is any reading greater than or equal to 10,000 ppm when the instrument is calibrated to methane. A leak detection survey is recommended immediately prior to and after any performance test of processor outlet emissions. This ensures the validity of the outlet test results. Periodic leak detection surveys may also be required to ensure that no major leak has developed since the performance test.

There are several commercially available analyzers that can meet the specifications in Method 21. The estimated purchase cost for an analyzer ranges from $1,000 to $5,000 depending on the type and optional equipment. Because the collection and processing equipment at a terminal is not extensive, only about 15 minutes would be needed to survey for leaks. An additional 15 to 30 minutes would be required to prepare and calibrate the hydrocarbon analyzer.

All the developmental work on Method 21 and on the regulatory approach for VOC leakage sources was done during the background support studies for two other EPA standards: (1) New Source Performance Standards (NSPS) for VOC fugitive emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI), and (2) National Emission Standard for Hazardous Air Pollutants (NESHAP) for fugitive benzene emissions. The background documents[4,5] for these two standards discuss the development of Reference Method 21, its selection over other test methods, the emission testing performed, the interpretation of the resulting data base, the selection of the regulatory approach, and the selection of a leak definition.

The leak definition, performance test, and application of Method 21 for the terminal standard were selected as much as possible to be consistent with these other two standards. It is assumed that the data base gathered from emission tests at petroleum refineries and SOCMI facilities and the rationale for the regulatory approach is directly applicable to gasoline terminals. This assumption was made because organic processing equipment and its usage at SOCMI and refinery facilities is similar to that at terminal facilities.

D.2.2 Emission Testing and Measurement Methods

During the emission testing for bulk gasoline terminals, no formal lead detection survey of a terminal's vapor collection and processing equipment was conducted. Extensive testing was done, however, in support studies for other EPA fugitive emission standards and guideline documents in related industries (SOCMI, petroleum refineries, and benzene fugitive emission sources). Details of these testing programs are found in other EPA documents.[4,5,6]

Because the organic processing equipment at gasoline terminals is similar in its design and usage to equipment at these other facilities, it is assumed that the emission test results are applicable to the gasoline terminal regulation. Although the amount of equipment at an individual terminal is not as extensive as that at facilities in these other industries, the ratio of leaking sources versus potential sources should be the same.

Even though no Method 21 leak detection surveys were performed during the terminal test program, sources of leakage were discovered in the vapor processing equipment at some terminals. These leaks were discovered by sensory detection, combustible gas analyzer monitoring (a non-rigorous procedure similar to Method 21), or analysis of the outlet emission test results. One common source of extensive leakage was the processor's vapor holder. Air material-balance calculations showed that 50 to 80 percent of the uncontrolled emissions (prior to processing) were sometimes emitted from this source.

D.2.3 Monitoring Systems and Devices

Because the leak detection procedure is not a typical emission measurement technique, and because leakage sources are not typical emission sources, there are no continuous monitoring approaches that are directly applicable. Continual surveillance is achieved by repeated monitoring or screening of all affected potential leak sources. The monitoring interval could be either monthly, quarterly, or annually, depending on the likelihood of a leak developing.

The recommended monitoring procedure is Method 21; thus, the monitoring procedure is identical to the performance test. Accordingly, the cost and time for monitoring is the same as for the performance test procedure, 15 minutes to survey for leaks and 15 to 30 minutes to prepare and calibrate the analyzer.

Instead of monitoring for leaks using a Method 21-type procedure, an alternate approach was considered which required periodic visual and olfactory inspections by terminal personnel. This serves the same purpose in that any gross leakage or maintenance problems would be discovered during the periodic inspections. The sensory inspection would take less time and be less expensive because a portable hydrocarbon analyzer is not needed. However, because of the subjectivity of an individual's sensory perceptions, it would be difficult to determine if smaller leaks were in fact violations or not.

D.3 VAPOR PROCESSOR EXHAUST OUTLET

D.3.1 <u>Performance Test Method</u>

The third section of the proposed terminal regulation that would require a performance test procedure concerns the emissions from a terminal's vapor control unit. The format of the standard is mass of VOC emitted per volume of gasoline loaded. To determine this, three measurements are needed: (1) VOC concentration in the stack, (2) gas volume exhausted, and (3) gasoline throughput during the test period. Four new EPA Reference Methods had to be developed; these methods are combined in a performance test procedure that is contained in the proposed regulation itself. The performance test procedure defines the test length and the conditions under which testing is acceptable, as well as the way the reference method measurements are combined to attain the final result.

a. Concentration Measurements

Prior to the gasoline terminal standard, the only Reference Method for measuring VOC concentration was Method 25, "Determination of Total Gaseous Nonmethane Organic Content (TGNMO)." However, the TGNMO procedure is not recommended for the terminal standard because it does not continuously measure concentration and it is awkward to use for long test periods. A terminal processor operates intermittently, and there may be a significant variability in the outlet concentration over short periods of time. These variations would be masked if the testing procedure used an integrated sampling approach as in Method 25. Instead, a new continuous VOC measurement method was developed, because with continuous measurements, the short-term variations in concentration can be noted. The continuous records are then averaged or integrated as necessary to obtain an average result for the measurement period.

