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Wednesday
June 6, 1984

**40 CFR
Part 61
National Emission Standards for
Hazardous Air Pollutants**

Part IV

**Environmental
Protection Agency**

40 CFR Part 61

**National Emission Standards for
Hazardous Air Pollutants; Proposed
Standards for Benzene Emissions From
Coke By-Product Recovery Plants;
Proposed Rule and Notice of Public
Hearing**

**ENVIRONMENTAL PROTECTION
AGENCY**
40 CFR Part 61
[AD-FRL-2538-3]
**National Emission Standards for
Hazardous Air Pollutants; Proposed
Standards for Benzene Emissions
From Coke By-Product Recovery
Plants**
AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule and Notice of Public Hearing.

SUMMARY: The proposed standard would limit benzene emissions from new and existing sources in coke by-product recovery plants. The proposed standard implements section 112 of the Clean Air Act and is based on the Administrator's determination of June 8, 1977 (42 FR 29332) that benzene is a hazardous air pollutant. The intent of the standard is to protect the public health with an ample margin of safety.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standard for coke by-product recovery plants.

DATES: Comments. Comments must be received on or before August 21, 1984.

Public Hearing. If anyone contacts EPA requesting to speak at a public hearing by June 27, 1984, a public hearing will be held on July 25, 1984, beginning at 10:00 a.m. Persons interested in attending the hearing should call Ms. Shelby Journigan at (919) 541-5578 to verify that a hearing will occur.

Requests to Speak at Hearing. Persons wishing to present oral testimony must contact EPA by June 27, 1984.

ADDRESSES: Comments. Comments should be submitted (in duplicate if possible) to: Central Docket Section (LE-131), Attention: Docket Number A-79-16, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460.

Public Hearing. If anyone contacts EPA requesting a public hearing, the public hearing will be held at the Office of Administration Auditorium, Research Triangle Park, N.C. Persons interested in attending the hearing should call Ms. Shelby Journigan at (919) 541-5578 to verify that a hearing will occur.

Persons wishing to present oral testimony should notify Ms. Shelby Journigan; Standards Development Branch (MD-13), U.S. Environmental

Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

Background Information Document. The background information document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Benzene Emissions from Coke By-Product Recovery Plants—Background Information for Proposed Standards" (EPA-450/3-83-016a).

Docket. Docket A-79-16, containing supporting information used in developing the proposed standards, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Dr. James U. Crowder, (919) 541-5601, concerning technical aspects of the industry and control technologies, and Mr. Gilbert H. Wood, (919) 541-5578, concerning regulatory decisions and the standard. The address for both parties is Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:
Introduction

Benzene was listed as a hazardous air pollutant under section 112 of the Clean Air Act on June 8, 1977 (42 FR 29332). Section 112 defines a "hazardous air pollutant" as one which, in the judgment of the Administrator, "causes or contributes to air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness." In EPA's judgment, benzene emissions from coke by-product recovery plants pose significant health risks to exposed populations and warrant Federal regulatory action under section 112.

Coke by-product recovery plants are currently largely uncontrolled, and use of the technology selected as the basis for the proposed standards would substantially reduce benzene emissions and associated health risks. The level of control selected as the basis for the proposed standards would result in fuel savings and increased produce recovery. As a result, the net nationwide annualized cost of the proposed standards would actually be a savings. [In general, even though the purchase of

air pollution control equipment may result in a net savings, affected sources do not necessarily purchase that equipment voluntarily because they may be able to attain a higher rate of return on their investment if given the opportunity to invest elsewhere.]

This preamble first summarizes the proposed standard for coke by-product recovery plants and the impacts of the standard. It then explains the rationale for each of the decisions made in selecting the proposed standard. These decisions include the selection of the source category, the selection of emission points, the selection of the level of the standard, the selection of the format of the standard, and the selection of the specific requirements themselves. Administrative considerations, including Executive Order 12291 and the Regulatory Flexibility Act, are discussed at the end of the preamble.

Summary of Proposed Standards

The proposed standard would reduce benzene emissions from several emission sources at each coke by-product recovery plant through a combination of emission standards, equipment, work practice, and operational requirements, depending on the source to be controlled. Both new and existing sources would be subject to the provisions of the proposed standard. Alternative standards are also proposed for several emission sources, as are procedures for permitting the use of alternative means of emission limitation under section 112(e)(3) of the Act.

An equipment standard is proposed for the control of emissions from each tar decanter, tar intercepting sump, flushing-liquor circulation tank, tar storage tank, tar dewatering tank, light oil condenser, light-oil decanter, wash-oil decanter, and wash-oil circulation tank. The proposed standard would require that each affected source be totally enclosed with emissions ducted to the gas collection system, gas distribution system, or other enclosed point in the by-product recovery process. Unless otherwise specified, pressure relief devices, vacuum relief devices, access hatches, and sampling ports would be the only openings allowed on each source. The proposed standard would require that each access hatch and sampling port be equipped with a gasket and a cover or lid that is kept in a closed position when not in actual use.

This proposed equipment standard could be achieved with the use of a gas blanketing system. A gas blanketing system is a closed system operated at positive pressure and is generally

composed of piping, connections, and flow-inducing devices (if necessary) that transport emissions from the enclosed source back to the coke-oven battery gas holder, the collecting main, or another point in the by-product recovery process. Depending on the source to be controlled, dirty or clean coke-oven gas, nitrogen, or natural gas can be used as the gas blanket.

To ensure that the control equipment for each source is being properly operated and maintained, the proposed standard would require a semiannual inspection of the connections and seals on each gas blanketing system for leaks, using EPA Reference Method 21 (40 CFR Part 60, Appendix A). An organic chemical concentration of more than 500 ppm by volume above a background concentration would indicate the presence of a leak. The proposed standard would also require a semiannual visual inspection of each source and the piping of the control system for visible defects such as gaps or tears. The proposed standard would require that a first attempt at repair of each leak or visible defect be made within 5 days of detection, with repair within 15 days. The owner or operator would be required to record the results of the inspections for each source, and include the results in a semiannual report.

Proper maintenance of the system will help ensure the proper operation of the system. To this end, the proposed regulation would require an annual maintenance inspection for abnormalities such as pluggages, sticking valves, and clogged or improperly operating condensate traps. A first attempt at repair must be made within 5 days, with any necessary repairs made within 15 days of the inspection. If a system blockage occurs, the proposed regulation would require the owner or operator to conduct an inspection and make any necessary repairs immediately upon detection. The proposed standard would require that information regarding the annual inspection or repairs made to correct a system blockage also be included in the semiannual report.

The proposed standard would require the use of a control device designed and operated to achieve a 90-percent benzene emission reduction for storage tanks containing light oil (including benzene-toluene-xylene mixtures), refined benzene, or excess ammonia-liquor. This proposed design standard can be achieved with the use of a wash-oil scrubber, a gas blanketing system, or any other control system that is

designed and operated to achieve at least a 90-percent emission reduction.

