Vapor Collection and Control Options for Storage and Transfer Operations in the Petroleum Industry

API PUBLICATION 2557
FIRST EDITION, MARCH 1993

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American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005

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Measurement Coordination

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FOREWORD

This publication has been prepared to introduce vapor control technologies to individuals who are responsible for designing or purchasing vapor control devices for use on petroleum storage, transfer, and loading operations.

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Suggested revisions are invited and should be submitted to Measurement Coordination, Industry Services Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

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Vapor Collection and Control Options for Storage and Transfer Operations in the Petroleum Industry

SECTION 1—INTRODUCTION

1.1 Scope

Vapor collection and control, as it is discussed in this publication, includes the collection and treatment of volatile hydrocarbon vapors emitted during the storage and transfer of petroleum products and during loading operations. Passive vapor controls, which also can be effective at reducing emissions, are not covered in this publication. During loading operations, vapors from petroleum liquid will evaporate to reach equilibrium at ambient conditions to the degree allowed by the vapors' inherent vapor pressure. For example, vapors expelled while a rail car or truck is being filled with gasoline result from the exposure of hydrocarbon vapors to air and evaporation during transfer. Agitation of liquids and heating could cause additional vapor emissions during transfer operations. Vapor control devices collect emitted vapors and recover (for example, through refrigeration, absorption, or adsorption) or destroy (for example, by thermal or catalytic oxidation) them to prevent hydrocarbon vapors from releasing to the environment.

1.2 Purpose

This publication has been prepared to introduce vapor control technologies to individuals who are responsible for designing or purchasing vapor control devices for use on petroleum storage, transfer, and loading operations. The objectives of this publication are to acquaint readers with available vapor control technologies, provide general costing information, and supply a list of suggested reading for additional information on vapor emissions and control devices (see 8.2). Furthermore, vapor control technology checklists are provided in Appendix A to help readers effectively communicate their system needs to equipment vendors. The general issues that are discussed for each type of vapor control device include advantages and disadvantages; technical feasibility; and situational factors that affect applicability. Tank, truck, rail, and marine (ship and barge) loading operations are the specific applications discussed because these are the most common petroleum product transfer operations.

This publication is not intended to recommend specific vendors or to cover all aspects of vapor control technology. Each application must be analyzed individually. Using this publication as a guide, readers may discuss with vendors general aspects of each technology with minimum background research. Furthermore, since this publication will likely be used by individuals in many geographic and regulatory areas, regulations concerning vapor controls and vapor recovery should be consulted in addition to this publication. A thorough understanding of local, state, and federal regulations is essential before proceeding with the design, selection, or use of any pollution control device.

1.3 Definition of Vapor Collection and Control

Vapor collection and control includes the collection and treatment of emissions containing volatile organic compounds (VOCs). The objective of vapor control is to reduce the volume and/or concentration of vapors escaping to ambient air. This publication examines both the devices that collect vapors emitted during transfer or loading operations and emission abatement processes. Two emission abatement processes are discussed: a) recovery devices that remove vapors from gaseous streams and return the vapors as liquids for reuse and b) destruction (oxidation) devices that destroy vapors in gaseous streams.

It should be noted that in any emission reduction strategy, opportunities for minimizing emission generation should always be considered; however, vapor formation minimization techniques to reduce emissions from storage tanks are not addressed in this publication.

SECTION 2—APPLICATIONS OF VAPOR CONTROL

Three important applications of vapor control in the petroleum industry, in terms of the volume of vapor processed and number of installations, are storage tank vapor control, truck and rail terminal transfer vapor control, and marine terminal vapor control.

2.1 Storage Tank Vapor Control

The use of storage tanks is necessary in the production, refining, transportation, and distribution of petroleum products. Storage tanks are sources of evaporative emissions, which are usually calculated using API Publications 2517 [1] and 2519 [2] and MPMS Chapter 19, Section 1 (formerly API Publication 2518) [3]. Vapor control is most commonly applied to fixed cone or dome roof tanks without internal floating roofs. Fixed-roof tanks with internal floating roofs can accommodate vapor control technology, but this is less frequently done. Collection and treatment of vapors from internal floating roof tanks is generally less cost-effective because hydrocarbon vapor concentrations are significantly lower. Vapor control techniques are not typically applied to an external floating roof tank because the outer roof of the tank sits directly on the liquid surface and only a small internal vapor space is created around the rim seal; however, an external floating roof tank can be modified to accommodate vapor control by retrofitting the existing tank with a self-supporting fixed roof. Spherical tanks used for pressurized storage of liquefied petroleum gas generally have no evaporative losses.

Fixed-roof storage tanks are commonly used at refineries, pipeline tank farms, bulk plants, and transfer terminals for storage of low volatility liquids. Generally, each tank is equipped with a pressure-vacuum vent (P/V or conservation vent) valve designed to allow displaced air and vapor to escape during filling and to allow air or a vapor/air mixture to be introduced to the tank when product is being emptied. The vent prevents excessive pressures or vacuums from developing that could damage the tank. The design pressures of the tanks and all equipment must not be exceeded by the addition of a vapor collection system. Vapor emitted during filling is often referred to as the *working loss.*

Vapors can also escape from fixed-roof tanks when there is no product transfer activity. Daily temperature increases cause pressure buildup in a tank. Vapors are expelled through the P/V vent when pressure exceeds the setting on the vent valve, which is typically much less than 1 pound per square inch gauge. Pressure tolerance and vent valve setting vary depending on the tank design. Upon cooling, pressure can drop below the valve setting and air is introduced. Emissions that result from this process are often referred to as *breathing* or *standing loss.* In many cases, liquid stored in a fixed-roof tank has a low vapor pressure. The low hydrocarbon concentrations created by the low vapor pressure may not be cost effective to control.

2.1.1 INTERNAL FLOATING ROOFS

One approach to controlling evaporative emissions from fixed-roof tanks is to retrofit the existing tank with an internal floating roof. Internal floating roofs reduce evaporative storage losses by minimizing contact of petroleum products with air. The internal floating roof, or deck, is free to float on the surface of the stored liquid and rises or falls according to the height of the stored liquid. Rim seals are fitted to the edge of the floating roof where it meets the internal wall of the tank. Internal floating roofs can generally be installed inside existing fixed-roof tanks if the tanks are free of internal obstructions that would limit travel of the floating roof and do not contain thick or viscous material, such as heavy asphalt.

2.1.2 VAPOR CONTROL SYSTEMS

Using vapor control systems is another approach to controlling emissions from existing fixed-roof tanks. Vapor control can also be used on internal floating roof tanks. Because the emission rate of hydrocarbon vapor around rim seals in internal floating roofs is low, vapor concentrations for vapor control applied to internal floating roof tanks are much lower than concentrations for vapor control applied to fixed-roof tanks without internal floating roofs. With vapor control, vapors vented as working or breathing losses are removed through a piping system connected at or near the roof and are transported to a vapor recovery or destruction device.

Sometimes, several storage tanks containing similar products can be manifolded together and vented to a single vapor control system. Thus, one control device can service a number of storage tanks. This can be economical if tanks are filled at low rates. Sharing the control device may be impractical if operations allow simultaneous filling of tanks requiring a large vapor processor. If a vapor control system is used, manifolding the vapor space of several tanks can also equalize pressure buildup or decrease in the tanks. Economies of scale can be realized by installing one large unit rather than several small ones. Manifolded systems must be carefully designed to minimize the potential for explosion propagation through the system. Product contamination and explosive mixture formation can be issues if vapor spaces of dissimilar products are connected. The actual design of the vapor control system must consider many operations and safety aspects. Storage tank vapor control designs are uniquely applied from one facility to another.

The choice of applying vapor control versus retrofitting tanks with internal floating roofs is not a clear one, and many factors must be considered. Cost-effectiveness of vapor control increases if the vapor from several tanks can be processed by a single vapor control system. The cost-effectiveness of adding internal floating roofs as opposed to vapor control varies with the size of the tank, Reid vapor pressure (RVP) of stock, and number of turnovers. In general, larger diameter tanks can be controlled by vapor control more cost effectively than smaller tanks, but the economics governing use of vapor control versus retrofitting internal floating roofs vary enough that the economics must be evaluated on a case-by-case basis.

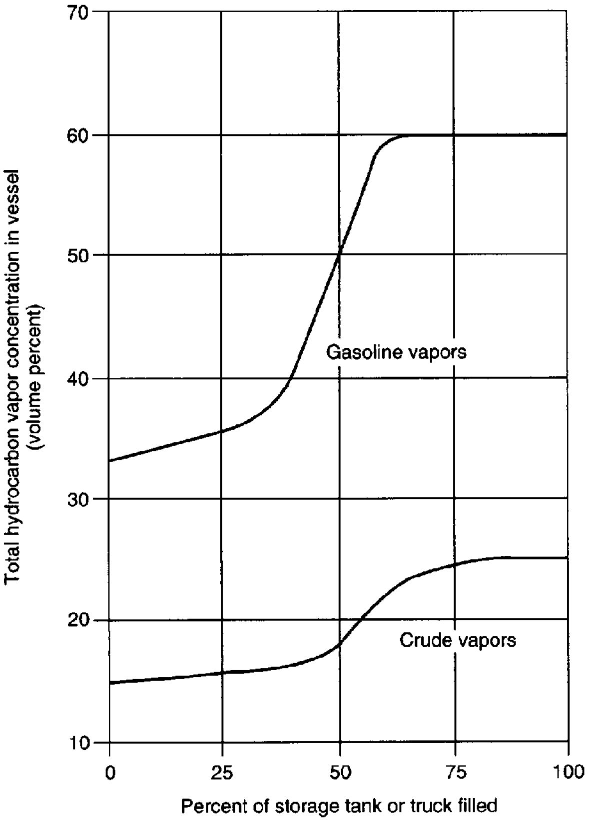


Figure 1—Storage Tank and Tank Truck Loading Hydrocarbon Concentration Profile

2.2 Truck and Rail Terminal Transfer Vapor Control

At bulk plants and transfer terminals, petroleum products are transferred into tank trucks and rail cars through metered loading racks. Finished products, such as gasoline and diesel, are generally transported by tank trucks; chemicals and intermediates are generally transported by rail cars. Loading racks can contain pumps, meters, piping, and movable loading arms with flexible hoses and check valves that connect to the delivery tank trucks. In addition, safety considerations require grounding, fire suppression equipment, and overfill alarms. A typical loading rack design has four to ten rack positions or bays. Since each rack position typically has three loading arms (each dedicated to one product), many loading arms are available for loading operations. Loading rack equipment does not vary significantly from small to large facilities; however, the number of loading positions increases.

The design loading rate of the nominal truck loading arm is about 650 gallons per minute (2,460 liters per minute). A truck loading, including hookup and disconnect, typically takes 10 to 20 minutes. During short peak periods of loading, all of the loading arms may be used simultaneously; however, standard use of the facility would be approximately two to four trucks at any given time.

2.2.1 LOADING METHODS

Without vapor control, emissions from truck and rail terminal transfer occur when the product being loaded displaces the vapors in the delivery vessel and forces the vapors to the atmosphere. The amount and hydrocarbon content of these emissions can be influenced by the loading method. Loading may be performed using the splash, submerged, or bottom fill method. In the splash method, the fill pipe dispenses the gasoline from the top of the truck and is only partially lowered into the cargo tank. Significant turbulence and air-liquid contact occurs during splash loading; this results in high levels of vapor generation and loss.

Loading product by using a fill pipe extended (submerged) inside the truck from the top to the bottom or loading product directly at the bottom of the truck reduces vapor generation. Most tank trucks are bottom loaded, and most rail cars are top loaded with the fill pipe extending to about 1 to 2 feet (0.3 to 0.6 meters) above the bottom of the tank. For both submerged loading methods, the fill pipe opening is below the liquid level during a majority of the loading time. The submerged loading method significantly reduces the liquid turbulence and air-liquid contact. Therefore, vapor emissions are reduced by 60 to 65 percent compared to splash loading [4]. In typical submerged fill gasoline loading operations, the vapor inside the tank truck contains about 30–60 percent hydrocarbon. Figure 1 shows an example of typical hydrocarbon concentration profiles for a storage tank or tank truck filling with either gasoline or crude. (Note that saturation levels of an actual profile will be largely dependent on RVP of stock and loading conditions.)

Tank trucks dedicated to a single service are generally not cleaned or vented between trips. An empty tank truck or rail car in dedicated gasoline service will retain a significant concentration of vapors generated by the evaporation of residual gasoline product. The vapors in the empty tank truck or rail car that arrives at the next transfer facility may be saturated with hydrocarbon. The saturation level will be greater for trucks that deliver to facilities employing vapor balancing. The residual vapors are expelled along with newly generated vapors during the subsequent loading operation.