The recommended VOC measurement method is Reference Method 25A or 25B. Method 25A, "Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer," applies to the measurement of total gaseous organic concentration of vapors consisting of alkanes, and/or arenes (aromatic hydrocarbons). The instrument is calibrated in terms of propane or another appropriate organic compound. A sample is extracted from the source through a heated sample line and glass fiber filter and routed to a flame ionization analyzer (FIA). (Provisions are included for eliminating the heated sampling line and glass fiber filter under some sampling conditions.) Results are reported as concentration equivalents of the calibration gas organic constituent or organic carbon.

Method 25B, "Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer," is identical to Method 25A except that a different instrument is used. Method 25B applies to the measurement of total gaseous organic concentration of vapor consisting primarily of alkanes. The sample is extracted as described in Method 25A and is analyzed with a nondispersive infrared analyzer (NDIR).

In both the FIA and NDIR analysis approaches, instrument calibrations are based on a single reference compound. For the proposed gasoline terminal standard, propane or butane is the recommended calibration compound. As a result, the sample concentration measurements are on the basis of that reference and are not necessarily true hydrocarbon concentrations. Calculation of emissions on a mass basis will not be affected because the response of the instruments is proportional to carbon content for similar compounds, in this case gasoline vapors. Mass results would be equivalent using either the concentration and molecular weight based on a reference gas or the true concentration and true average molecular weight of the hydrocarbons. The advantage of using a single component calibration is that chromatographic techniques are not required to isolate and quantify the individual compounds present.

The VOC analysis techniques discussed above measure total hydrocarbons including methane and ethane. Chromatographic analyses during prior field tests have indicated that significant quantities of methane and ethane may sometimes be present in the vapors emitted. If it is expected that methane or ethane is present in significant quantities, appropriate samples are required for chromatographic analysis to adjust the results to a nonmethane-nonethane basis.

b. Volume Measurements

Prior to this regulation, the only Reference Method for determining volumetric flow in stacks was Method 2, which uses a pitot tube velocity traverse procedure. However, Method 2 is usable only in large stacks (diameter greater than 12 inches) with constant and continuous flow. This method is not appropriate for gasoline terminal volume measurements because the flow is intermittent and highly variable, and often the stacks are only 6 to 8 inches in diameter. Thus, during the support study for the terminal standard, two new methods were developed to measure exhaust volumes from vapor processors.

Reference Method 2A or 2B is the recommended procedure for measurement of total volume of the exit gases from a vapor processor outlet. Method 2A, "Direct Measurement of Gas Volume Through Pipes and Small Ducts," applies to the measurement of gas flow rates in pipes and small ducts, either in-line or at exhaust positions, within the temperature range of 0 to 50°C. A totalizing gas volume meter is installed in the pipe duct, and a direct, continual volume measurement is obtained. Temperature and pressure measurements are made to correct the volume to standard conditions.

If a terminal's vapor processor is an incinerator, Reference Method 2B is recommended to determine the exhaust volume. Method 2B, "Determination of Exhaust Gas Volume Flow Rate from Gasoline Vapor Incinerators," is applicable for the measurement of exhaust volume flow rate from incinerators that process gasoline vapors consisting generally of nonmethane alkanes, alkenes, and/or arenes (aromatic hydrocarbons). It is assumed that the amount of auxiliary fuel is negligible. The procedure to determine the exhaust flow is complex, requiring five separate continuous measurements. The inlet VOC concentration and volume are measured using Methods 25A or 25B, and Method 2A, respectively. At the outlet, the VOC concentration is obtained (Method 25A or 25B) as well as the CO and CO_2 concentrations (Method 10). The exhaust volume is calculated from these five measured values using a carbon atom material balance.