The proposed regulation also would require that each affected storage tank be totally enclosed and sealed with emissions vented to the wash-oil scrubber (or other control device or system providing an equivalent emission reduction). Pressure relief devices, vacuum relief devices, access hatches, and sampling ports would be the only openings allowed on each tank. Each access hatch and sampling port must be equipped with a gasket and a cover or lid that is kept in a closed position when not in actual use. The semiannual inspection and repair of leaks in the seals and ductwork, and the annual maintenance inspection and repair program (including recordkeeping and reporting requirements) proposed for gas blanketed sources also would apply to these tanks and the vents to the control device. Monitoring of parameters related to the operation of the control device (such as wash-oil pressure and flowrate, and exit gas temperature for the wash-oil scrubber) also are included to ensure the proper operation and maintenance of any control device used to achieve compliance.

An equipment standard is proposed for the control of benzene emissions from each light-oil sump. The proposed standard requires that the surface area of each light-oil sump be completely enclosed so as to provide a closed system for the containment of emissions. This standard can be achieved with the installation of a tightly fitting permanent or removable cover, coupled with the use of a gasket material applied to the rim of the sump cover. The proposed standard would allow the use of an access hatch and a vent in the sump cover. However, any access hatch must be equipped with a gasket and cover or lid, and any vent must be equipped with a water leg seal, pressure relief device, or vacuum relief device. The proposed standard would also require the semiannual inspection of the seals for leaks. An organic chemical concentration of over 500 ppm, as measured by Reference Method 21, would indicate the presence of a leak. A first attempt at repair of any leak or visible defect would be required within 5 days of detection, with repair within 15 days. The results of the inspection would be reported semiannually. The proposed standard would not allow venting of steam or gases from other points in the coke by-product process to the light-oil sump.

The proposed standard would allow no emissions from the processing of naphthalene separated from the water of

a direct-water final cooler. This emission limit could be achieved by a process modification involving the absorption of naphthalene in tar, wash oil, or an alternative medium (other than water). For example, a mixer-settler could be added to the direct-water final cooler, or the direct-water final cooler could be replaced by a tar-bottom or wash-oil final cooler system. If a mixer/settler were used to remove naphthalene from the final cooler aqueous effluent, the proposed standard would require that the mixer-settler be totally enclosed with emissions ducted to the gas collection system, gas distribution system or other enclosed point in the by-product recovery process. This requirement could be achieved by controlling emissions from the mixer settler with a gas blanketing system. Unless otherwise specified, pressure relief devices, vacuum relief devices, access hatches, and sampling ports would be the only openings allowed on the mixer settler. Again, the proposed standard would require that each access hatch and sampling port be equipped with a gasket and a cover or lid that is kept in a closed position when not in actual use.

The proposed standard would also apply to leaks (i.e., fugitive emissions) from new and existing pieces of equipment in benzene service, including pumps, valves, exhausters, pressure relief devices, sampling connections, and open-ended lines. Pumps, valves, pressure relief devices, sampling connections, and open-ended lines in benzene service are those components that contact or contain materials having a benzene concentration of at least 10 percent by weight. Exhausters that contact or contain materials having a benzene concentration of at least 1 percent benzene by weight are also in benzene service.

The proposed standard would require that all pumps in benzene service be monitored monthly for the detection of vapor leaks. A weekly visual inspection for liquid leaks would also be required. The proposed standard would require that any pump with an organic chemical concentration at or above 10,000 ppm, as measured by Reference Method 21, be repaired within 15 days after detection of a leak, except when repair would require a process unit shutdown. An initial attempt to repair such a leak would have to be made within 5 days after the leak was detected. "Repair" means that the measured concentration is below 10,000 ppm.

Quarterly monitoring for leaks from each exhauster in benzene service also would be required. If an organic

chemical concentration at or above 10,000 ppm were detected, as measured by Reference Method 21, the proposed standard would require a first attempt at repair within 5 days, with repair of the leak within 15 days from the date the leak was detected.

The proposed standard provides three types of alternatives to the leak detection and repair requirements for pumps and exhausters. An owner or operator may use "leakless" equipment such as magnetically coupled or diaphragm pumps to achieve a "no detectable emissions" limit (i.e., 500 ppm above a background concentration, as measured by Reference Method 21). However, an annual performance test using instrument monitoring would be required to verify the "no detectable emissions" status of each pump and exhauster. Or, pumps and exhausters can be equipped with enclosed seal areas vented to a control device designed and operated to achieve a 95-percent benzene control efficiency.

A third alternative would exempt pumps equipped with dual mechanical seals with a barrier fluid between the two seals and exhausters equipped with seals with a barrier fluid system from the leak detection and repair requirements, except for the weekly visual inspection for liquid leaks from pumps. However, emissions from the barrier fluid reservoir must be vented to a control device designed and operated to achieve a 95-percent benzene control efficiency, the barrier fluid must be purged and added to the process stream, or the pressure of the barrier fluid must be maintained at a level above the pressure in the pump or exhauster stuffing box. A pressure or level indicator to detect any failure of the seal system or the barrier fluid system would be required, with the indicator checked daily or equipped with an alarm to signal failure of the system.

Under the proposed standard, valves in benzene service would be subject to requirements similar to those for pumps in benzene service. All valves in benzene service would be monitored monthly for the detection of leaks. If an organic chemical concentration at or above 10,000 ppm is detected, as measured by Reference Method 21, the proposed standard would require that the valve be repaired within 15 days. Again, a first attempt to repair the valve so that the measured concentration is below 10,000 ppm would be required within 5 days after the leak was detected. However, those valves that are found not to be leaking for 2 successive months could be monitored at quarterly intervals until a leak is

detected, at which time monthly monitoring would again be required.

The proposed standard would also provide alternatives to the required leak detection and repair programs for valves in benzene service. First, the owner or operator could elect to meet a performance level where less than 2 percent of all valves could be found leaking. Second, the owner or operator could follow a skip-period leak detection and repair program also based on a performance level of 2 percent. And finally, an owner or operator may use "leakless" valves such as sealed-bellows valves, for which monitoring would not be required. The proposed standard require that these "leakless" valves achieve a "no detectable emission" limit (i.e., 500 ppm above a background concentration, as measured by Reference Method 21). A performance test would also be required on an annual basis to verify the "no detectable emissions" status of each valve.