2.2.2 VAPOR CONTROL

Vapor control at tank truck loading facilities is not a new concept. In 1990, approximately 70 percent of all bulk terminals in the United States had some type of vapor processor. In an operating vapor recovery system, the vapors

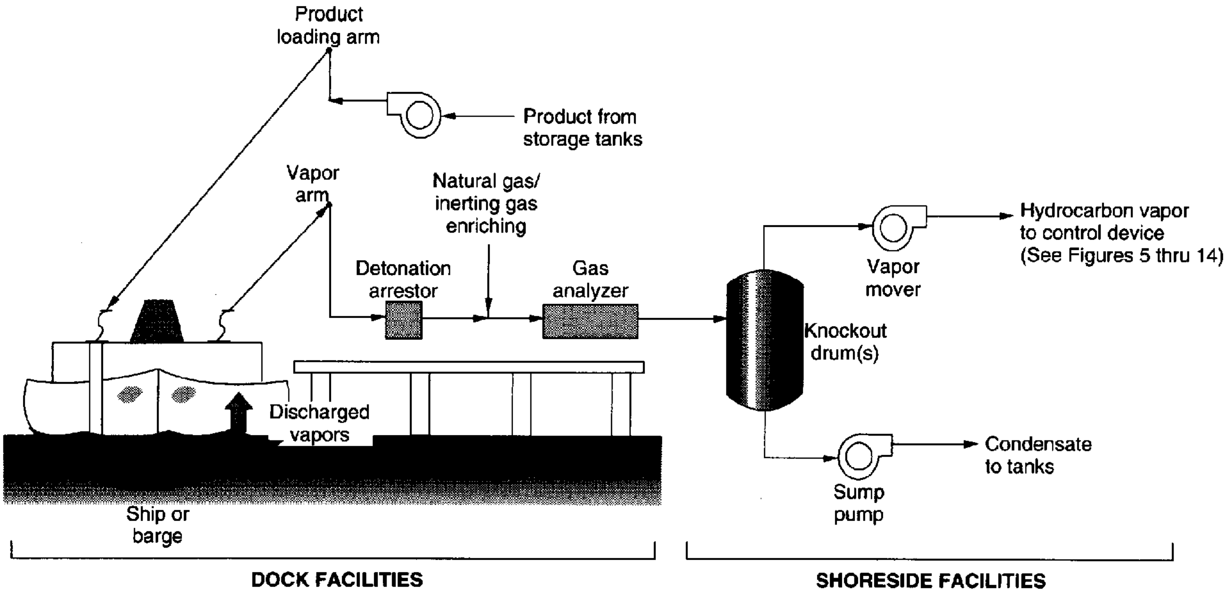


Figure 2—Typical Marine Vessel Loading System

displaced from the cargo tanks during loading are collected in a vapor header on the cargo carrier and returned to tanks being discharged (vapor balancing) or to a vapor recovery or destruction unit.

Vapor control has not been commonly applied at rail loading facilities mainly because gasoline is not generally loaded onto rail cars in the United States. Also, vapor recovery has not generally been applied to truck loading of diesel and heavier products. The low vapor pressure of such products produces a lower concentration of VOC, making recovery less effective. The vapors may also be potentially dangerous because they are not rich enough to exceed the upper explosive limit (UEL) and can be flammable.

2.3 Marine Terminal Vapor Control

Hydrocarbon vapors displaced from the cargo hold of marine vessels during vessel loading historically have been the largest single source of hydrocarbon emissions at storage terminals. Evaporative emissions from marine vessels are usually calculated using API Publication 2514A [5]. It is not uncommon to find that uncontrolled releases of hydrocarbon during gasoline loading onto a single ship or large barge can amount to as much as several tons of VOCs.

To collect and control the release of hydrocarbon vapors from marine loading activities, vessels must be designed or retrofitted to accommodate marine vapor collection. Ship safety is an important aspect of the design and implementation of a marine vapor recovery system. Regulations for marine system safety in the United States are the responsibility of the U.S. Coast Guard. Due to the international nature of the shipping industry, operating and safety concerns are also being addressed by the Oil Companies International Marine Forum (OCIMF) [6], and draft standards are proposed by the International Maritime Organization (IMO) [7]. Shipboard equipment required by the U.S. Coast Guard includes vapor collection piping and manifold connections (vapor header) that join the vapor space of all vessel cargo compartments. On some ships, the inert gas system header may serve as an appropriate vapor header.

In addition, all open vents or manholes on ships or barges must be sealed off to allow closed loading and prevent escape of cargo vapors. This in turn requires certain safety precautions, such as remote tank gauging and overfill alarms, because the product level in the vessel can no longer be viewed directly. Of primary concern for the safety of the ship is protection against overpressuring or underpressuring the vessel. To protect against overpressuring or underpressuring, P/V valves must be installed in vent lines or on individual vessel tanks.

Shipdock and shoreside components of a marine vapor recovery system are shown in Figure 2. Vapor from the ship's compartments is either displaced under slight positive pressure by the rising product in the vessel or evacuated under a vacuum created by a shoreside vapor mover, which can be either a vacuum pump, blower, or fan. A movable vapor collection hose or vapor arm is attached to the ship's vapor manifold to carry the vapors to the dock. On the dock, the U.S. Coast Guard requires detonation arrestors; hydrocarbon or oxygen analyzers; and vapor enriching, inerting, or diluting systems in the vapor piping for fire safety [8]. Sufficient controls must be installed to shut down the system if the hydrocarbon and oxygen mixture falls within the flammable range.

According to U.S. Coast Guard requirements, diluting systems must keep the hydrocarbon concentration below 30 percent of the lower explosive limit (LEL) and enriching systems must maintain hydrocarbon levels above 170 percent of the upper explosive limit (UEL). Enrichment gas is usually propane or natural gas, inerting gas is usually nitrogen, and diluting gas is usually air.

When ships or barges arrive at a terminal, they are virtually empty and contain primarily air or inerting gas. Hydrocarbon vapor may remain from the previous cargo. Hydrocarbon vapors evolve during loading due to a tendency toward saturating the air (a phenomenon called vapor growth) and due to the turbulence of the loading operation. Since hydrocarbon vapors are heavier than air, they tend to stratify in the vessel and rest in a vapor layer just above the liquid. For most of the vessel loading, very lean vapor is collected until the concentrated vapor layer is reached at the end of the loading cycle. The hydrocarbon content of the vapor at the end of the loading cycle ranges from 1 percent for low RVP crudes to 60–70 percent for gasoline and other volatile petroleum products. Figure 3 shows the hydrocarbon profiles for typical gasoline and crude loading on a marine vessel.

During loading of a marine vessel, the vessel loading rate initially is very low for a short period while the process is monitored and connections and operations are checked; then, the rate is increased to the maximum loading rate for the remainder of loading. At the very end of the loading, the rate is slowed to prevent overfill of the vessel. For the majority of the vessel loading process, vapors are generated at a relatively constant rate. The duration of actual loading and vapor collection activities can range from less than an hour for filling very small barges to over 24 hours for filling large ocean-going oil tankers.

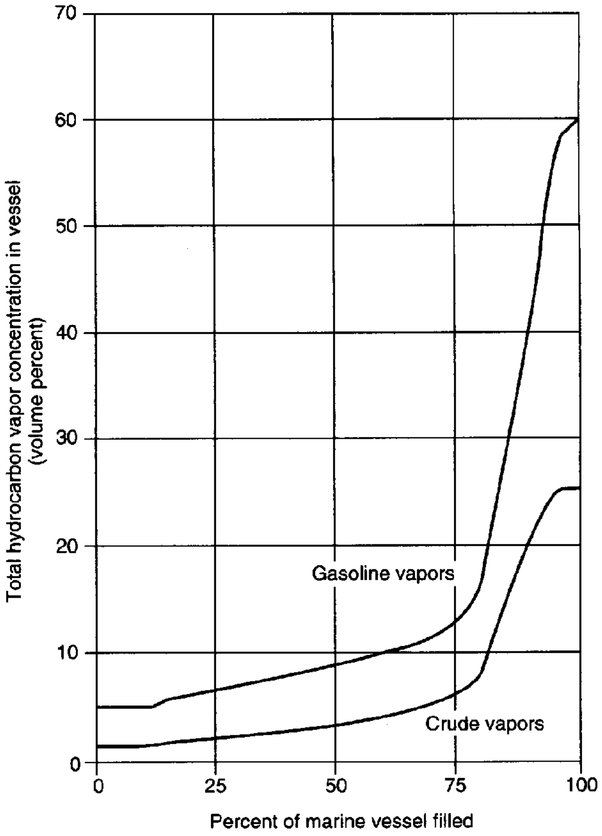


Figure 3—Marine Vessel Loading Hydrocarbon Concentration Profile

SECTION 3—VAPOR COLLECTION SYSTEMS

Vapor collection systems collect vapors that are vented from tanks or vessels during transfer operations and from routine tank breathing. The collection system consists of connections to the tank or vessel at one end and piping to the eventual vapor control device. At loading facilities, flexible hoses or a movable piping extension referred to as a "vapor arm" (loading arm) is used to position the vapor collection piping at the proper venting location. Liquid loading arms at facilities may be able to be converted to vapor service when vapor recovery is installed if a spare arm is available at each loading station.

Vapor collection systems can be simple and consist of only piping and connections, or the systems can be complicated by the addition of equipment for safety (for example, shutoff valves and detonation arrestors), additional motive force, and/or vapor pretreatment (for example, vapor enrichment). Vapor collection systems are custom-designed to provide optimum operational flexibility and safety, so there are many variations. Paragraphs 3.1 and 3.2 describe two vapor collection techniques, vapor balancing and vacuum-assisted vapor collection, and issues regarding the use of the techniques.

3.1 Vapor Balancing

In vapor-balanced systems, displaced vapors are returned to the liquid storage tank that is being emptied or are temporarily stored in a separate vapor holding tank called a bladder tank. Vapor balancing is most commonly applied to fixed-roof storage tanks and tank trucks. Figure 4 shows a schematic drawing of a vapor-balanced truck loading system. Vapor balancing allows displaced, saturated hydrocarbon vapors to fill vapor space in tanks or tank trucks that would have otherwise been filled by air. This reduces product evaporation loss and can prevent formation of flammable vapor over volatile products. Vapor balancing has also been included in vapor control systems that must respond immediately to high vapor processing rates for short periods of time, followed by long periods of shutdown. Systems requiring such start-stop operations are more difficult to design than steady-state systems. Wear and tear on the equipment is exaggerated in start-stop operations. To avoid these problems, some vapor control systems have included vapor balancing.

One benefit of using vapor-balanced systems is that the vapors can be processed later at continuous, steady-state conditions and at a controlled rate. For loading operations, this has several advantages. Vapors can be processed at a much lower rate than the fill rate of a tank, truck, or vessel, which allows for equipment and piping downsizing. Also, the product loading process and vapor processing steps are separated, which allows for more flexibility in operations. In a non-vapor-balanced system, trouble with a vapor processing device such as a carbon adsorber or thermal oxidizer might cause delays in product loading and influence delivery schedules.

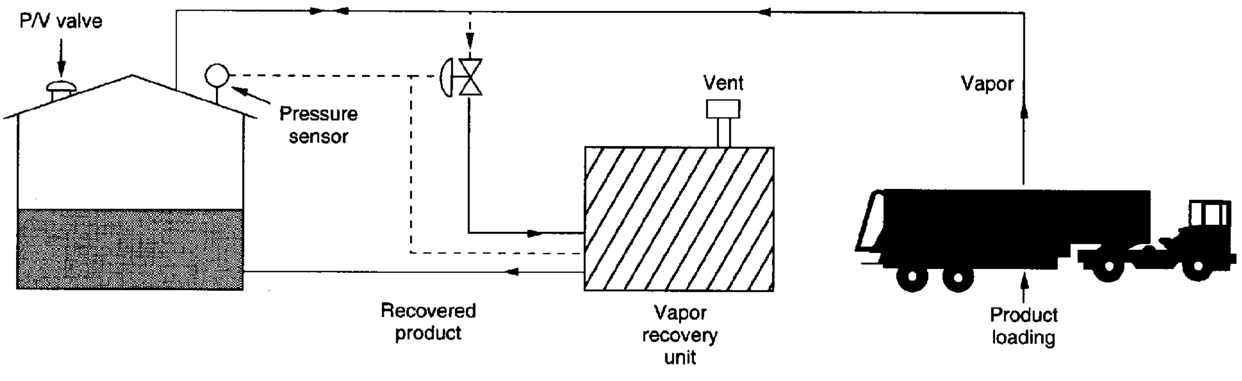
In tank farm systems, vapor balancing can be accomplished by interconnecting the vapor space of tanks containing similar products in a piping manifold so that vapor can be exchanged for product when moved between tanks. Also, the diurnal pressure buildup from daily heating and cooling can be more equitably shared. This would eliminate frequent small volume pressure releases from each individual tank and allow for one-time processing of tank breathing vapors.

Although there are advantages to operations if vapor balancing is installed (as a retrofit), tank modifications can be expensive. Also, extra piping and manifolding to the tank farm (instead of a direct route to the vapor control device) might be required. Proximity of the loading equipment to storage tanks is the principal factor in determining whether vapor balancing is feasible. The piping required to return vapors to the storage tanks can be very costly.

The vapor-balanced system is most effective when transfer takes place between tanks with vapors already present (tank to tank or tank to truck). Vapor balancing is not possible when tanks are being filled from sources that do not have vapor spaces, such as pipelines. When a tank containing unsaturated air is being filled, the potential exists for vapor growth or new vapor formation to saturate the air. The amount of vapor growth depends upon temperature and turbulence during filling; up to 10 percent growth is not uncommon in transfer operations to vessels containing unsaturated air. Reusing already saturated air minimizes vapor growth. Vapor balancing is based on the principle that the vapor volume equals the liquid volume displaced (a 1:1 volume transfer of liquid for vapors) and therefore does not allow for vapor growth.

If the collected vapor mixture is flammable, safety can be a concern because the stream's hydrocarbon concentration cannot be adjusted if vapor balancing is used. The addition of inerting, diluting, or enriching gas would increase the overall vapor volume to greater than the displaced liquid volume and require direct processing. Thus, vapors with potentially flammable concentrations of hydrocarbons up to 20 percent would have to be safely transported and stored.