An alternate procedure to Method 2A would be the use of a flow rate meter such as an orifice, venturi, or pitot tube device. The continuous flow rate records could be integrated to determine a total volume displaced or emitted during the measurement period. In addition to the complication caused by variable flow rates, the changes in gas composition must be known to accurately calculate the metered gas density during each measurement period. Directly measuring flow rate instead of total volume (as in Method 2A) is not recommended. However, there are some cases where the use of a total volume meter is not possible, and some form of rate meter must be used. These cases occur when the processing unit vent size is relatively large and pressure drop restrictions prevent reducing the vent diameter to that of the volume meter.

c. Mass Emissions

The VOC concentration and volume measurements are combined to determine the processor's mass emissions. To determine the total VOC mass emissions during the entire test period, the VOC mass emitted is determined for small incremental periods, each 5-minute interval and increment thereof when the processor is operating, and each 15-minute interval and increment thereof during non-operation. These incremental emissions are then summed for the entire test period. Because VOC concentrations and flow rate may vary significantly within a brief time period, these short incremental calculation intervals are needed so that short-term variations in emission rates can be noted.

d. Gasoline Throughput

The format of the proposed gasoline terminal regulation is mass emitted per volume of gasoline loaded. The amount of gasoline dispensed during the testing period is easily determined either from plant records or by reading all of the gasoline pump meters at the beginning and end of the test.

e. Test Period

The test period specification is based on a combination of field experience and minimum data requirements. Flexibility and variability for the test period are necessary in order to account for the tremendous variability among terminals, ensuring a test of adequate length along with a minimum number of tank loadings and processor operating cycles.

The recommended test period is 6 hours, during which at least 300,000 liters of gasoline are loaded into tank trucks. If a terminal's throughput is less than 300,000 liters in 6 hours, then the testing must be extended until 300,000 liters is dispensed. If a terminal closes down overnight before the minimum throughput requirement is met, then testing must be continued on the following day.

For terminals which have intermittent vapor processing systems (ones that employ vapor holders), the test period must also include at least two full operating cycles of the processing unit.

Most of the emission test data was collected following the test procedure in a draft version of EPA's Control Techniques Guideline document[8]. The recommended normal test period for these tests was three 8-hour repetitions. The intent of the testing was to obtain not only outlet emission data, but also inlet mass flow rates, processor control efficiency, overall terminal collection and control efficiency, and tank truck leakage emissions. The representativeness of these results could be affected by uncontrollable variation in the amount of tank leakage, previous cargo carried, whether balancing was done during unloading, and weather conditions. A longer 3-day averaging test time was needed to reduce the impact of these variations, as well as the normal day-to-day variations in loading frequency and terminal operation. Because the proposed standard for terminals only regulates outlet emissions, and because outlet emissions are not affected greatly by the above-mentioned variations, a shorter test period of 6 hours is sufficient.

Review of the emission test data used to support this standard indicates that the test time period for each day of testing ranged from 3 to 10 hours. (One terminal, however, had to be tested for 20 hours per day for 3 days, because the vapors were stored in a large vapor holder in a storage tank and the processor rarely operated). The specified 8-hour test length was often shortened due to testing instrument problems, vapor processor breakdowns, inclement weather, or minimal throughput during terminal off-hours. Based on this data base, a 6-hour testing period was selected.

f. Terminal Status During Test Period

The recommended test procedure is designed to measure control system performance under conditions of normal operation. Normal operation will vary from terminal to terminal and day to day. Because of the large differences in terminal operations, no specific criteria can be set forth to define normal operation. Enforcement and terminal personnel must determine representative normal testing conditions on a case-by-case basis. The following guidelines are recommended to assist in this.

1. Testing should be conducted during the 6-hour period during which the highest throughput normally occurs.
2. Switch loading should be minimized as much as possible.
3. All loading racks which are controlled by the system under test should be open. Simultaneous use of more than one loading rack should occur to the extent that such use would normally occur.
4. Simultaneous use of more than one dispenser on each loading rack should occur to the extent that such use would normally occur.
5. Dispensing rates should be set at the normal rate at which the equipment is designed to be operated. Automatic product dispensers are to be used according to normal operating practices.
6. Tank truck leakage should be minimized as much as possible.
7. Back-pressure in the vapor collection system should never exceed the pressure test criteria for tank trucks, in this case 18 inches of water.

g. Cost

Conducting a performance test using these procedures would cost a facility between $5,000 and $10,000, depending on the type of vapor processing unit.