The proposed standard would also specify a "no detectable emissions" limit (i.e., less than 500 ppm above a background concentration, as measured by Reference Method 21), for pressure relief devices in benzene service. This emission limit could be achieved by equipping pressure relief devices with a rupture disc. The proposed emission limit would not apply to discharges during overpressure releases; however, the proposed standard would require that emissions from each pressure relief device be returned to a state of "no detectable emissions" (500 ppm or less) within 5 days after a discharge. Alternatively, an owner or operator could elect to vent emissions through a closed system to a control device designed and operated to achieve a 95-percent benzene control efficiency or greater, such as a flare.

Closed-purge sampling would be required by the proposed standard. The standard would require that material purged from sampling connections be returned to the process or collected in a closed disposal system. In-situ sampling would be exempted from the closed purge sampling requirements. The proposed standard would also require open-ended lines to be sealed with a cap, blind flange, plug, or second valve. An operational standard for open-ended lines would also require that the cap or other device be removed or opened only when the open-ended line is placed into service.

The proposed standard would also apply to pressure relief devices in liquid service, flanges, and other connectors. The proposed standard would not

require a formal leak detection and repair program. However, instrument monitoring must be performed within 5 days if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method. If an instrument reading of 10,000 ppm is measured by Reference Method 21, the proposed standard would require a first attempt at repair within 5 days, with repair of the leak within 15 days from the date the leak was detected.

Compliance with the proposed standards would be assessed through plant inspection and the review of records and reports that would document implementation of the requirements. On a semiannual basis, the owner or operator would report the number of leaks detected and the number of leaks not repaired during the 6-month period. Also, if any add-on control devices were used, the owner or operator would report semiannually any occurrences when parameters monitored exceed or drop below the design specifications. The owner or operator would also submit a signed statement in each semiannual report, indicating whether provisions of the standard had been met for the 6-month period. Recordkeeping and reporting requirements for alternative standards are also included in the proposed regulation.

Under the proposed standard, compliance would be required within 90 days of the effective date for existing sources and at startup for a new source. A waiver of compliance for an existing source could be approved by the Administrator for no more than 2 years from the date of promulgation under 40 CFR Part 61. Emission testing would be required only for equipment subject to the no detectable emissions standards or the alternative performance standard for valves. However, the proposed standard would require the following information for each plant to be included in the source report required by § 61.10 of the General Provisions: (1) A description of the control equipment used to achieve compliance for each source; and (2) the date of installation of the control equipment for each source, as certified by the owner or operator.

Summary of Environmental, Health, Energy, and Economic Impacts

The estimated environmental, health, energy, and economic impacts of the proposed standard were based initially on a data base composed of 55 coke by-product recovery plants. Information received recently from the industry and the U.S. Department of Energy indicate that 13 of these plants have closed

permanently during the past 2 years. Consequently, the impacts have been revised to reflect these closures. This preamble presents the revised impacts based on 42 plants. The impacts and associated calculations in the BID will be revised following proposal of the recommended standards.

Implementation of the proposed standard would reduce nationwide benzene emissions from the 42 operating coke by-product recovery plants from their current level of about 24,100 Mg/yr to about 2,700 Mg/yr, an 89-percent reduction. Total uncontrolled nationwide emissions of benzene and other volatile organic compounds also would be reduced from their current estimated level of 160,000 Mg/yr to about 35,000 Mg/yr, a 78-percent reduction.

As a result of this benzene emission reduction, the proposed standard would reduce the estimated maximum lifetime risk for the most exposed population from about 6.4×10^{-3} at current controls to about 3.0×10^{-4} . The reduction also would decrease the estimated annual leukemia incidence from about 2.2 cases per year at current controls to about 0.19 case per year. Due to the assumptions that were made in calculating the maximum lifetime risk and leukemia incidence numbers, there is uncertainty associated with the risk and incidence numbers presented here and elsewhere in this preamble. Although EPA acknowledges this uncertainty, the Agency believes that these estimates represent plausible, if not conservative, approximations of the potential cancer risks. The major uncertainties and assumptions in the estimation of health risks as well as alternative methods of presenting risk information are further described in a following section entitled, "Quantitative Health Risk Assessment."

Implementation of the proposed standards is not expected to result in any unreasonably adverse water pollution, solid waste, noise, or energy impacts. Actually, a slight net reduction of the benzene contained in process wastewater could be expected with the use of the gas blanketing system. A nominal increase in electrical energy or steam requirements could occur if gas blanketing piping were heated to prevent vapors from condensing or freezing in vent lines. However, the cost of this energy requirement would be largely offset by the recovery of benzene contained in the coke oven gases, which otherwise would have been discharged to the atmosphere.

The control required by the proposed standard would result in fuel savings and increased product recovery. As a result, the net nationwide annualized

cost of the standard would actually be a savings. The national capital cost associated with the proposed standards is estimated at about \$23.8 million over baseline costs (1982 dollars). A savings in nationwide annualized costs would be achieved by the proposed standard as a result of light-oil recovery credits. [In general, even though the purchase of air pollution control equipment may result in a net savings, affected sources do not necessarily purchase that equipment voluntarily because they may be able to attain a higher rate of return if given the opportunity to invest elsewhere.] The price of foundry coke could increase by as much as \$0.21/Mg, an increase of less than 1 percent from the baseline price, while the price of furnace coke would increase by less than \$0.02/Mg (1982 dollars) as a result of the proposed standard. An economic analysis indicates that the industry trend is to pass through some increases in costs to consumers.

Background Information on Health Effects of Benzene

On June 8, 1977, the Administrator announced his decision to list benzene as a hazardous air pollutant under section 112 of the Clean Air Act (42 FR 29332). A public hearing was held on August 21, 1980, to discuss the listing. Supplementary background information regarding the listing may be obtained from the maleic anhydride Docket Number OAQPS 79-3, Part I, and from the EPA document, "Response to Public Comments on EPA's Listing of Benzene Under Section 112" (EPA-459/3-82-003).

Quantitative Health Risk Assessment

The listing of benzene as a hazardous air pollutant under section 112 requires that EPA publish emission standards which provide an "ample margin of safety" to protect the public health. However, neither the language nor the legislative history of section 112 reveals any specific Congressional intent as to how to apply the phrase "ample margin of safety" to protect the public health from pollutants like benzene.

In some cases, scientific evidence indicates that a given chemical is hazardous at high levels of exposure but has not effect below a certain level. However, for most carcinogenic chemicals, including benzene, thresholds below which there is no cancer risk have not been established. There is some reason to believe that such thresholds may not exist for many carcinogens. For such substances, EPA and other Federal agencies have taken the position that any level of exposure may pose some risk of adverse effects,

with the risk increasing as the exposure increases.

Since a specific environmental carcinogen is likely to be responsible for at most a small fraction of a community's overall cancer incidence and since the general population is exposed to a complex mix of potentially toxic agents, it is virtually impossible with current scientific techniques to directly link actual human cancers with ambient air exposure to chemicals such as benzene. Consequently, EPA relies on mathematical modeling techniques to estimate human health risks. These techniques—"quantitative risk assessment"—are used to assess the risk of adverse health effects from exposure to benzene in the ambient environment by mathematically extrapolating effects found at the higher occupational exposure levels to the lower concentration levels characteristic of human exposure in the vicinity of industrial sources of benzene.