Bladder tanks are tanks with an expandable vapor holder that are used on rare occasions in vapor control and vapor balancing designs. They can even out surge flows, provide capacity for vapor growth, and save a reserve of vapors to return to the tanks during in-breathing modes. Bladder tanks are only cost-effective for small truck loading facilities be-



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Guidelines for the Design and Operation of Gasoline Vapor Emission Controls

Figure 4—Vapor Balancing System

cause generally the tanks can only hold a small volume of vapors (30,000 cubic feet or 850 cubic meters or less). They also have high capital costs and a relatively short life span. If installed as a retrofit, the steel tanks must be specially adapted for smooth corners, inlet openings, removal of obstructions, and points of attachment to allow for inflation of the bladder.

3.2 Vacuum–Assisted Vapor Collection Systems

In vacuum-assisted systems, the collection system includes a blower, fan, or vacuum pump that provides a motive force to pull vapors from the tank or vessel being filled. Introducing a vacuum-assist device into the vapor collection system creates an active collection system, which allows control over the vapor flow rate. Systems that do not use vacuum producing equipment to pull the vapors rely upon the liquid to move the vapors passively by displacing them. Passive vapor collection systems are found frequently in applications where vapors are transported for short distances and are found in most vapor balancing systems (described in 3.1).

A vacuum-assist device must be used in situations where the vapor transfer piping or equipment in the vapor piping network imposes pressure drops larger than can be tolerated by the vessel being filled. The tendency to experience large pressure drops can be aggravated by long distances, small piping diameters, restrictions or orifices, blockage in detonation arrestors, and condensation or blockage in piping. If pressure drop in the vapor collection system exceeds design, flow of displaced vapors can be restricted and cause backpressure on the vessel being filled. Most marine vessels cannot tolerate more than about 1 pound per square inch gauge (6.8 kilopascals) of backpressure. P/V vent valves on ships are generally set at less than 1 pound per square inch gauge (6.8 kilopascals) and will open if the vent pressure is exceeded so that vapors are discharged to atmosphere and not discharged through the vapor collection system. Fixed-roof tanks also have safety relief valves designed to handle overpressure related to vent valve failure or overfilling.

The use of a vacuum-assist device allows for the evacuation of vapor lines when product transfer is completed, so vapor loss and emissions are prevented. This is important in truck and marine loading applications where the vapor lines are disconnected when loading is completed; however, this is not an issue if the collection system is permanently installed, as in the case of a system used to collect tank farm vapors. When there is no means to pull vapors from the line or sufficiently cap the connection, such as with self-sealing couplings, vapor contained in the collection line is released upon disconnection. This may be important if a material that has Occupational Safety and Health Administration (OSHA) limitations on workplace exposure is being transferred or loaded.

The equipment cost for a vacuum-assist blower package can add $100,000 to $300,000 or more to the price of a collection system, depending on the size and type of blower, fan, or vacuum pump required [9]. Also, installation and operating costs can be high because these devices require power and sometimes reinforced supports, enclosures, and extra instrumentation. In addition, these devices can be very noisy.

Vacuum-assist devices tend to make collection systems safer with regard to overpressurization, but the devices may introduce safety hazards. If a vacuum-assist device is not regulated to the vapor generation rate, it can pull an excess of air into the vessel and vapor collection system, thus potentially creating a flammable vapor/air mixture. For collection systems that transport vapor and air mixtures within their flammability limits, these devices also present a potential source of spark initiation. The U.S. Coast Guard requires that most vacuum-assist devices in marine vapor collection systems have additional detonation arrestors.

SECTION 4—VAPOR RECOVERY PROCESSES

Vapor recovery processes control releases of hydrocarbons and recover the hydrocarbons that can be subsequently recycled, reused, or sold. When vapor recovery processes are applied to gasoline loading operations, the amount of product recovery is typically about 1 gallon per 1,000 gallons loaded [10]. This amount would be much less for products of lower volatility, such as crude. In addition to the advantage of product recovery, these processes are also desirable over vapor destruction because no combustion by-products are generated. Three common vapor recovery processes are described in this section: carbon adsorption, lean oil absorption, and refrigeration. A comparison of vapor recovery processes is presented in Table 1. A comparison of typical costs for recovery processes is given in Table 2. Guidance on sizing of carbon adsorption and refrigeration VOC control systems and estimating their cost is available in the U.S. Environmental Protection Agency's *OAQPS Control Cost Manual* [11], W. Vatavuk's "Pricing Equipment for Air Pollution Control" [12], and R. S. Hall's "Estimating Process Equipment Costs" [13].

Vapor recovery can be used when a facility is space limited because vapor recovery devices can be located close to the vessel, whereas vapor destruction devices must usually be located at least 100 feet (30 meters) from the tank or vessel as a safety precaution. Vapor recovery may be more difficult to apply to some vapor streams, such as crude-oil

Table 1—Vapor Recovery Process Comparison

Common Applications	VOC Control Efficiency	Waste Streams	Technical Concerns	Operating Concerns	Maintenance	Safety	Instrumentation and Control	Utilities
Refrigeration								
Tanks and truck loading facilities. High value products with few light components	50–95% (can readily achieve up to 90% removal at very low temperatures for heavier components)	Chiller condensate may be contaminated with H_2S and hydrocarbons	System is complex and will require intensive training. Frost buildup must be prevented. Loss of refrigerant	Complicated system requiring skilled technician. Not appropriate for products with high freeze temperatures	Refrigeration compression systems require high degree of maintenance	Relatively Safe. Design for flammable vapors could be costly	Logic controller with complex temperature, pressure, and flow controls. Highly automated system	Power for compressor, condenser, precoolers, and blowers. High energy draw for lower temperatures
Carbon Adsorption								
Tanks, truck loading, and marine loading of pure products such as gasoline and benzene. Not typically used on crude	Up to 99% (questionable for vapors with high % of propane or lighter compounds). Depends on type and amount of carbon	Spent carbon. Wastewater from condensed water vapor	H_2S, heavy organics, and other impurities foul carbon bed	Some carbon systems require a steady inlet flow rate. Temperature excursions from exposure to contaminants or introducing air	Vacuum pump requires high degree of maintenance. Bed life is 5–10 years, depending on maintenance history and loading	Relatively passive system	Logic controller and control panel with cycle timers and temperature, pressure, and flow controls	Power for vacuum pump and/or steam for regeneration cycle
Lean Oil Absorption								
Tanks and truck loading of gasoline or other highly volatile products. Commonly used in combination with adsorption or destruction processes	50–95% depending on vapor type and solvent. Difficult to get high removal with low inlet vapor concentrations < 10% VOC	Reprocessing can generate a water stream contaminated with H_2S and hydrocarbons	Requires local source of large volumes for absorbent—best suited to refinery or gasoline storage terminals	Circulation and vapor turndown must be 4:1. Relatively simple operation	Low maintenance. Packing trays require cleaning	Relatively passive system	Logic controller and control panel with temperature, pressure, and flow controls	Power for lean oil recirculation pumps and regeneration cycle (reheat and chiller units)

Table 2—Vapor Recovery System Cost Estimates[a] (Thousand U.S. Dollars, 1990)

	Vapor Recovery Process		
Cost Type	Carbon Adsorption	Lean Oil Absorption	Refrigeration
Equipment Capital Cost[b]	220–850	175–700	250–1,250
Processing Unit Installed Cost[c]	1,000–2,500	1,000–1,750	1,500–3,000
Annual Operating Costs[d]	40–60[e]	75–100	85–150
Annual Recovered Product (Gasoline, 1 gallon per 1,000 gallons)[f]	220	220	220

[a] Based on a process sized for a maximum vapor rate of 936 standard cubic feet per minute (10,000 barrels per hour or 7,000 gallons per minute).

[b] Ranges supplied and verified by vendors. Represent differences in design for units of similar size.

[c] Ranges supplied and verified by vendors. Costs include grading, foundations, power connection and transformer, labor, rigging, freight, auxiliary equipment and instrumentation, and other installation costs. Some costs are compared in J. W. Young's "Vapor Control: Recovery and Destruction" [9] and *OAQPS Control Cost Manual* [11]. Does not include costs for necessary infrastructure, such as vapor arms, piping, and electrical. Ranges represent differences in location-specific resources and complexity of system. Costs can be greater if custom specifications from the purchaser are to be incorporated.

[d] Based on an average rate of 7.5 million standard cubic feet per day (1 million gallons per day) and 750 hours per year of actual operation. Costs include electrical (at $0.05 per kilowatt hour) and operating and maintenance (at a labor rate of $20 per hour). Ranges supplied by vendors and "Vapor Control: Recovery and Destruction," "Gasoline Marketing Industry (Stage I)—Background Information for Proposed Standards"[10], *OAQPS Control Cost Manual*, and J. Hill's "Controlling Emissions from Marine Loading Operations" [14]. Does not include capital recovery.

[e] Assumes replacement of 25,000 pounds of activated carbon every 10 years. Cost of carbon assumed to be $2.09 per pound.

[f] Based on typical vendor estimate for vapor recovery systems, in general, achieving recovery of 1 gallon per 1000 gallons gasoline loaded and price of $0.60 for recovered gasoline.

vapors or those containing ketones, aldehydes, organic acids, or hydrogen sulfide (H_2S). Also, the equipment capital cost is usually higher for vapor recovery than for vapor destruction; however, recovery of large amounts of product with a high monetary value could make vapor recovery competitive with vapor destruction.

4.1 Carbon Adsorption

Vapor recovery by carbon adsorption is a process where hydrocarbon vapors are collected on activated carbon. Intermolecular forces attract and hold the gas molecules to the solid surface. Activated carbon is very porous and has a very large surface area-to-volume ratio. Hydrocarbons penetrate the pores of the adsorbent and once inside the carbon are adsorbed exothermically within the carbon.

Figure 5 shows a typical carbon adsorption vapor recovery system. A carbon adsorption system usually consists of two or more simultaneously activated carbon vessels. Carbon bed depth is typically 6 to 10 feet (1.8 to 3 meters), and gas velocity at the face of the bed is typically 10 to 30 feet per minute (3 to 9 meters per minute). Increasing the velocity or bed depth will increase the pressure drop across the adsorption bed. While one carbon adsorption vessel accepts and treats hydrocarbon emissions, a second vessel is regenerated. Hydrocarbon analyzers are sometimes used between beds to identify hydrocarbon breakthrough and the need for regeneration. When used for petroleum vapor processing, carbon adsorption systems are applied alone or are commonly teamed with an upstream absorption step, as described further in 6.1.

Carbon regeneration uses vacuum to desorb hydrocarbon vapors from the carbon bed or heat (in the form of low-pressure steam) to recover the vapors. The concentrated desorbed vapors are then condensed and pumped back into the product tanks. Regeneration can be performed at lower pressures, causing the hydrocarbons to be desorbed back into the vapor phase. Regeneration of the carbon bed can also be performed at temperatures greater than 300°F (149°C), where the intermolecular forces are weakened and the hydrocarbons are released from the carbon surface. The carbon can be regenerated many times but must eventually be replaced due to fouling and decrepitation (typically after 10 years). Carbon bed adsorption/regeneration cycle times range from 15 minutes to several hours depending upon vapor inlet and required outlet concentrations. A typical cycle time is 2 hours. Carbon adsorption can commonly achieve vapor recovery efficiencies of up to 95 percent. Some operating facilities have documented pure product recovery efficiencies as high as 99 percent. High removal efficiencies can be obtained by increasing the amount of carbon used in the treatment unit and using more beds; however, the recovery efficiency achieved depends on the chemical characteristics of the VOCs in the emission stream. In general, low molecular weight compounds such as methane, ethane, propane, and butane are too weakly adsorbed for carbon to be effectively used in their recovery. The concentrations of very light compounds in gasoline or other petroleum vapors have an influence on the overall removal efficiency. Other inlet stream characteristics (temperature, pressure, and flow rate), the physical properties of the carbon (type, granule size, and porosity), and the degree of bed regeneration also affect the recovery efficiency.

One advantage of carbon adsorption is that it is effective in treating lean concentration streams. Also, adsorption devices exhibit relatively low energy consumption and have demonstrated performance for petroleum loading and transfer operations. The primary advantage of carbon adsorption is its ability to recover usable product.

The most significant limitation of carbon adsorption is its inability to process certain compounds. Aldehydes, ketones, and other reactive compounds may result in temperature excursions or the development of "hot spots" in the carbon bed. This is due to exothermic reaction on the carbon surface that causes heat to build up inside the carbon bed. Hydrogen sulfide (from crude-oil vapors) forms elemental sulfur in the presence of oxygen and water, which poisons the carbon beds and restricts flow. Therefore, carbon adsorption is used most often in pure hydrocarbon product transfer/storage (that is, gasoline, benzene, or other products with constant qualities or specifications) and less frequently in crude-oil operations.

It is difficult to desorb VOCs with a boiling point greater than 400°F (204°C) or a molecular weight greater than 130. Such compounds could be present in petroleum product vapor streams as aerosols. Processing VOCs with these chemical characteristics will result in a lower recovery efficiency and short bed life. For streams with a VOC concentration less than 1 percent by volume, a low moisture content is essential because water vapor competes with the VOCs for adsorption sites on the activated carbon. In general, carbon beds should operate during the adsorption mode at less than 130°F (54°C) and 50-percent relative humidity.