D.3.2. Emission Testing and Measurement Methods

During the support study for the proposed terminal standard, EPA conducted 22 emission tests. These tests occurred over a 5-year period (November 1973 to October 1978). During this time period, the test procedure was changed and refined as more experience and knowledge were obtained. Most of the testing closely followed a test procedure in a draft version[8] of EPA's Control Techniques Guideline document. This draft test procedure recommended three 8-hour test runs and included extra measurements and calculations to determine many other results besides simply outlet mass emission. Thus, the emission testing procedures used in the background study were more comprehensive than the recommended test procedure for the proposed regulation.

The recommended test procedure for the proposed regulation determines outlet mass emissions over a 6-hour period using Reference Methods 2A, 2B, 25A, and 25B. This is essentially the same as the emission testing procedures used in the support study to determine outlet mass emissions. Thus, the data base is applicable for support of the terminal regulation.

Because of the tremendous variability among terminals, and because the testing was conducted over a 5-year period as the test procedures were being developed, there are some differences in the test procedures and in the terminal conditions during the 22 tests. Each test is discussed in Appendix C of this document, giving reasons for rejecting some of the test results.

D.3.3 Monitoring Systems and Devices

Continuous monitoring of the performance of a vapor control system can be accomplished by either an emission measurement or process parameter measurement approach.

There are presently no demonstrated continuous monitoring systems commercially available which monitor vapor processor exhaust VOC emissions in the units of the standard (mg/liter). This monitoring would require measuring not only VOC exhaust concentration, but also exhaust gas volume, volume of product dispensed, temperature, and pressure. An overall cost for a complete monitoring system is difficult to estimate due to the number of component combinations possible. The purchase and installation cost of an entire monitoring system (including VOC concentration monitor, volume meters, recording devices, and automatic data reduction) is estimated to be $25,000. Operating costs are estimated at $25,000 per year.

Monitoring equipment is commercially available to monitor the operational or process variables associated with vapor control system operation. Monitoring of operations indicates whether the vapor processing system is being properly operated and maintained, and whether the processor is continuously reducing VOC emissions to an acceptable level. The variable which would yield the best indication of system operation is VOC concentration at the processor outlet. Extremely accurate measurements would not be required because the purpose of the monitoring is not to determine the exact outlet emissions but rather to indicate operational and maintenance practices regarding the vapor processor. Thus the accuracy of FIA and NDIR type instruments is not needed, and less accurate, less costly instruments which use different detection principles are acceptable. Monitors for this type of continuous VOC measurement typically cost about $6,000 to purchase and install, and $6,000 annually to calibrate, operate, maintain, and reduce the data. To achieve representative VOC concentration measurements at the processor outlet, the concentration monitoring device should be installed in the exhaust vent at least two equivalent stack diameters from the exit point, and protected from any interferences due to wind, weather, or other processes.

For some vapor processing systems, monitoring of a process parameter may yield as accurate an indication of system operation as the exhaust VOC concentration. For example, temperature monitoring in the case of thermal oxidation or refrigeration systems may indicate proper operation and maintenance of these systems. Parameter monitoring equipment would typically cost about $3,000 plus $3,000 annually to operate, maintain, periodically calibrate, and reduce the data into the desired format. Because control system design is constantly changing and being upgraded in this industry, all acceptable process parameters for all systems cannot be specified. Substituting the monitoring of vapor processing system process parameters for the monitoring of exhaust VOC concentration is valid if it can be demonstrated that the value of the process parameter is indicative of proper operation of the processing system and is related to the exhaust VOC content. Monitoring of any such parameters would have to be approved by enforcement officials on a case-by-case basis.

If the VOC outlet concentration is monitored or if an operational parameter is monitored, then continual surveillance is achieved by comparing the monitored value of the concentration or parameter to the value which occurred during the last successful performance test.

The performance test period for gasoline terminals is at least 6 hours. During the performance test, the average VOC outlet concentration or the average value of the selected operational parameter should be determined. Excess emissions (for monitoring purposes) are then defined as any 6-hour period during which the value of the monitored concentration or parameter exceeds the average value measured during the 6-hour performance test.

EPA does not currently have any experience with continuous monitoring of VOC exhaust concentration or operational parameters of vapor processing units. Therefore, performance specifications for the sensing instruments cannot be recommended at this time. Examples of such specifications tnat were developed for sulfur dioxide and nitrogen oxides instrument systems can be found in Appendix B of 40 CFR Part 60 (Federal Register September 11, 1974).

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15. SUPPLEMENTARY NOTES

16. ABSTRACT

Standards of performance to control volatile organic compound emissions from new, modified, and reconstructed bulk gasoline terminal loading racks are being proposed under the authority of Section 111 of the Clean Air Act. This document contains background information and enviromental and economic assessments of the regulatory alternatives considered in developing the proposed standards.

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