EPA's approach to risk assessment for suspected carcinogens may be divided into several steps. The first is a qualitative evaluation of the evidence to determine whether a substance should be considered a human carcinogen for regulatory purposes. As described earlier, this was done in the case of benzene before the chemical was listed as a hazardous air pollutant in 1977. The next stage is quantitative: how large is the risk of cancer at various levels of exposure? The result of this examination is a dose-response relationship from which a "unit risk factor" is derived. The unit risk factor represents the cancer risk for an individual exposed to a unit concentration (e.g., $1 \mu\text{g}/\text{m}^3$) for a lifetime.

The third stage of the risk assessment is to estimate how many people are exposed to the substance, and at what levels. Exposure estimates are combined with the unit risk factor to obtain estimates of the risk posed by air emissions of the pollutant, in this case benzene.

The estimated carcinogenic risks posed by benzene emissions are characterized by two ways: As the predicted annual incidence of leukemia (expressed as cases per year), and as the lifetime risk of leukemia for individuals exposed to the highest predicted annual average ambient benzene concentrations (expressed as a probability). "Annual incidence" represents the aggregate risk for the population residing within a specified distance of emitting sources. "Maximum lifetime risk" represents the probability of contracting leukemia for those individuals assumed to be exposed for a

lifetime to the highest average benzene concentrations predicted to occur in the ambient air in the vicinity of emitting sources.

The health risk estimated for benzene source categories are comprised of three components noted above: the unit risk factor,* based on a dose-response function derived from epidemiological data; the exposed population, estimated from census data; and the benzene ambient concentrations, derived from dispersion modeling of emissions.

EPA has extrapolated the leukemia risks identified for occupationally exposed populations (generally healthy, white males) to the general population for whom susceptibility to a carcinogenic insult could differ. The presence of more or less susceptible subgroups within the general population would result in an occupationally-derived risk factor that may underestimate or overestimate actual risks. To the extent that there are more susceptible subgroups within the general population, the maximum individual lifetime risks may be underestimated.

On the other hand, general population exposures to benzene are much lower than those experienced by the exposed workers in the occupational studies, often by several orders of magnitude. In relating the occupational experience to the general population, EPA has applied a linear, non-threshold model that assumes that the leukemia response is linearly related to benzene dose, even at very low levels of exposure. There are biological data supporting this approach, particularly for carcinogens. However, there are also data which suggest that, for some toxic chemicals, dose/response curves are not linear, with response decreasing faster than dose at low levels of exposure. At such levels, the nonlinear models tend to produce smaller risk factors than the linear model. The data for benzene do not conclusively support either hypothesis. EPA has elected to use the linear model for benzene because this model is generally considered to be conservative compared to the non-linear alternatives. This choice may result in an overestimate of the actual leukemia risks.

EPA estimates ambient benzene concentrations in the vicinity of emitting sources through the use of atmospheric

*For benzene, the unit risk factor constitutes a point estimate of the human leukemia risk, expressed as the geometric mean of the risk factors derived from three epidemiological studies. Where animal data form the basis for the derivation of a risk factor, EPA may apply statistical tests (e.g., 95 percent confidence limits) to the resulting factor to obtain a "plausible upper bound" estimate of the unit risk

dispersion models. EPA believes that its ambient dispersion modeling provides a reasonable estimate of the maximum ambient levels of benzene to which the public could be exposed. The models accept emission estimates, plant parameters, and meteorology as inputs and predict ambient concentrations at specified locations, conditional upon certain assumptions. For example, emissions and plant parameters often must be estimated rather than measure, particularly in determining the magnitude of fugitive emissions and where there are large numbers of sources. This can lead to overestimates or underestimates of exposure. Similarly, meteorological data often are not available at the plant site but only from distant weather stations that may not be representative of the meteorology of the plant vicinity.

EPA's dispersion models normally assume that the terrain in the vicinity of the sources is flat. For sources located in complex terrain, this assumption would tend to underestimate the maximum annual concentration although estimates of aggregate population exposure would be less affected.

On the other hand, maximum individual lifetime risk estimates are based on two important exposure assumptions that may overestimate the risk for people living around a source emitting benzene. The first assumption is that the dose to the most exposed individual is equal to the predicted outdoor ambient concentration; the second assumption is that the exposed individual stays in the same place for 70 years and is continuously exposed. Implicit in the second assumption is the notion that the source emits at the same level for these 70 years.

We recognize that these assumptions are simplifications. People rarely live in the same place for 70 years; some move out and some move in. Nor do plants operate continuously for 70 years using the same equipment.

The estimation of risk for partial lifetime exposure can, as a first approximation, be assumed to be proportional to the fraction of a lifetime that a person has been exposed to pollution from the particular source. For example, the risk for 1 year can be approximated as 1/70 of the lifetime risk; the risk for 7 years of exposure might be 7/70 of the lifetime risk. Similarly, if the lifetime risk from a benzene source is 1 in 1,000, someone with a 7-year exposure would be able to roughly estimate his risk from a source as about 1 in 10,000.

It must be recognized, however, that this is an approximation, because the

risk for some pollutants may be higher or lower when people are exposed at different times in their lives, since the risk of developing certain cancers may be partly related to the age at which a person is exposed to a carcinogen. In addition, it is worth noting that this age sensitivity may be different for different chemicals. At this time, we have no information as to whether this is true for benzene.

The assumptions necessary to estimate benzene health risks and the underlying uncertainties have led some commenters on EPA's proposed rules to suggest that the risk estimates are inappropriate for use in regulatory decision making. Although EPA acknowledges the potential for error in such estimates, the Agency has concluded that both the unit risk factor for benzene and the evaluation of public exposure represent plausible, if conservative, estimates of actual conditions. Combining these quantities to produce estimates of the leukemia risks to exposed populations implies that the risk estimates obtained are also conservative in nature: that is, the actual leukemia risks from benzene exposure are not likely to be higher than those estimated. In this context, EPA believes that such estimates of the health hazard can and should play an important role in the regulation of hazardous pollutants.

EPA has received numerous public comments on most of the steps in the analytic process described above as a result of the announcement of the listing of benzene as a hazardous air pollutant and the intent to regulate a number of source categories. The full response to those comments is in the EPA document, "Response to Public Comments on EPA's Listing of Benzene Under Section 112" (EPA-450/5-82-003). EPA is presently inclined to continue to use the major features of the risk-assessment process described above, and in particular to adhere to the no-threshold assumption and the linear model.