In addition, carbon adsorption systems may not be well suited for emission streams with highly fluctuating inlet concentrations, depending on how the bed is operated. Carbon

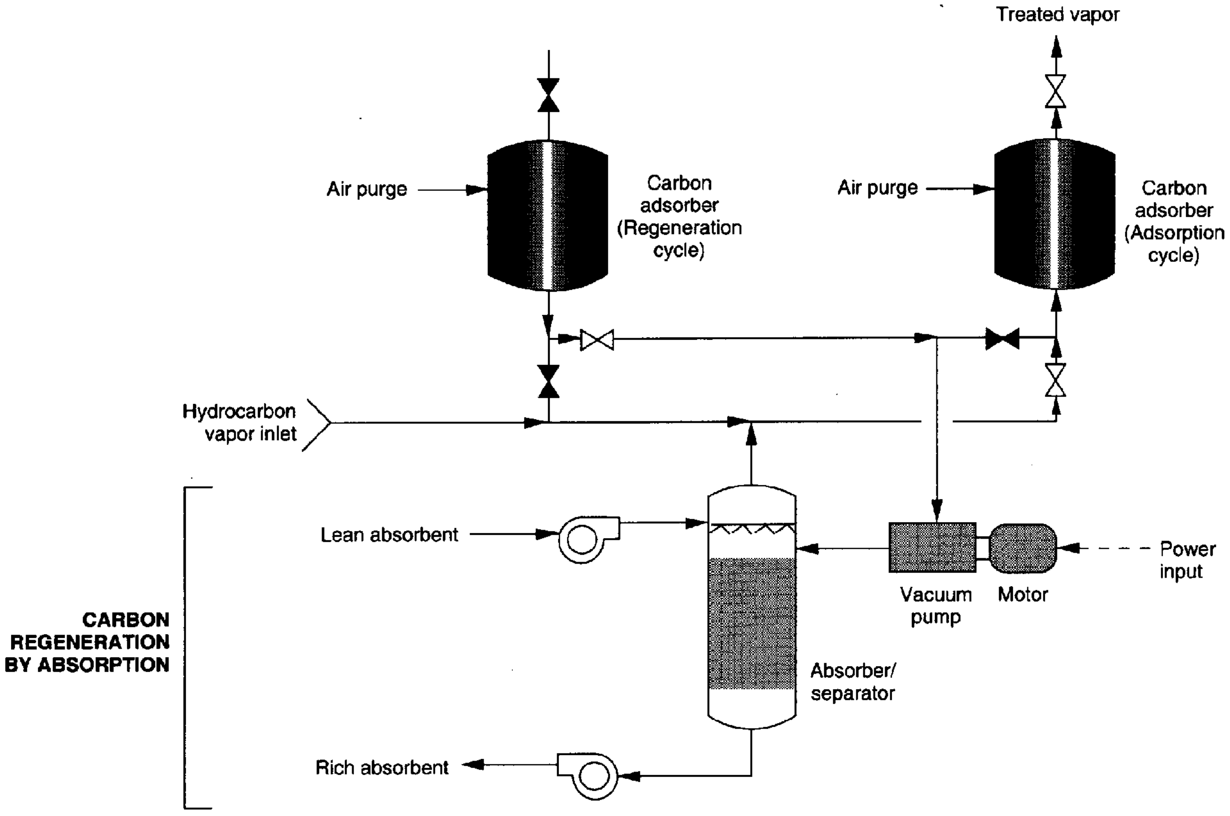
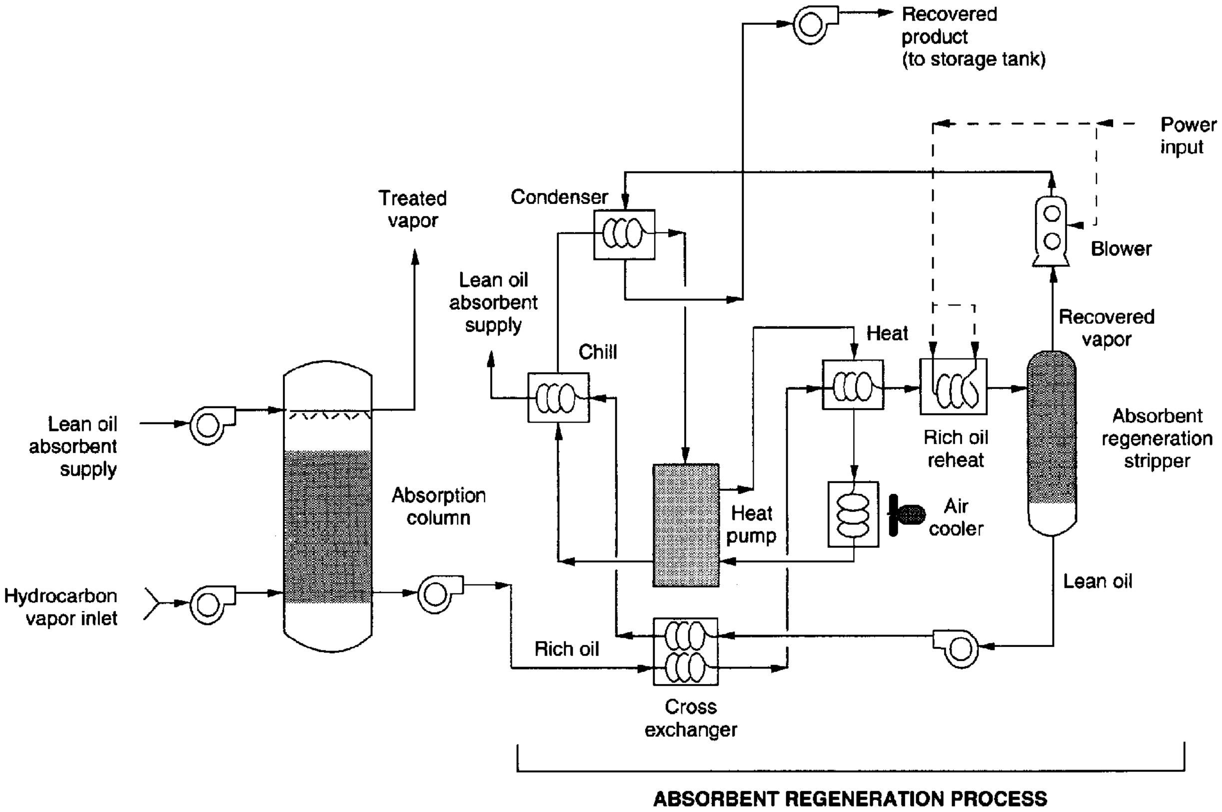


Figure 5—Typical Carbon Adsorption Vapor Recovery System



Note: Power is also supplied to all circulation pumps.

Figure 6—Typical Lean Oil Absorption Vapor Recovery System

adsorption systems are best suited for emission streams with constant flow and moderate concentration swings.

The installed cost of carbon adsorption systems is most directly affected by the flow rate of the emission stream and the adsorption potential of the VOC. The flow rate will, for the most part, determine the size of adsorption vessel that will be required. Operating costs associated with carbon adsorption systems include power for fans and pumps in the system, steam for carbon regeneration (if used), and replacement of the carbon, on the average, every 5 to 10 years. Occurrence of excessive bed fouling or temperature excursions could reduce bed life.

If steam is used to regenerate the carbon, water contaminated with hydrocarbons would be produced. This may result in additional operating costs for wastewater disposal. If the recovered hydrocarbons are not usable, their disposal cost should also be considered with system operating costs.

4.2 Lean Oil Absorption

Lean oil absorption has some unique applications in vapor recovery systems. Because lean oil absorption of typical petroleum hydrocarbon vapors is less efficient than some of the other recovery processes, it is rarely applied alone. Lean oil absorption is most commonly applied as a preconditioning step for bulk recovery of hydrocarbon vapor and is followed by either another recovery step, such as carbon adsorption (see 6.1), or a combustion polishing step.

Absorption is the selective transfer of one or more components of a gas mixture into a lean liquid solvent. The equilibrium ratio (K value), the ratio of the solute (VOC) concentration in the gas to the solute concentration in the lean solvent, is the driving force for absorption. Spray towers, venturi and wet impingement scrubbers, and packed towers and plate or bubble cap columns are all examples of absorbers. Packed or plate columns are typically used for VOC control by gas absorption. Figure 6 shows a typical lean oil absorption vapor recovery system.

Packed towers use inert packing, such as porcelain, metal, or plastic, to provide surface area for liquid/gas contact. Packed towers are commonly used for corrosive materials or liquids that tend to foam or foul plate towers. Plate/tray columns are preferred for large-scale operations and for low liquid flows that would not adequately wet the packing.

The recovery efficiency for lean oil absorption is highly dependent on the solvent used (must exhibit high solubility for the specific VOCs in the stream) and the column design. The recovery efficiency generally can be improved by increasing the contact surface area or absorber size, increasing the number of contact stages, refrigerating the lean oil, pressurizing the returned vapors, or increasing sorbent circulation. These improvements add cost and/or complexity. Hydrocarbon recovery efficiencies range from 50 to 95 percent for lean oil absorption. The efficiency depends on the vapor concentration and solubility of the vapor in the lean oil. Under typical conditions, gasoline and crude-oil vapors can be absorbed with 75- to 85-percent efficiency [8]. Refrigerating the absorbent [down to –32°F (–25°C)] can increase the recovery efficiency to 95 percent.

The primary advantage of absorption is that it can tolerate chemical variability, even the variability found in crude-oil vapors. Absorption also can accommodate variability in vapor flow rate (generally allows a 4:1 turndown) and hydrocarbon concentration. In addition, lean oil absorption is considered to be relatively safe.

The applicability of absorption is limited by the availability of a suitable solvent for the VOCs in the process stream. Absorption is also limited not only by the absorptive capability but also by the subsequent regeneration of the VOCs from the solvent for final recovery. Typically, absorption is used for streams with a VOC concentration of at least 2,000–3,000 parts per million by volume. In fact, absorption systems could increase emissions during very lean vapor periods. High absorption pressures [up to 500 pounds per square inch (3,447 kilopascals)] may be required to meet the overall emission-reduction limits of combined rich and lean periods.

Equipment costs associated with lean oil absorption systems are directly related to emission-stream flow rate. The size of absorption tower required and the flow rate of absorbing fluid (lean oil) are also directly related to emission-stream flow rate. One operating cost for a lean oil absorption system is the power required to pump fluids and to drive blowers, chillers, and auxiliary heat exchangers. Lean oil absorbers can be obtained as package units with all pumps, heat exchangers, and support equipment.

4.3 Refrigeration

Vapors containing VOCs can be condensed by increasing the pressure or lowering the temperature of the system. Hydrocarbon vapors from petroleum product transfer operations are commonly chilled at atmospheric pressures with refrigerants that separate the vapors from the residual air. More volatile hydrocarbons (propanes and lighter) require a lower temperature and possibly higher pressure to saturate and condense the vapors.

Auxiliary equipment required for condensation often includes a precooler to remove moisture before the vent stream enters the condenser. Moisture is removed to avoid ice buildup. In addition, a storage tank, a pump/blower, and piping are needed to transfer the recovered product back into the product stream. Figure 7 shows a typical refrigeration vapor recovery system.

A recovery efficiency of greater than 90 percent can be achieved with refrigeration for low vapor pressure hydrocarbons. Recovery efficiencies range from 50 to 95 percent and are dependent on the volumetric flow rate of the vent gas stream; the vent stream properties (temperature, pressure, VOC concentration, and moisture content); and the VOC chemical properties, such as dew points, heat capacities, and vapor pressures [10].

The primary advantage of refrigeration is that it produces a high-purity recovered product that can often be directly recycled into the product stream and sold without any further processing. In addition, the stand-alone refrigeration unit does not need circulating lean oil or absorption fluid, and no combustion products or waste (from spent carbon or spent absorbing fluid) is generated. The only waste stream is a relatively small amount of precooler condensate. Also, refrigeration can often handle chemicals that prove troublesome to desorb from carbon or that cause temperature excursions on activated carbon systems.

Refrigeration is safe because vapor streams are simply passed over a cold metal surface to condense the vapors; however, for vapor streams that are flammable, compressors and pumps may provide ignition sources that require additional safety measures in equipment design. Although such safety measures have been successfully implemented and demonstrated, they can increase equipment costs.

Disadvantages of refrigeration are the high energy consumption and associated cost required for the cooling of the total gas stream. The temperature required to achieve a 90 to 95 percent recovery efficiency is in the range of –100 to –200°F (–73 to –128°C). To attain these low temperatures, a cascade system and the use of more than one coolant are usually required. Another disadvantage of refrigeration is the substantial maintenance requirement. Personnel must be properly trained to maintain the refrigeration compressors and to defrost the refrigeration system, as necessary.

The applicability of refrigeration is typically limited to streams with VOC concentrations less than 0.5 percent by volume and low moisture content. Precondensers are sometimes used for streams with higher moisture content. Refrigeration units are usually used to process gas streams with a flow rate up to 2000 standard cubic feet per minute (944 dry cubic meters per second). At greater flow rates, the surface area needed for sufficient heat transfer results in a prohibitively large and costly condenser.

The parameters affecting the cost of refrigeration systems are the required condensation temperature, heat load (refrigeration tonnage), and volumetric flow of the emission stream. Packaged systems can be supplied that include the refrigeration unit with the necessary pumps, compressors, condensers/evaporators, coolant reservoirs, VOC condenser unit and recovery tank, precooler, instrumentation and controls, and piping. The most significant operating costs are associated with the power draw to run the refrigerant compressor and system pumps.

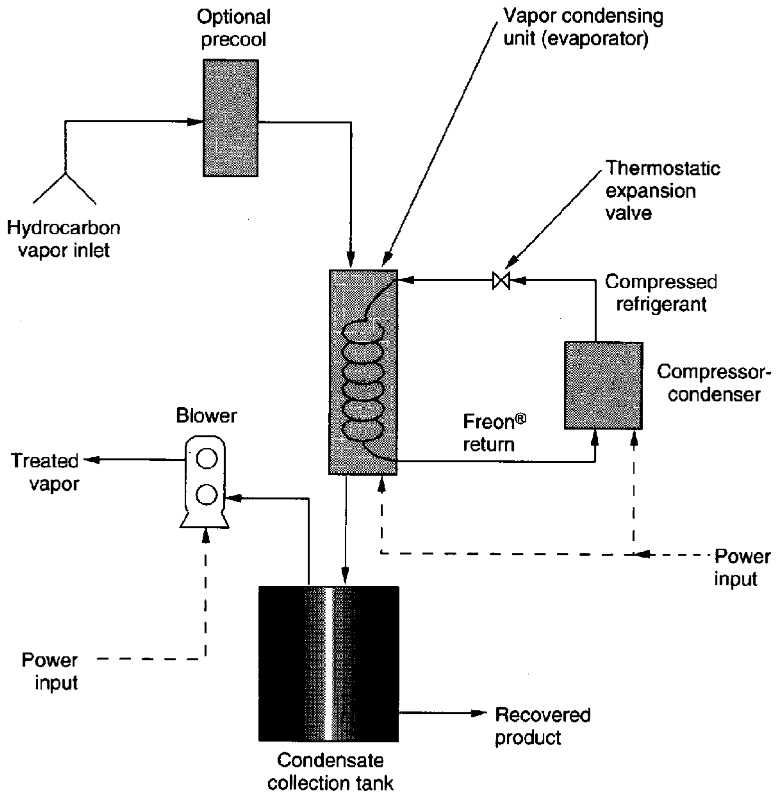


Figure 7—Typical Refrigeration Vapor Recovery System

When refrigeration systems are specified or purchased, the cost of coolant (heat transfer fluid) is usually not included in the packaged system cost. Selection of refrigerant should be given careful consideration, especially since the use of chlorofluorocarbon refrigerants is being phased-out. The cost of purchasing refrigerants and disposing of used refrigerants must also be considered in the system operating costs. If the condensed stream contains many contaminants and cannot be reused, costs to dispose of the recovered liquid may add to the operating costs. Also, condensed moisture from the precooler or condenser is likely to contain contaminants and must be disposed of properly.

SECTION 5—VAPOR DESTRUCTION PROCESSES

This section describes three processes that control vapor emissions by destroying collected vapors to prevent release to the environment. These three processes are thermal oxidation—flares, thermal oxidation—incineration, and catalytic oxidation. A comparison of vapor destruction processes is presented in Table 3. Costs for the most commonly used systems, open and enclosed flares, are compared in Table 4. Guidance on sizing of VOC control equipment and estimating its cost is available in the U.S. Environmental Protection Agency's *OAQPS Control Cost Manual*, W. Vatavuk's "Pricing Equipment for Air Pollution Control," and R. S. Hall's "Estimating Process Equipment Costs."

5.1 Thermal Oxidation—Flares

Thermal oxidation or flaring is a combustion control process in which VOCs are piped to a remote, usually elevated, location and burned in an open or enclosed flame. Flares use specially designed burner tips, auxiliary fuel, and steam or air assistance to promote mixing for smokeless combustion. Completeness of combustion in a flare is governed by flame temperature, residence time, turbulent mixing, and available oxygen.

The primary advantage of flares is that they can achieve very high destruction efficiencies (greater than 98 percent) for total VOCs and most individual hydrocarbon species. Flares can be used to control almost any flammable VOC stream and can handle fluctuations in VOC concentration, flow rate, heating value, and impurities (for example, sulfur). Flares are frequently applied to control crude vapor emissions.

Flares are generally categorized as either elevated open flares or enclosed ground flares. The difference between

Table 3—Vapor Destruction Process Comparison

Common Applications	VOC Control Efficiency	Waste Streams	Technical Concerns	Operating Concerns	Maintenance	Safety	Instrumentation and Control	Utilities
Enclosed Flare								
Most versatile control option. Numerous applications to tank, truck, and marine vapor control	>98%	Produces NO_x, SO_2, CO, and sometimes smoke (hydrocarbon + particulates)	Radiant heat generation at ground level. Must be located in remote area	Heat content must be >300 Btu/scf	Burner/pilot replacement every 3–5 years. Refractory replacement every 7–10 years	Requires liquid seals, double block valves, and flame arrestors	Stack temperature instrumentation and flow controls	Propane or natural gas pilot or auxiliary fuel supply. Forced air fan requires power
Open Flare								
Versatile and inexpensive. Some regions may not permit use of open flares. Applies to tank, truck, and marine vapor control	>98%	Produces NO_x, SO_2, CO, and sometimes smoke (hydrocarbon + particulates)	Smokeless burning for large turndown ratio will require air or steam addition. Must be located in remote area for dispersion of open flame	Heat content must be >300 Btu/scf	Burner/pilot replacement every 3–5 years. Refractory replacement every 7–10 years	Open flames may not be acceptable to the public. Requires liquid seals, double block valves, and flame arrestors	Minimal instrumentation. Cannot accommodate stack analyzers	Propane or natural gas pilot or auxiliary fuel supply. Steam- or air-assist requires power or steam supply
Thermal Incineration								
Applied to existing incinerators as fuel supplement or co-fired. Not typically cost-effective as a new application	>99%	Produces NO_x, SO_2, and CO. Less significant visible by-products	Limited applicability due to intermittent nature of loading or tank venting	May require constant vapor feed	Refractory replacement every 7–10 years. Requires long shutdown periods for maintenance	Generally requires enriching/inerting. Requires liquid seals, double block valves, and flame arrestors	Logic controller with complex temperature and flow controls and instrumentation	High-pressure fuel supply. Power for air blower or blowers
Catalytic Oxidation								
Not widely used for vapor control in petroleum industry. Good candidate as a tail gas polishing step	>98%	Produces SO_2 but very little NO_x, CO, and particulate Spent catalyst	Catalyst fouling due to impurities in vapor. Replacement is expensive	Must keep inlet hydrocarbon <1% by either diluting or pretreating to recover majority of hydrocarbon with another process	Catalyst must be washed every 2 years and replaced every 6–10 years	Requires diluting to remain below LEL. Requires liquid seals, double block valves, and flame arrestors	Temperature and flow controls	Propane or natural gas pilot or auxiliary fuel supply

Table 4—Flare System Cost Estimates[a] (Thousand U.S. Dollars, 1990)

Cost Type	Flare Type	
	Open Flare	Enclosed Flare
Equipment Capital Cost[b]	50–150	125–500
Processing Unit Installed Cost[c]	900–2,000	1,000–2,500
Annual Operating Costs[d]		
Rich Hydrocarbon Streams[e]	40–50	46–56[f]
Lean Hydrocarbon Streams[g]	90–100	96–106[f]

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[a] Based on a process sized for a maximum vapor rate of 936 standard cubic feet per minute (10,000 barrels per hour or 7,000 gallons per minute) and a maximum heat load of 100 million British thermal units per hour.

[b] Ranges supplied and verified by vendors. Represent differences in design for units of similar size.

[c] Ranges supplied and verified by vendors. Costs include grading, foundations, power and fuel supply, labor, rigging, freight, auxiliary equipment and instrumentation, and other installation costs. Does not include costs for necessary infrastructure, such as vapor arms, piping, and electrical. Some costs are compared in J. W. Young's "Vapor Control: Recovery and Destruction" [9] and *OAQPS Control Cost Manual* [11]. Ranges represent differences in location-specific resources and complexity of system. Costs can be greater if custom specifications from the purchaser are to be incorporated.

[d] Based on an average rate of 7.5 million standard cubic feet per day (1 million gallons per day) and 750 hours per year of actual operation. Costs include electrical (at $0.05 per kilowatt hour), operating and maintenance (at a labor rate of $20 per hour), and fuel (propane or natural gas at $3 per million British thermal units) for pilot and combustion firing. Ranges supplied by vendors and "Vapor Control: Recovery and Destruction," "Gasoline Marketing Industry (Stage I)—Background Information for Proposed Standards"[10], *OAQPS Control Cost Manual*, and J. Hill's "Controlling Emissions from Marine Loading Operations" [14]. Does not include capital recovery.

[e] Vapor streams of volatile products containing 40–60 percent hydrocarbon (for example, gasoline truck loading or tank vapors) capable of sustaining combustion [that is, higher heating value (HHV) > 300 British thermal units per standard cubic foot].

[f] Additional fuel required for preheat of flare chamber to 1400°F. Assumes 75 hours of preheat annually at 27.5 million British thermal units per hour.

[g] Assumes addition of 200-standard-cubic-foot-per-minute enrichment or fuel gas at a firing rate of 27.5 million British thermal units per hour for duration of vapor processing.

these types can be seen in Figures 8 and 9. Elevated open flares prevent potentially dangerous conditions at ground level by elevating the open flame (ignition source) and dispersing combustion products above working areas to reduce the effects of noise, heat, smoke, and objectionable odors. Elevated open flares are commonly used to treat process stream upsets. The elevated flame burns freely in open air. Mixing (complete combustion) can be improved at the flare tip by steam-assist, air-assist, or pressure-assist mechanisms.

The burners in an enclosed ground flare are contained within an insulated shell. The shell reduces noise, luminosity, and heat radiation and provides wind protection. Enclosed ground flares are used for continuous flow vent streams and provide more stable combustion conditions (temperature, residence time, and mixing). Temperatures are generally controlled via air dampers within the 1400 to 2000°F (760 to 1093°C) range.

Flares are comparatively inexpensive to install but can be costly for smaller applications [less than 500 cubic feet per minute (152 square meters per minute)]. Flares are the simplest to operate of the vapor control options considered and require less maintenance and recordkeeping than other options; however, there is no product recovery benefit, and flares require a supply of either natural gas or propane pilot fuel, which adds to operating costs. Although both types of flares offer greater than 98 percent destruction of VOC, other considerations (noise, luminosity, and public perception) may make flares less attractive for controlling vapors.

The flaring process can produce noise, heat radiation, light, sulfur oxides (SO_x), nitrogen oxides (NO_x), and carbon monoxide (CO) and can sometimes produce smoke. The generation of these by-products must be considered. Flares also represent an additional source of ignition, and this re-

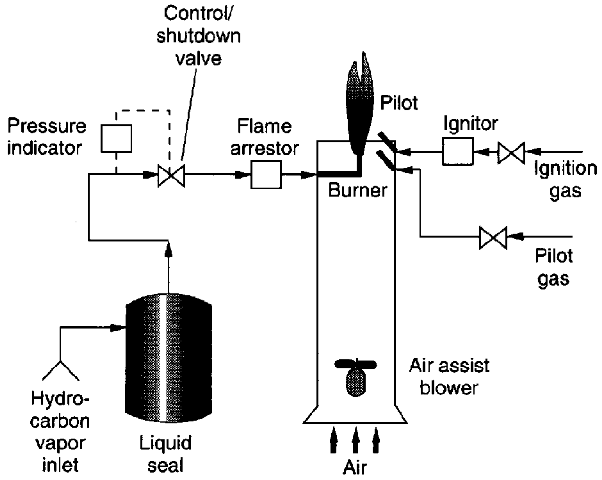

Figure 8—Typical Open Flare System

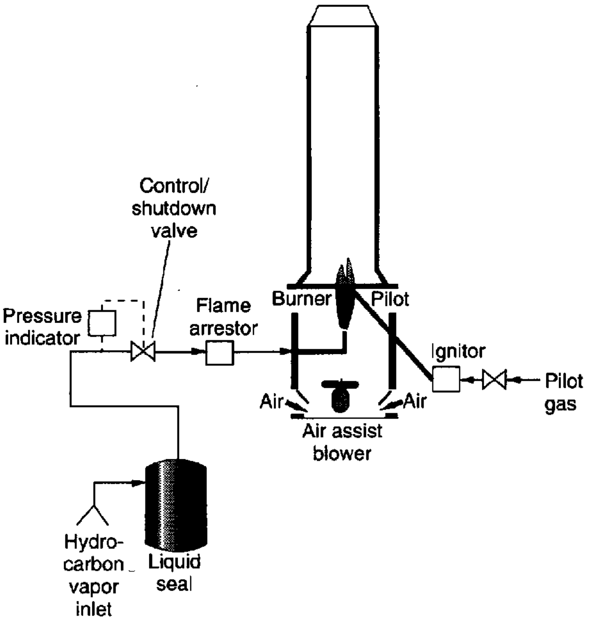

Figure 9—Typical Enclosed Flare System

quires additional safety precautions. Usually, a detonation arrestor, liquid seal, and shut-off valves separate the flare from the tank or vessel storing the petroleum product. Flares also generate radiant heat at base level and require at least 100 feet (30 meters) of open space around them for heat dissipation. Open flares can also pose a fire danger to structures in their vicinity. Consequently, the flares are generally located away from almost all other facility equipment and operations and can require long stretches of piping to their remote location.