Arguments have been advanced that, in addition to the conservative nature of the model used, the assumptions made by EPA (Carcinogen Assessment Group [CAG]) in the derivation of a unit leukemia risk factor for benzene represented "serious misinterpretation" of the underlying epidemiological evidence. Among the specific criticisms are: CAG (1) inappropriately included in its evaluation of the Infante et al. study two cases of leukemia from outside the cohort, inappropriately excluded a population of workers that had been exposed to benzene, and improperly assumed that exposure levels were comparable with prevailing

occupational standards; (2) accepted, in the Aksoy et al. studies, an unreasonable undercount of the background leukemia incidence in rural Turkey, made a false adjustment of age, and under-estimated the exposure duration; and (3) included the Ott et al. study in the analysis despite a lack of statistical significance.

EPA has reexamined and reevaluated each of the three studies. In summary, EPA concluded that one case of leukemia was inappropriately included from the Infante et al. study in computing the original unit risk factor. Additionally, EPA reaffirmed its decision to exclude dry-side workers from that study in developing the risk factor. The Agency agrees that the Aksoy et al. study was adjusted improperly for age; however, the exposures and durations of exposures are still considered reasonable estimates. The Ott et al. study was not eliminated from the risk assessment because the findings meet the test of statistical significance and because it provides the best documented exposure data available from the three epidemiological studies.

Based on these findings, the unit risk factor (the probability of an individual contracting leukemia after a lifetime of exposure to a benzene concentration of one part benzene per million parts air) was recalculated. The revised estimate resulted in a reduction of about 7 percent from the original estimate of the geometric mean, from a probability of leukemia of 0.024/ppm to a probability of leukemia of 0.022/ppm.

Selection of Coke By-Product Recovery Plants for Regulation

Nationwide benzene emissions from sources considered for regulation at coke by-product recovery plants are estimated at 24,100 Mg/yr. Dispersion modeling was used to estimate the benzene concentrations to which people within 20 kilometers of coke by-product plants are exposed as a result of the benzene emissions from these plants. Several million people (at least 15 to 20 million) live within 20 kilometers of the 42 existing by-product recovery plants. As a result of exposure to these benzene concentrations, the maximum lifetime risk of the most exposed population is estimated at 6.4×10^{-3} . The maximum lifetime risk is the estimated probability that the people who are exposed continuously for 70 years to the highest maximum annual average ambient benzene concentration estimated to result from benzene emissions from coke by-product recovery plants will contract leukemia as a result of exposure to these emissions. In addition, the leukemia

incidence is estimated at 2.2 cases per year within this population as a result of exposure to benzene emissions from these plants.

Although the maximum lifetime risk estimates apply to only a few people under particular conditions, EPA has calculated the lifetime risk for all individuals living within 20 kilometers of coke by-product recovery plants. The

following table (Table 1) presents EPA's estimate of the distribution of people at different predicted risk levels living around these sources. For each risk range in the first column, the second column indicates the number of people living within the 20 kilometer (12.5 miles) radius estimated to be exposed to benzene at levels that would produce those risks.

TABLE 1. POPULATIONS AT RISK

Risk (Probability) of Leukemia from Lifetime (70 years) Exposure	Number of People Exposed Within 20 km (12.5 miles) of Sources ^a
Greater than 1×10^{-2} (Greater than 1 in 100)	0
1×10^{-2} - 1×10^{-3} (1 in 100 to 1 in 1,000)	3,200
1×10^{-3} - 1×10^{-4} (1 in 1,000 to 1 in 10,000)	101,000
1×10^{-4} - 1×10^{-5} (1 in 10,000 to 1 in 100,000)	2,212,000
1×10^{-5} - 1×10^{-6} (1 in 100,000 to 1 in 1,000,000)	17,991,000
1×10^{-6} - 1×10^{-7} (1 in 1,000,000 to 1 in 10,000,000)	10,214,000
1×10^{-7} - 1×10^{-8} (1 in 10,000,000 to 1 in 100,000,000)	442,000

^aThe values for the number of people were calculated on a plant-by-plant basis and summed. Because some people are located within 20 km of more than one plant, the actual number of people exposed will be somewhat less than presented in this table.

Controls are available for reducing the benzene emissions at these plants (see section entitled, "Selection of Control Technologies"). The application of these controls also would reduce uncontrolled emissions of volatile organic compounds and potentially toxic pollutants other than benzene.

Based on the documented evidence that benzene is a leukemogen, the magnitude of benzene emissions from coke by-product recovery plants, the estimated ambient concentrations due to these emissions, the resulting estimated maximum individual risks and estimated incidence of leukemia in the exposed population, the potential reductions in these health risks achievable through available control techniques, and consideration of the uncertainties associated with these quantitative risk estimates, the Administrator finds that benzene emissions from coke by-product

recovery plants pose a significant risk of cancer and warrant Federal regulation under section 112.

Selection of Emission Points

Numerous benzene emission sources are present at each coke by-product plant. During 1979 and 1980, a survey of seven representative coke by-product plants was conducted to identify the sources that emit benzene and for which controls were potentially available. Visual observations were made and grab samples were obtained during the source sampling survey, which was followed by an emission testing program. Because of the numerous benzene emission sources throughout the plants, engineering judgment (coupled with site-specific production rates and process information provided by the plants), the results of sample analysis, and the results of emission

testing were used to estimate the emissions.

More than 20 emission sources were identified in the source sampling survey. The emission sources considered for regulation are listed in Table 2, as are the estimated uncontrolled industry-wide benzene emissions and the estimated uncontrolled benzene emissions from a medium-sized plant

producing 4,000 Mg of coke per day. Further information regarding the development of the emission factors used to estimate uncontrolled emissions is provided in Chapter 3 of the BID. Following is a brief description of typical coke by-product recovery processes and the associated emission points considered for regulation under the proposed standard.

process. The crude tar recovered during the tar separation process is then stored in heated storage tanks pending further use or sale.

Depending on the plant design, tar recovered during the separation process may also undergo refining to produce coal tar pitch. Like other tar products, pitch is stored in vented storage vessels. Benzene emissions from pitch storage tanks were not evident during emission testing because this pollutant is driven off with the lighter fractions. In addition, this process is practiced at few by-product plants. For these reasons, pitch storage tanks and pitch prilling operations (the refining of pitch to produce extruded pencils or beads) were not considered for regulation under the proposed standards.

The ammonia produced in a coke oven is approximately 0.2 percent of the weight of the coal fed to the ovens. Flushing liquor sprayed into the collecting mains absorbs some of the ammonia, and water condensed in the primary cooler absorbs an additional amount. Although aqueous ammonia solutions are decanted from the tar in a variety of processing vessels, the excess ammonia-liquor storage tank was the only benzene emission source identified in ammonia recovery or ammonia wastewater processing facilities.