The cost of a flare system to dispose of VOCs is dependent primarily on the flow rate of the material being flared and its heat content. These factors relate to the flare size and supplemental fuel requirements, respectively. The flare height is determined by the required distance to be maintained to prevent overheating of nearby process equipment and by codes or standards. The allowed gas velocity in the flare generally ranges from 60 to 400 feet per second (18 to 122 meters per second), and the vapor heat content must be at least 300 British thermal units per standard cubic foot (3,407 kilowatts per cubic meter) [15]. D. K. Stone's "Flares—Part I: Flaring Technologies for Controlling VOC-Containing Waste Streams" [16] contains scoping guidance on sizing of flares to control VOC emissions and estimating the cost of the flares.

5.2 Thermal Oxidation—Incineration

Another vapor control technology involving thermal oxidation is incineration. Incineration differs from flaring because no visible flame is present and the combustion process is more directly controlled and monitored.

An incinerator is an enclosed refractory-lined chamber that contains one or more burners. The chamber can be installed either horizontally or vertically. Combustion gases exit the chamber and are released through a vertical stack. A blower is sometimes used to supply air to the combustion chamber. The incoming waste hydrocarbon vapor can be co-fired with natural gas or propane to maintain consistently high oxidation temperatures.

An advantage of thermal incinerators is their destruction efficiency. If incinerator temperatures are maintained above 1800°F (982°C), greater than 99 percent hydrocarbon destruction is routinely achievable [17]. This efficiency is due to the constant high temperature, thorough mixing, and increased residence time in the combustion chamber. Some highly instrumented enclosed flares operate in virtually the same manner as incinerators.

Incinerators are typically used to process a constant feed of waste material, whereas flares are applied to combust gaseous waste from intermittent process upsets. Some incinerators are designed to provide additional process heat or steam through the use of heat exchangers or heat recovery units. This allows useful energy to be recovered from the hydrocarbon vapors. The hydrocarbon vapors therefore serve as a supplementary fuel. In some instances, displaced hydrocarbon vapors from tanks or loading operations at refineries can be vented to a fuel gas system and incinerated as supplementary fuel. Since thermal incinerators burn hydrocarbon vapors to meet part of the system fuel requirement, systems burning higher concentration emission streams can operate at lower cost.

The difficulty in applying incineration to hydrocarbon vapor streams from tank farm, truck rack, and marine operations is that vapors are not generated constantly by these operations. The nature of the operations yields periods of high gas volumes followed by periods of inactivity. This makes flaring a more popular option. Incinerators are also very costly to install because of required support equipment and utilities including high pressure fuel supplies (for example, natural gas) and substantial process control and monitoring equipment.

In addition, public perception of a new "incinerator" can make it difficult to locate and gain a permit for a new unit. Incineration can more easily be applied if the vapors collected from tanks or loading operations are to be diverted to an already existing incinerator and used to supplement the fuel supply.

Factors that affect the cost of thermal incineration systems include combustion air requirements, dilution air requirements, heat recovery, and incinerator design temperature. The amount of hydrocarbon in the emission stream will establish the combustion air requirement. If there is not enough oxygen in the emission stream to provide for complete combustion of the hydrocarbons, supplemental or dilution air will need to be supplied. Heat recovery allows recovery of some or most of the heat generated when the hydrocarbons are burned. The recovered heat can be used to preheat the emission stream or to fulfill other process requirements. Heat recovery requires an additional heat exchanger or additional heat exchangers in the system and will influence the capital cost of a system. Incinerator design temperature will affect the combustion efficiency and amount of supplemental fuel (if any) that must be provided to the system.

5.3 Catalytic Oxidation

Like flares and incinerators, catalytic oxidation units destroy hydrocarbon vapors via combustion, but the units destroy vapors via combustion at lower temperatures. Compared to approximately 1400°F (760°C) or greater for flares and incinerators, typical operating temperatures of catalytic incinerators range from 550 to 650°F (288 to 343°C). This makes catalytic incinerators very fuel efficient and reduces operating costs. Each catalytic oxidation unit typically consists of hot gas heat exchange, a thermal preheat zone with a standard burner, and a catalyst bed as shown in Figure 10. Downstream heat recovery is optional, as in thermal incinerators discussed in 5.2.

The incoming vapor stream is heated to the desired reaction temperature and exposed to a platinum-type, magnesium oxide-based or other metal-based catalyst that initiates and assists the oxidation reaction. The catalyst is supported on a distribution grid located in the midsection of the incinerator. The catalyst bed is generally a few inches deep, and its depth can be varied to provide optimum VOC removal efficiency at the desired combustion temperature. Catalyst beds can be either stationary or fluidized.

Precious metal catalysts are sensitive to contaminants in the feed streams and can be easily poisoned. Lead, zinc, mercury, and other heavy metals, as well as halogenated compounds and hydrogen sulfide, are potential poisons to catalysts. Also, heavy hydrocarbons (even in small amounts) will tend to deposit on fixed catalyst, which causes deactivation or masking. Research efforts are continuing to identify and develop catalysts that are resistant to specific poisons and masking agents. As the catalyst becomes less active, the efficiency of the unit cannot be restored by increasing combustion temperature; the catalyst has to be replaced. Catalyst replacement is relatively expensive. Fixed-bed catalysts usually must be purchased as modules tailored to the installation.

Catalytic incinerators are most effective at treating low-concentration vapor streams (less than 1 percent by volume). Treating higher concentration vapor streams can overheat and deactivate the catalyst. In many cases and certainly in vapor control systems for petroleum applications, dilution of the vapor stream would be required to lower the vapor concentration to 1 percent or below the LEL before treatment by catalytic oxidation. Because a large dilution volume would be required for the vapor stream of a volatile product (with a hydrocarbon concentration of 40–60 percent, as for gasoline), catalytic oxidation has not been applied often to control petroleum vapors from tank and loading operations. The dilution volume that would be required for volatile product streams such as gasoline is so large that catalytic incineration becomes impractical.

Catalytic oxidation is a better choice as a "polishing" step, following a recovery unit (for example, lean oil absorption) that removes the majority of the hydrocarbon. Given a constant flow of low-concentration vapor feed material, catalytic incinerators provide economical high-efficiency VOC destruction; typical destruction efficiency is 98 percent or higher.

Catalytic oxidation system costs are most affected by vapor stream flow rate, hydrocarbon concentration, and required destruction efficiency. The quantity of catalyst used in a catalytic oxidation system also depends on these three factors. The catalyst material in a catalytic oxidation system can account for as much as 50 percent of the system cost. Catalysts can range in cost from about $650 per cubic foot ($18.40 per cubic meter) for metal oxide catalysts to $3,200 per cubic foot ($90 per cubic meter) (1990 dollars) for precious metal catalysts [11].

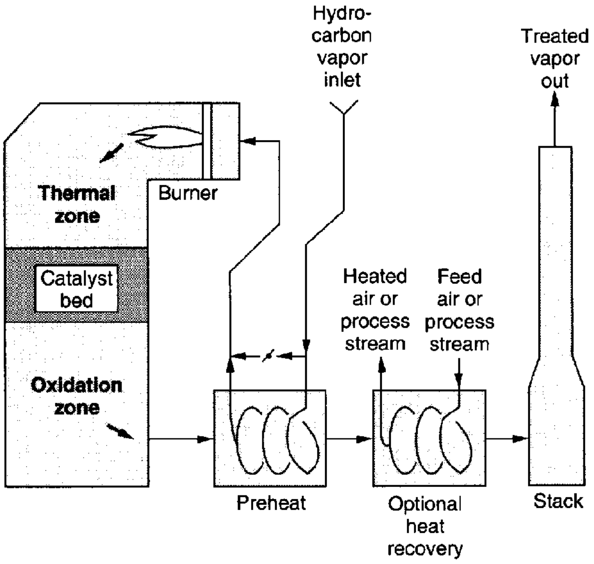

Figure 10—Typical Catalytic Oxidation System

SECTION 6—HYBRID PROCESSES AND EMERGING TECHNOLOGIES

Sometimes the conditions and requirements imposed on design of a vapor control system cannot be met by a single vapor control process. Some facilities have applied combinations of two or more of the control technologies described in this publication to achieve the level of control and operation desired. Adding another process may appear to make the control system more complicated and costly, but some of these systems complement each other and a combination of vapor control processes can sometimes be more economical than a single vapor control process.

Possible hybrid control processes include a vapor recovery process teamed with another vapor recovery process and a vapor recovery process teamed with a vapor destruction process. Examples of these possible combinations are described in this section. Emerging technologies described in this section are Brayton cycle, membrane separation, and refrigeration with cogeneration.

6.1 Absorption–Adsorption–Absorption

Absorption is frequently combined with carbon adsorption as a regeneration step. The addition of an absorption step before the carbon adsorption step creates a hybrid control configuration that combines the benefits of absorption and adsorption. A typical system arrangement is shown in Figure 11. Absorption is applied to lower the hydrocarbon concentration in the feed before carbon adsorption. Absorption involves contacting the inlet vapor with a lean flashed gasoline. This initial absorption step can also be used to condition the vapor and remove any reactive chemicals that might foul the carbon or cause temperature excursions. Activated carbon is then used to adsorb hydrocarbon from the vapor stream (see 4.1). The hydrocarbon vapors are stripped from the carbon during the regeneration step. The regenerated vapors are blended back into circulating gasoline in an absorption column and are returned to storage.

The primary advantage to using this hybrid control system is that the vapor is pretreated before the carbon adsorption step. The load on the carbon unit is significantly reduced because the first absorption step removes the majority of the hydrocarbon and any impurities that might deactivate the bed. This allows for less frequent bed regeneration and considerably reduces power consumption. Also, the carbon bed material does not require replacement as often. Vapor control efficiency is improved over lean oil absorption systems or carbon adsorption systems alone [18].

6.2 Vapor Recovery With Vapor Destruction

Vapor destruction devices are commonly used downstream of vapor recovery processes as a tail gas (vent gas) polishing step. This is done primarily to oxidize or combust hydrocarbons or other compounds that remain in the vented gas stream after the recovery process. The hybrid combina-

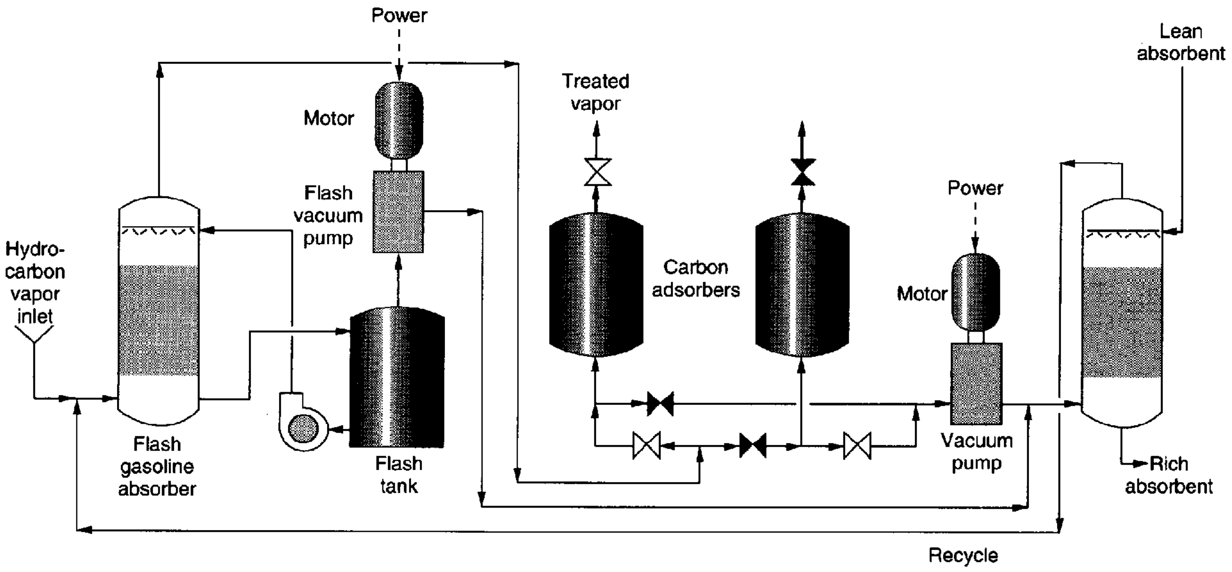

Figure 11—Typical Absorption-Adsorption-Absorption Recovery System

tion of recovery and destruction techniques allows for a system with the economic benefits of product recovery plus the operational flexibility and performance of vapor destruction processes. Any of the vapor destruction processes mentioned in Section 5 could be considered.

One reason for applying tail gas vapor destruction is to improve hydrocarbon-removal efficiency. Refrigeration units have difficulty providing greater than 90 percent hydrocarbon-removal efficiency unless they chill to very low temperatures; this, in turn, increases power consumption. Lean oil absorption units have difficulty providing high removal efficiencies when the inlet vapor hydrocarbon concentration drops below 10 percent. Both carbon adsorption units and refrigeration units have difficulty recovering propane and lighter hydrocarbon species. These recovery units may be designed to be more economical if followed by a vapor destruction device that achieves the high hydrocarbon-removal efficiency desired.

In addition to providing improved hydrocarbon-removal efficiencies, tail gas vapor destruction units combust or oxidize other impurities in the vapor stream. Vapors from crude and other petroleum intermediates may contain high levels of hydrogen sulfide that could cause odor or health problems if vented directly from vapor recovery units. Refrigeration units do not remove hydrogen sulfide, and lean oil units may not do a complete job of removal. Vapor destruction processes oxidize hydrogen sulfide to sulfur dioxide (SO_2).