Before light oils are recovered from the coke oven gas, the temperature of the gas is cooled from approximately 60° C to about 25° C by a final cooler. As the gas is cooled, some of the water and most of the naphthalene in the gas are condensed into the cooling medium. Both water and naphthalene are removed from the gas to prevent problems downstream. The three types of final coolers currently used by the industry are: (1) Direct-water, (2) tar-bottom, and (3) wash-oil final coolers.

Available data indicate that 19 plants use a direct-water final cooler. When a direct-water final cooler is used. The condensed naphthalene in the final cooler must be periodically removed from the hot well of the final cooler to prevent clogging of tubes, vents, or meters. Benzene emissions result when crude naphthalene is removed from the hot well of the direct-water final cooler and transported in open troughs, refined by melting or steam drying, or stored while it is hot for convenience in handling. After separation of the naphthalene, the water is cooled in an inducted-draft cooling tower and recirculated to the final cooler. The water contains benzene, which is released to the atmosphere when the water is cooled against air in an open

TABLE 2. UNCONTROLLED BENZENE EMISSIONS FROM COKE BY-PRODUCT RECOVERY PLANT EMISSION SOURCES

Emission source	Uncontrolled industry-wide emissions (Mg/yr)	Emissions from a medium-sized plant (Mg/yr) ^a
Tar decanter	3,560	108
Tar-intercepting sump	4,380	133
Flushing-liquor circulation tank	417	13
Tar dewatering tanks	874	29
Tar storage tanks	556	17
Excess-ammonia liquor storage tanks	417	13
Direct-water final cooler cooling tower	5,500	390 ^b
Naphthalene separation and processing	2,180	156 ^b
Tar-bottom final cooler cooling tower	696	100 ^b
Wash-oil decanter	143	5.5
Wash-oil circulation tank	143	5.5
Light-oil condenser and light-oil decanter vent	3,200	125
Light-oil sump	632	22
Benzene storage tanks	71	8.5 ^c
Benzene-mixture (BTX) storage tanks	23	8.5
Light-oil storage tanks	276	9
Pumps	463	16 ^d
Valves	312	11 ^d
Pressure relief devices	209	7 ^d
Exhausters	25	4 ^d
Sampling connections	41	1.4 ^d
Open-ended lines	14	0.3 ^d

^aUncontrolled benzene emissions, a medium-sized plant producing 4,000 Mg of coke per day.

^bAn actual plant would have either a direct-water final cooler or a tar-bottom final cooler. Naphthalene processing would be found only at a plant with a direct-water final cooler.

^cThis emission source would only occur at a plant which practices benzene refining.

^dUncontrolled emissions estimate for a plant that does not practice benzene refining.

In the coke by-product recovery process, the various components of the gases emitted from the coke oven battery are separated and recovered to obtain products such as crude tar, naphthalene, light oils, benzene-mixtures, and refined benzene. In the crude tar separation operation, the initial condensation of the tar contained in the coke oven gases occurs by direct contact with flushing liquor in the collecting and suction mains. Approximately 80 percent of the tar is separated from the gas in the mains and is flushed to a tar decanter (also known as a flushing liquor decanter). The

remaining light tar and condensate (approximately 20 percent) is forwarded to the tar-intercepting sump for the separation or light oils and wastewater. The flushing liquor that separates from the tar in the tar decanter is then transferred to the flushing-liquor circulation tank, which cools the flushing liquor and recirculates it to the gas mains. In many plants, the coal tar is not refined on site but is sold to tar refiners. A common requirement is that the tar contain no more than 2 percent water. For this reason the water content of the tar may be further reduced by a tar-dewatering (dehydration)

cooling tower. At plants using a direct-water final cooler, the final-cooler cooling tower is usually the largest source of benzene emissions.

An estimated 12 plants use a tar-bottom final cooler. In this system, the cooling medium (water) is passed through a pool of tar in the bottom of the final cooler. Naphthalene in the water dissolves in the tar and the tar is recirculated to tar storage tanks, sold as a final product, or refined. As in a direct-water final cooler, the final cooler water is cooled in a cooling tower and recirculated to the final cooler. Although use of a tar-bottom final cooler eliminates naphthalene processing and the resultant benzene emissions, the tar may become saturated with benzene. Thus, benzene may still be contained in the final cooler water and released when the water is cooled against air in the final-cooler cooling tower.

A wash-oil final cooler uses petroleum wash oil as the cooling medium rather than water or tar. Naphthalene dissolves in the wash oil, which is indirectly cooled with heat exchangers and recirculated to the final cooler. This system is used by four plants. Benzene emissions from naphthalene processing and from the final-cooler cooling tower are virtually eliminated with the use of a wash-oil final cooler system. However, benzene from the wash oil may still be emitted from the wash-oil decanter and the wash-oil circulation tank associated with the wash-oil final-cooler system. Wash-oil decanters and wash-oil circulation tanks may also occur in the light-oil recovery operation.

Light oil is a clear, yellow-brown oil composed primarily of benzene, toluene, xylene, solvent naphtha, and numerous minor constituents that boil between 0°C and 200°C. Light oil is recovered from the coke oven gas in a scrubber in which wash oil absorbs the light oil from the gas. The benzolized wash oil (wash-oil and light-oil mixture) leaving the scrubber is separated by steam stripping, and the wash oil is cooled and recycled to the scrubber. The stripped vapors may be partially condensed in a light-oil condenser, while those that remain noncondensable may be forwarded to a light-oil decanter (rectifier) that separates the recovered light oil into intermediate and secondary fractions. The overhead, consisting of benzene, toluene, and xylene (BTX) is then forwarded to a water-cooled condenser.

Benzene emission sources in the light-oil recovery operation include wash-oil decanters, wash-oil circulation tanks, light-oil condensers, light-oil decanters (or common vents for light-oil condensers and light-oil decanters),

storage tanks containing light oil (including BTX) or refined benzene, and light-oil sumps. The wastewater forwarded to the light-oil sump (from which light oil may be recovered by distillation) may also emit benzene, which is entrained or dissolved in the water.

Sources of benzene fugitive emissions at coke by-product recovery plants also include leaking pumps, valves, exhausters pressure relief devices, sampling connections, flanges, and open-ended lines. In the by-product recovery process, benzene is present in numerous process streams and final products. The streams are usually moved throughout the process unit by pumps through pipes, with the volume of flow regulated by valves. Exhausters, generally located in the tar separation sector of the plant, serve to move the coke oven gas in the collecting main. Benzene emissions from these sources at coke by-product recovery plants are specifically exempted from proposed EPA benzene fugitive emission standards (46 FR 1165, January 5, 1981).