6.3 Brayton Cycle

Recovery of gasoline vapors by direct condensation is a new process using reverse Brayton cycle technology. The reverse Brayton cycle is a highly effective refrigeration technology that has been used for years in air and gas liquefaction operations to produce cryogenic temperatures. This system has been successfully demonstrated in solvent recovery operations, and systems are being developed for small gasoline loading applications [maximum loading rate of less than 1,800 gallons per minute (less than 6,814 liters per minute)]. The design is only capable of handling an instantaneous flow rate of 250 standard cubic feet per minute (118 dry cubic meters per second), so this technique usually requires use of vapor balancing or a bladder tank to handle surges and lower the processing rate. Typical gas streams treated by Brayton cycle technology usually consist of 30 to 60 percent hydrocarbon vapors by volume [19].

The heart of the process is a turbo-expander/compressor unit, which is shown in Figure 12. When gasoline vapors are expanded and cooled, work done by the process is recovered by the compressor and used to pressurize the incoming vapor feed. Recovery of this work energy allows the process to run efficiently and operate with little additional energy. A series of separators are used to collect the cooled, condensed hydrocarbon product. Cooling water is used in the initial screw compression step and is first separated and later decanted from the condensed hydrocarbon. Water is also dried from the vapor stream using a molecular sieve. Many heat exchangers are employed to provide for efficient heating and cooling.

Advantages of reverse Brayton cycle technology units include their relatively small size as compared with other treatment (collection) technologies and low operating costs. Power consumption is estimated to be 75 horsepower (56 kilowatts) for a system capable of treating 250 standard cubic feet per minute (118 dry cubic meters per second) of gasoline vapors. However, capital costs are expected to be high. Many components for the units must be made of stainless steel, and some must withstand pressures as high as 150 pounds per square inch absolute (1,034 kilopascals). The degree of maintenance is expected to be high because conventional refrigeration systems can have a high degree of maintenance and because the technology is new.

6.4 Membrane Separation

Membrane separation of organic vapors is a low-pressure process for separating organic compounds from air. Membrane recovery technology has been developed over the past 6 years for recovering chlorinated solvents and chlorofluorocarbon vapors from air, and commercial systems are available for these applications. Adapting this technology to petroleum vapor recovery is a new advancement but has appeared promising at the pilot-scale. Petroleum-compatible membranes have been demonstrated to selectively recover propane, butane, and pentanes [20].

The physical separation is performed by passing the vapor stream through an array of semipermeable composite membrane modules, as shown in Figure 13. Organic compounds and air are preferentially drawn through the semipermeable membrane at a rate determined by their relative permeabilities and the vapor pressure difference formed on either side of the membrane. To induce transport, a vacuum maintains the vapor pressure on the permeate side of the membrane at a pressure lower than the vapor pressure of the feed vapor stream. A compressor can be used on the feed side to increase the pressure differential further. Membrane separation coupled with an initial compression/condensation step appears feasible for vapor recovery from loading operations and tank transfer. Typically, the permeate is 10–50 times more concentrated in hydrocarbons than the feed vapor stream. Concentrated hydrocarbon in the permeate is condensed and removed as a liquid. The purified air stream is removed as the retentate and vented to the atmosphere or further treated.

Modules can be connected in series and parallel flow arrangements to meet system design capacity and hydrocarbon-removal requirements. Hydrocarbon-removal efficiency of 90–99 percent can be achieved with a multistage system using several membrane modules.

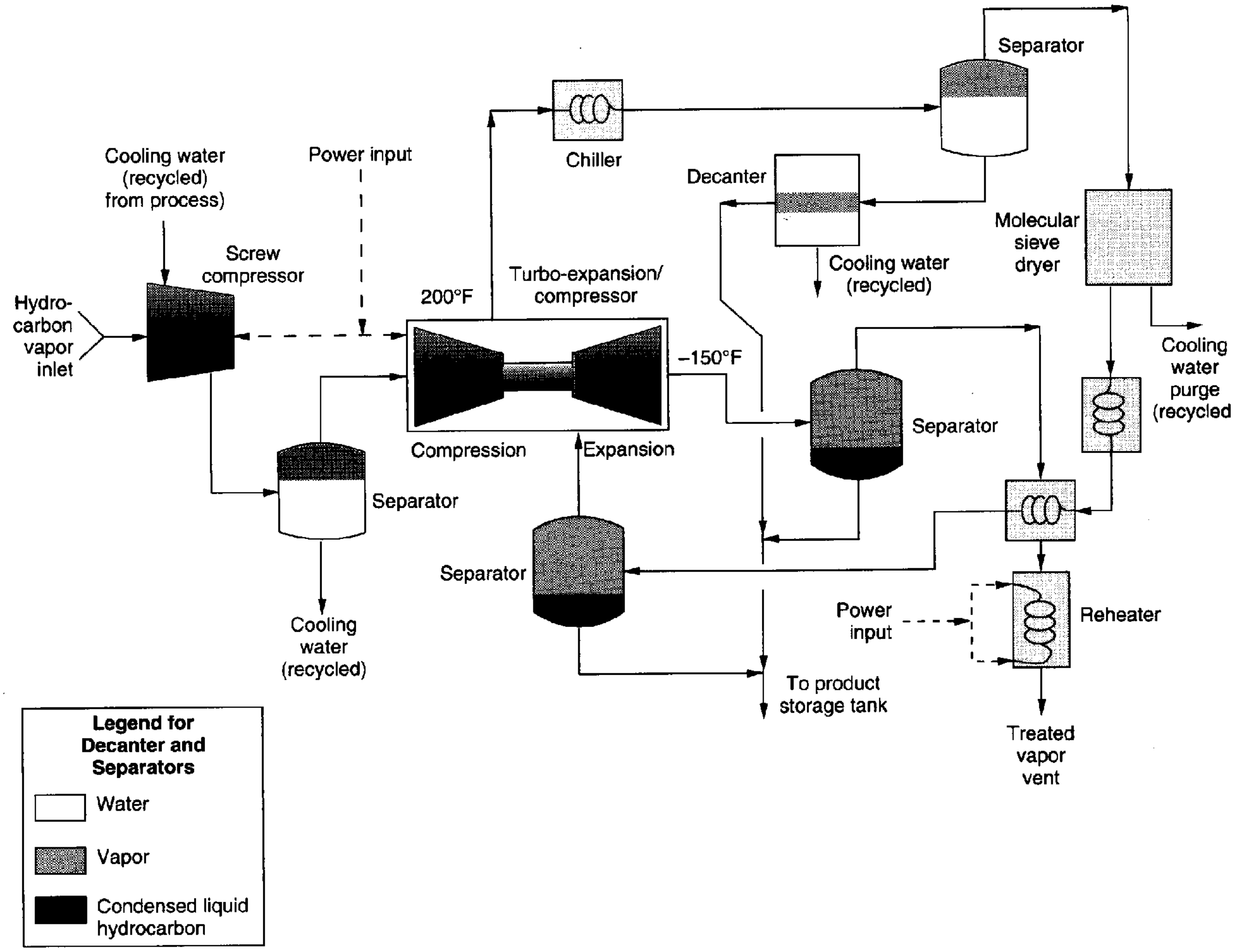

Figure 12—Typical Reverse Brayton Cycle Recovery System

Hydrocarbon vapor streams containing 0.05 to 20 percent by volume VOCs can be effectively treated through membrane separation. Feedstream temperatures of up to 140°F (60°C) can be tolerated, but high-temperature streams generally require precooling to preserve membrane integrity. So far, the membrane separation system has only been demonstrated at up to 140 standard cubic feet per minute (66 dry cubic meters per second), but a 400-standard-cubic-foot-per-minute (189-dry-cubic-meter-per-second) unit has been designed for application to gasoline loading vapor recovery [21].

Generally, costs associated with membrane separation technology are proportional to the volume of air treated and are largely unaffected by the hydrocarbon concentration of the vapor stream treated. Capital costs of systems range from $400 to $1,000 per standard cubic foot per minute ($189 to $472 per dry cubic meter per second) of capacity. Operating costs are relatively low because this system uses no fuel and requires electricity for only the compressor and the vacuum pump.

Safety concerns are relatively slight with membrane separation technologies because high temperatures and/or pressures are not encountered. Membrane modules have been designed from static spark-resistant materials to be safe with potentially flammable gas mixtures. Operation and maintenance requirements are less demanding than in other technologies because the system is relatively passive. Membrane systems are preferred in applications where compact size is desirable. Membrane treatment also generates no secondary waste disposal problems.

There has not yet been sufficient demonstration of membrane systems in vapor recovery service to determine the life of membrane materials. Replacement is anticipated after three years, but it is not known how actual conditions may affect membrane life. The tightly wound membrane modules could be susceptible to plugging and attack by impurities such as hydrogen sulfide. Should frequent replacement of membranes be required, operating costs associated with membrane replacement would be significant.

6.5 Refrigeration With Cogeneration

Refrigeration vapor recovery systems are sometimes more difficult to apply and more expensive to operate than some of the other control techniques that are available. This is particularly true as standards for VOC control efficiencies are tightened. Alone, refrigeration systems cannot always provide high hydrocarbon-removal efficiencies (much over 90 percent) unless the vapors are chilled to very low temperatures, which causes higher operating costs. Also, most refrigeration systems require a somewhat steady inlet flow rate for processing vapors. Coupling refrigeration systems with combustion in an engine/generator unit results in a vapor recovery system that is more equipped to provide high removal efficiencies and that recovers not only hydrocarbons but also energy. The basic system is shown in Figure 14.

For this system to function properly, it must be used in conjunction with either vapor balancing or a vapor bladder tank to reduce vapor flow surges and provide a steady flow rate to the system. The stored vapor is processed first by a standard refrigeration recovery unit. Actual recovery efficiency will vary depending on the inlet vapor composition but should be at least 85 percent for inlet concentrations of 50-percent hydrocarbon or greater. The vapor out of the refrigeration unit must be maintained at about 4- to 5-percent hydrocarbon so that enough fuel is provided for the engine. Resaturation of the outlet vapors would be necessary when the hydrocarbon concentration in the vapor is too low.

The saturated vapor stream is then combusted in a small internal combustion engine that drives a power generator. The attractive feature of this system is that under steady-state conditions, enough power is generated from the combustion process to run the refrigeration unit and little additional power is required. Of course, power requirements and power generation vary in actual application. A current design features a 75-horsepower (56-kilowatt) engine with a 58-kilowatt-per-hour generator. This system would support a gasoline vapor processing rate of 100,000 gallons per hour (378,500 liters per hour). At this processing rate, the refrigeration system is estimated to require 50 kilowatts per hour. It has demonstrated gasoline recovery of 1.2 gallons per 1,000 gallons (1.2 liters per 1000 liters) of gasoline loaded [22].

The refrigeration/cogeneration system is commercially available but has not been demonstrated on large-scale systems. This system would perform best for gasoline recovery or other high vapor pressure products where larger amounts of hydrocarbon could be recovered. It would be less efficient applied to petroleum products or crude with an RVP less than 5. It is most suitable for smaller truck loading and tank vapor processing applications because vapor balancing or vapor storage in bladder tanks is needed.

Capital cost of the system is comparatively high, and installation of the system might require an additional expense