Selection of Control Technologies

Many options are available for the control of benzene emissions from coke by-product recovery plants. Implementation of any of the control options would also reduce volatile organic compound (VOC) emissions. Control techniques that are effective in reducing or eliminating emissions include source enclosure used in conjunction with a gas blanketing system, source enclosure alone, wash-oil scrubbers, process modifications, leak detection and repair programs, and equipment for certain fugitive emission sources. Further information regarding these and other control techniques is provided in Chapter 4 of the BID.

Gas blanketing. Gas blanketing has been demonstrated at by-product recovery plants as an effective control technique for reducing VOC emissions, such as benzene, from process vessels and product storage tanks. This control technique can be applied to tar decanters, flushing-liquor circulation tanks, tar-intercepting sumps, tar dewatering tanks, light-oil condensers, light-oil decanters (or the common vent for a light-oil condenser and a light-oil decanter), wash-oil decanters, wash-oil circulation tanks, and storage tanks holding tar, excess-ammonia liquor, light oil, benzene mixtures, and refined benzene.

The basic principles of gas blanketing require sealing all the openings on a vessel or tank, supplying a constant pressure gas blanket with coke-oven gas, nitrogen or natural gas, and

providing for the recovery or destruction of displaced vapor emissions. Depending on the source to be controlled, displaced vapors from the enclosed source can be transported through a piping system to the collecting main, to the gas holder, or to another point in the by-product recovery process where the benzene will be recovered or destroyed. With source enclosure, the control efficiency of the blanketing system approaches 100 percent. However, deterioration of piping or sealing materials can occasionally result in leaks, thus reducing the overall control efficiency to as low as 93 percent.

With gas blanketing from the collecting main, a vapor recovery system is in place in the form of the by-product recovery process, which removes organics from the raw coke oven gas. One advantage of gas blanketing from the collecting main is the recovery of benzene and other organic material. At a medium-sized by-product plant producing 4,000 Mg of coke per day, benzene losses are estimated as high as 4 percent of the total benzene generated in the process. Depending upon the design of the system and the source to be controlled, much of this estimated process loss can be recovered by venting emissions to the collecting main.

For gas blanketing from the collecting main to work safely and effectively, each emission source must be enclosed to accept a slight, positive pressure without leaks to the atmosphere. For most vessels associated with crude tar production, enclosure would require closing atmospheric vent lines and connecting the tank's vent line to the gas blanketing line. However, tar decanters may require further modifications before a gas blanket can be applied. Tar decanter tops usually have a rectangular surface where the liquid is either exposed to the atmosphere or partially covered with concrete slabs set on steel support beams. At many plants, the decanter top must be removed, a water seal and metal cover installed, and gasket material added to provide a tight seal for the metal cover. A water seal suspended from the decanter roof near the sludge discharge chute would allow the major portion of the liquid surface to be blanketed at a small positive pressure, while allowing the remaining portion of the liquid surface (estimated at about 13 percent) to be opened to the atmosphere so as to provide clearance for a sludge conveyor. Because a portion of the liquid surface must remain open to the atmosphere, the benzene control efficiency of gas blanketing for

this source is lower than for other sources, but is estimated to be at least 95 percent.

Potential condensation of naphthalene or other tar components in the piping system and freezing of water vapor in the coke oven gas can be reduced or eliminated by steam tracing the affected line, controlling the temperature with electrical heating tape, or by a combination of both methods. Drip points can also be installed so that any condensate can be drained from the blanketing line. Three-way lubricated plug valves can also be provided to avoid sticking due to tar deposits and to isolate individual vessels during gauging or sampling operations. Although this equipment may not be necessary for each plant and would not be specifically required for any gas blanketing system, equipment costs for these items are included in the estimated system costs described in Chapter 8 of the BID because this equipment is considered a useful and reasonable part of gas blanketing systems.

Gas blanketing from the collecting main has been successfully demonstrated at one by-product plant for the control of emissions from two tar decanters and a flushing liquor circulation tank. At this plant, the gas blanketing line was connected to the offtake main upstream of the Askania regulatory (butterfly control valve). The blanketing pressure was typically controlled at 6 mm of water with a range of 4 to 8 mm of water. The decanter roofs were enclosed up to the sludge conveyor with steel plate and sealed with gasket material. Access hatches on both sources were covered and sealed; a vertical manifold of small valves was also installed to allow the operator to determine the level of tar and flushing liquor in the decanters. Three-way valves, atmospheric vents, and steam-out connectors for line cleaning were also installed. All lines were steam traced and insulated. No safety problems were reported by plant personnel operating the positive pressure portion of the system at this plant.

Engineering analyses indicate that no technical, safety, or operating problem would preclude the use of gas blanketing from the collecting main for the control of tar-intercepting sumps, tar storage tanks (including dewatering tanks), and excess ammonia-liquor storage tanks. These sources are generally in proximity and, like the tar decanter and flushing-liquor circulation tank, are all associated with the crude tar and ammonia liquor recovery operations practiced in the initial steps

of the by-product recovery process. The proximity of the sources allows the use of a common large header to supply coke oven gas from the collecting main; smaller diameter piping can then connect the individual vent lines to the header. Because the liquid contents of these tanks result from water contact with the raw coke oven gas, coupled with the subsequent separation of tar and flushing liquor, no contamination problems are expected from a raw coke oven gas blanket. In addition, these sources can accept the low positive pressure (6 to 10 mm water) of the coke oven gas from the collecting main without danger of rupture.

With gas blanketing from the gas holder, a vapor destruction system is in place because the clean oven gas is burned to underfire the coke ovens and to recover the fuel value. One advantage of blanketing with clean coke oven gas from the gas holder is the elimination of oxidation reactions between oxygen in the air and organic materials in the vessels. These reactions often result in a sludge that may pose fouling and plugging problems in lines and process equipment. In addition, oxygen infiltration can cause tank vapors to reach the explosive limits of vapor when tanks are periodically emptied or when significant cooling takes place. Applying a positive pressure blanket would eliminate oxygen infiltration and maintain the vapor space in the tank above its upper explosive limit.

Gas blanketing with clean coke oven gas has been demonstrated for the control of emissions from sources associated with light-oil recovery, including the light-oil condenser, light-oil decanter, light-oil storage tank, wash-oil decanter, and wash-oil circulation tank. Again, the proximity of these sources allows the use of a common large header to supply coke oven gas from the gas holder; smaller branches of piping can then connect the individual vent lines to the header. For most vessels in the light-oil plant, source enclosure would require closing all vents to the atmosphere and connecting the tank's vent line to the gas blanketing line. Horizontal tanks in the light-oil plant may require some minor modifications to withstand a pressure of 36 to 46 cm (14 to 18 in) of water. As previously discussed, heat tracing and insulation can be used to avoid condensation, accumulation, and plugging in the lines. Steam-out connections can also be used for line cleaning, and three-way lubricated plug valves can be provided so that an individual line or vessel can be isolated for maintenance or sampling.