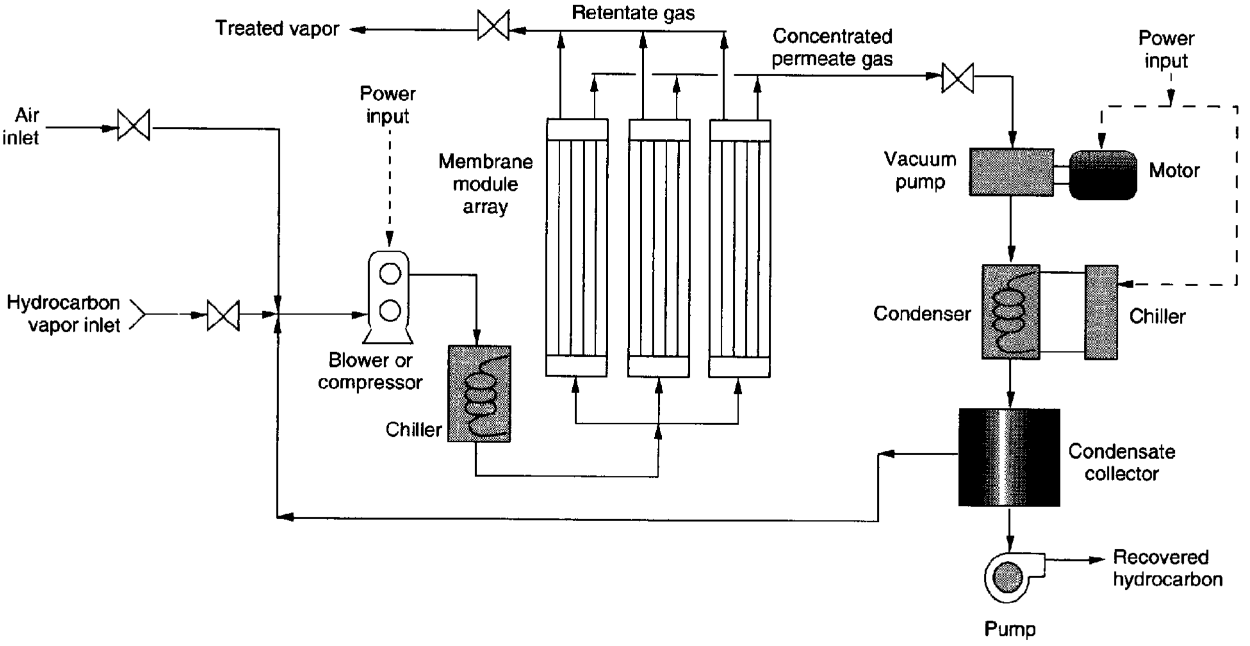

Figure 13—Typical Membrane Vapor Separation System

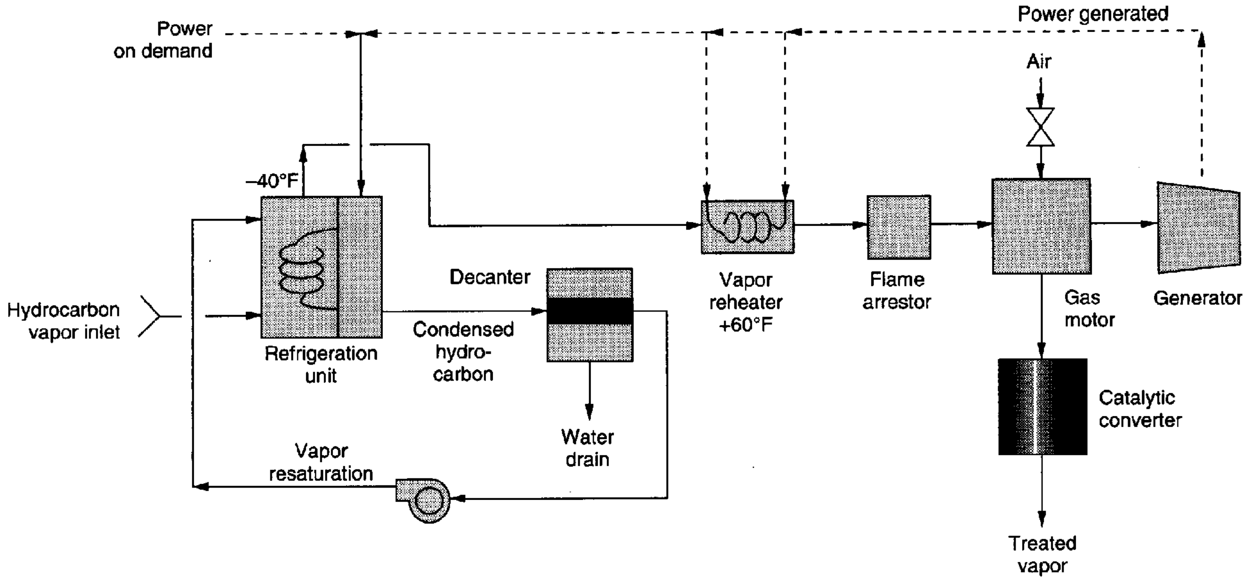

Figure 14—Typical Refrigeration/Cogeneration System

for utility tie-in or transformers. Additional flow control and other instrumentation must also be installed. However, operating cost will be very small. The system will generate some secondary waste products, including chiller condensate and internal combustion by-products, including CO, NO_x, and SO_2. These combustion by-products can be minimized through the use of a standard catalytic converter, as is used on automobile exhaust.

SECTION 7—CONSIDERATIONS FOR EVALUATING VAPOR CONTROL TECHNOLOGIES

The vapor control technology checklists provided in Appendix A are intended to provide additional guidance in determining what facility parameters are most important in researching a vapor control technology and asking appropriate questions of vendors about their equipment. Each checklist is designed for a general type of vapor control option: vapor recovery systems or vapor destruction systems. Part A guides the user in researching information about the vapor process stream and the tanks, loading racks, or marine loading system to which the vapor control will be applied. Part B prompts the user for information that should be obtained from either vendors or other vapor control system users regarding the vapor control technology that is being considered (for example, carbon adsorption or enclosed flare).

Once completed, the checklists are designed to facilitate initial discussions with vendors and provide a foundation for additional discussions. The checklists are not intended to supply all necessary data that would be required before the preparation of purchase specifications but should stimulate discussions on vendor-specified advantages and disadvantages, approximate costs, applicability to a given process stream, and other concerns.

7.1 Data for Vapor Recovery Systems

The most critical information that must be obtained when vapor recovery systems are being considered is the characteristics of the emission stream to be controlled. For vapor recovery systems, information on the flow rate and temperature is critical. Whether the emissions are continuous or occur intermittently will, in part, determine what types of recovery systems might be applicable. The composition of the emission stream will also affect system applicability. For example, large percentages of light hydrocarbons in the emission stream might preclude use of a refrigeration system.

7.2 Data for Vapor Destruction Systems

To select a vapor destruction system, the heat content of the emission stream must be known in addition to the flow rate, temperature, and pressure. Whether the emissions are continuous or intermittent will also affect the types of control devices that may be applied. Trace contaminants such as halogens or hydrogen sulfide in the emission stream will affect the applicability of some systems, such as catalytic oxidation systems.

SECTION 8—REFERENCES

8.1 Referenced Publications

1. API Publication 2517, *Evaporation Loss from External Floating-Roof Tanks*, 3rd edition, American Petroleum Institute, Washington, D.C., February 1989.
2. API Publication 2519, *Evaporation Loss from Internal Floating-Roof Tanks*, 3rd edition, American Petroleum Institute, Washington, D.C., June 1983.
3. *Manual of Petroleum Measurement Standards*, Chapter 19, "Evaporative Loss Measurement," Section 1, "Evaporative Loss from Fixed-Roof Tanks," (formerly API Publication 2518), 2nd edition, American Petroleum Institute, Washington, D.C., October 1991.
4. *Compilation of Air Pollutant Emissions Factors*, U.S. Environmental Protection Agency, Report No. AP-42, Volume I, 4th edition, Research Triangle Park, NC, September 1985.
5. API Publication 2514A, *Atmospheric Hydrocarbon Emissions from Marine Vessel Transfer Operations*, 2nd edition, American Petroleum Institute, Washington, D.C., September 1981.
6. "An Information Paper on Marine Vapor Recovery Systems," prepared by the Oil Companies International Marine Forum (OCIMF) task force, London, England, January 1990.
7. "Draft Text of Standards for Vapor Emission Control Systems," International Maritime Organization (IMO) Subcommittee on Bulk Chemicals, Report of the 21st Session, London, England, October 1991.
8. "Marine Vapor Control Systems: Final Rule," *Federal Register* 55(120)25396, June 21, 1990.
9. J.W. Young, "Vapor Control: Recovery and Destruction," presented at API Marine Technical/Environmental Conference, Chantilly, VA, January 1992.
10. "Gasoline Marketing Industry (Stage I)—Background Information for Proposed Standards," preliminary draft, U.S. Environmental Protection Agency, Washington, D.C., November 1991.
11. *OAQPS Control Cost Manual* (EPA-450/3-90-006), 4th edition, U.S. Environmental Protection Agency, Office of the Air Quality Planning and Standards, Research Triangle Park, NC, January 1990.
12. W. Vatavuk, "Pricing Equipment for Air Pollution Control," *Chemical Engineering*, May 1990, pp. 126–130.
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18. J.C. McGill, "Hydrocarbon Vapor Emission Control from Marine Loading Facilities," Hydrotech Engineering, Inc., Tulsa, OK, 1988.
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20. R.W. Baker et al., "Separation of Organic Vapors from Air," *Journal of Membrane Science*, Volume 31, 1987, pp. 259–271.
21. Vendor Information on Application of Membrane Separation Process to Gasoline Loading Operations, Membrane Technology and Research, Inc., Menlo Park, CA, 1990.
22. Edwards Engineering Corp., "Refrigeration for Marine Vapor Recovery," presented at API Marine Technical/Environmental Conference, Chantilly, VA, January 1992.

8.2 Suggested Further Reading

The following publications and reports are suggested materials for further information on vapor controls and evaporative emissions from petroleum industry sources.

API Recommended Practice 1004, *Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles*, 7th edition, American Petroleum Institute, Washington, D.C., November 1988.

Control of Hydrocarbon Emissions from Gasoline Loading by Refrigeration Systems (EPA-600/7-81-121), U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1981.

Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals (EPA-450/2-77-026), U.S. Environmental Protection Agency, Research Triangle Park, NC, October 1977.

Control of Volatile Organic from Bulk Gasoline Plants (EPA-450/2-77-035), U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1977.

Control Techniques for Volatile Organic Emissions from Stationary Sources (EPA-450/2-78-022), U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1978.

Demonstration of Vapor Control Technology for Gasoline Loading of Barges (EPA-600/2-84-140), U.S. Environmental Protection Agency, Research Triangle Park, NC, August 1984.

Destruction of Air Emissions Using Catalytic Oxidation (EPA-600/D-88-107), U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1988.

Guidelines for the Design and Operation of Gasoline Vapour Emission Controls, Institute of Petroleum, London, England, 1st edition, 1992.

APPENDIX A—VAPOR CONTROL TECHNOLOGY CHECKLISTS

Vapor Control Technology Checklist

Vapor Recovery Systems

Part A — Facility and Process Stream Information

Facility's Source of Hydrocarbon Vapor (for example, Tanks, Trucks, Marine Vessels):	Product Type(s):

Maximum Tank or Vessel Fill Rate: (gal/min) (bbl/hr)	Maximum Vapor Flow Rate: (scfm)	Average Vapor Flow Rate: (scf/day)
Storage Pressure (psia): (min) (max)	Storage Temperature (°F): (min) (max)	Duration of Filling or Loading: (hr)

Operation Schedule: (hr/day) (hr/yr)	Maximum Vapor Pressure of Product: Reid (psia) True (psia) @ °F
Utilities Available: Cost: electric: ($/kwh) compressed air (psig): ($/scf) steam (psig): ($/scf) other:	Vapor Stream Total Hydrocarbon (%): (max) (min) (avg)

Vapor Balanced?	Inerted?
Approximate Value of Recovered Product: ($ per gal)	
Other notes:	

Stream Composition (wt%)

Major Components	Product #1	Product #2
methane		
ethane		
propane		
butanes		
pentanes		
C_6+		
sulfur (as H_2S)		
other impurities		
water content		

Part B — Vapor Control System Information (To be supplied by vendors or equipment users)

Technology Considered:	Vendor Company Name:	Contact:
Hydrocarbon Reduction Efficiency:	Address:	Phone: ( ) Fax: ( )

Preliminary Quotation	Instrumentation Required:	Turndown Ratio:
Equipment Capital Cost (Range):	Power Requirements:	Noise Level:
Installed Cost (Range):	Required Safety Devices:	Waste Disposal:
Annual Operating Costs electrical: materials: steam: cooling water: other:	Other Auxiliaries:	Manpower – Routine Operation: (hrs/wk) Manpower – Maintenance: (hrs/wk)

Delivery Schedule: (wks)	Equipment Lifetime: (yrs)	Carbon, Lean Oil, or Refrigerant Charge: (lbs)	Regeneration Options:
Other Installations (references):			

Vapor Control Technology Checklist
Vapor Destruction Systems

Part A — Facility and Process Stream Information

Facility's Source of Hydrocarbon Vapor (for example, Tanks, Trucks, Marine Vessels):

Product Type(s):

Maximum Tank or Vessel Fill Rate: (gal/min) (bbl/hr)

Maximum Vapor Flow Rate: (scfm)

Average Vapor Flow Rate: (scf/day)

Storage Pressure (psia): (min) (max)

Storage Temperature (°F): (min) (max)

Duration of Filling or Loading: (hr)

Operation Schedule: (hr/day) (hr/yr)

Maximum Vapor Pressure of Product: Reid (psia) True (psia) @ °F

Utilities Available: Cost:
- electric: ($/kwh)
- compressed air (psig): ($/scf)
- steam (psig): ($/scf)
- other:

Vapor Stream Total Hydrocarbon (%): (max) (min) (avg)

Stream Composition (wt%)

Major Components	Product #1	Product #2
methane		
ethane		
propane		
butanes		
pentanes		
C_6+		
sulfur (as H_2S)		
other impurities		

Vapor Balanced?

Inerted?

Fuel Supply Available (nat. gas or propane?): (Btu/scf)

Vapor Heat Content: (Btu/scf)

Max Heat Rate: (Btu/hr)

Vapor Flammability Limits (% hydrocarbon): UEL: LEL:

Other notes:

Part B — Vapor Control System Information (To be supplied by vendors or equipment users)

Technology Considered:

Vendor Company Name:

Contact:

Hydrocarbon Reduction Efficiency:

Address:

Phone: ( )

Fax: ( )

Preliminary Quotation

Equipment Capital Cost (Range):

Installed Cost (Range):

Annual Operating Costs
- electrical:
- materials:
- pilot fuel:
- supplemental firing fuel:

Instrumentation Required:

Power Requirements:

Required Safety Devices:

Secondary Pollutants:
- NO_x: (lb/10^3gal)
- CO: (lb/10^3gal)
- Other ________: (lb/10^3gal)

Turndown Ratio:

Noise Level:

Waste Disposal:

Manpower – Routine Operation: (hrs/wk)

Manpower – Maintenance: (hrs/wk)

Delivery Schedule: (wks)

Equipment Lifetime: (yrs)

Combustion Blower Size: (hp)

Optimum Combustion Temperature: (°F)

Other Installations (references):

Amount of Catalyst (catalytic oxidation only): (lbs)

Order No. 852-25570

1-1102—3/93—5C (1E)

American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005