Gas blanketing with clean coke oven gas from the gas holder has been demonstrated for these sources at three by-product plants. At one plant, undesulfurized coke oven gas from the gas holder is used to control wash-oil decanters and wash-oil circulation tanks. At this plant, a header line is connected to the coke oven gas line exiting the wash-oil scrubbers. The tanks are connected with a line that runs from the header pipe. Isolating valves and steam-out connections are provided. However, none of the lines are heated or insulated. Although no pressure relief valves or controllers are used, water u-seals are placed in the lines to remove condensate and to protect the system from excessive pressure.

At a second plant, desulfurized gas from the battery underfire system is used to blanket the wash-oil decanters, wash-oil circulation tanks, light-oil decanters, and light-oil condensers. In a separate plant at the same location, an undesulfurized gas blanket is applied to light-oil decanters and wash-oil circulation tanks. All lines are steam traced and insulated.

At a third plant, undesulfurized coke oven gas from the gas holder was used to blanket the wash-oil decanter and circulation tank, two light-oil storage tanks, three light-oil condensers, and two light-oil decanters. Each emission source was equipped with three-way valves, flame arrestors, steam-out connections, steam tracing, and insulation. No major modifications or repairs were required to pressurize the emission sources.

Plant personnel have reported no safety problems with gas blanketing systems for emission sources in light-oil recovery operations. In addition, only routine operating problems, such as sticking valves, have been experienced. These difficulties can be avoided with good operation and maintenance practices.

It is the EPA conclusion that no safety or operating problems would preclude the application of gas blanketing to benzene storage tanks. For this source, however, coke oven gas is not recommended as the blanketing medium because of the possibility of contamination from components in the coke oven gas. However, nitrogen or natural gas can be used as a substitute. Emissions could be routed to the coke oven gas main and burned in the gas combustion system, or emissions may be routed to the gas main before light-oil removal and recovered in the wash-oil scrubbing operation. As with other sources, the benzene storage tanks must

be enclosed to accept a positive pressure gas blanket without leakage. In addition, heat-traced and insulated lines would be needed for winter operations due to the freezing temperature of benzene (42° F).

Wash-oil scrubbers. A wash-oil scrubber can be used to absorb benzene and other organics from vented emissions. Engineering analysis shows that application of a properly designed and operated wash-oil scrubber can attain a control efficiency for benzene of 90 percent. Although wash-oil scrubbers are less effective than gas blanketing, they were considered by the EPA because, in some cases, they could be less costly.

Wash-oil scrubber technology is already used in the coke by-product recovery industry to recover the light oil from the coke oven process gas stream. Light oil is a mixture composed primarily of benzene (60 to 85 percent) that also has toluene (6 to 17 percent), xylene (1 to 7 percent), solvent naphtha (0.5 to 3 percent), and other minor constituents. The coke oven enters the scrubber from the bottom where it is contacted by wash oil flowing from the top of the scrubber, countercurrent to the gas flow. The wash oil is a petroleum straw oil with a boiling point over 200° C (392° F), has a high absorptive capacity for light oil, and does not react with the gas. After passing through the scrubber, the benzolized wash oil (wash-oil and light-oil mixture) is steam stripped in a wash-oil still to separate the light oil from the wash oil. The debenzolized wash oil is then cooled and recirculated back to the wash-oil scrubber. The absorption of the light oil by the wash oil is highly dependent on temperature; the absorption decreases as temperature increases. For this reason, the coke oven gas is cooled from about 60° C (140° F) to about 15–30° C (59–86° F) before it enters the scrubber. The temperature of the wash oil as it enters the scrubber is about 17.32° C (63–90° F); it is generally a few degrees hotter than the gas to prevent water condensation and emulsification problems. The wash-oil scrubber recovers about 90 percent of the light oil from the coke oven gas.

A wash-oil scrubber used to remove benzene from vented emissions would be of similar design, but scaled-down from the wash-oil scrubber used in the light-oil recovery process. Emission sources vented to the wash-oil scrubber must be enclosed so that vapors displaced from the sources due to working and breathing losses could not go anywhere except to the scrubber. The scrubber design analyzed by the EPA has no fan continuously venting the

vapors to the scrubber. In the scrubber analyzed by the EPA, emissions would enter the bottom of an unpacked scrubbing chamber and contact a spray of wash oil from the top of the scrubbing chamber. The wash oil would be a slipstream taken from the wash-oil used in light oil recovery. The scrubber operating temperatures (e.g., the temperature of the gas leaving the scrubber) would be about 30° C (86° F), which is similar to the temperatures in the scrubber used in the light oil recovery process. The benzolized wash oil would be routed to the light-oil recovery plant, where the benzene would be recovered in the wash-oil still and the debenzolized wash oil would be cooled before being recirculated to the wash-oil scrubber. The engineering analysis shows that the scrubber can achieve 90 percent control efficiency for benzene. More details on specific design parameters are described later in this section.

A wash-oil scrubber was used as a control device at one plant (that is no longer operating) in the coke industry. As discussed below the design and operation of this scrubber differed significantly from a wash-oil scrubber that would achieve 90 percent control of benzene emissions. The scrubber was a portion of a large organic emission control project which principally consisted of installation of by-product recovery and control devices instead of flaring the coke oven gas. The wash-oil scrubber was applied to emissions vented from a tar storage tank, a tar dewatering tank, an excess ammonia-liquor storage tank, and an ammonia-liquor sump. Access manways on the storage tanks were covered and sealed. The sump was enclosed with a metal cover and gasket. Vent lines from each enclosed vessel carried emissions to a single scrubber. A slipstream of the wash oil used in the light-oil recovery process was diverted to the wash-oil scrubber. The benzolized wash oil from the scrubber was then routed to the wash-oil still in the light-oil recovery unit, where it was debenzolized and recirculated back to the wash-oil scrubber. As noted above, the wash-oil scrubber was part of a larger project to control total organic emissions rather than benzene emissions alone. The plant operator stated that the scrubber had never been tested and no records were available of estimates of the control efficiency. In addition, the plant is no longer operating. Therefore, no test data or company estimates of the design control efficiency are available. However, the EPA has concluded that this particular wash-oil scrubber system

would not control benzene emissions. The main reason is that the temperatures of both the wash oil and the gas were significantly hotter than the temperatures (about 30° C (86° F)) characteristic of the gas and wash oil in EPA's scrubber design that achieves 90 percent control and in the scrubbers in the light oil recovery units. The wash-oil spray in the scrubber at this plant was a slipstream from the wash oil leaving the stripper, before it was cooled. Therefore, its temperature was 110° C (230° F), which is higher than the boiling point of benzene (69° C or 176° F). In addition, during the tar dewatering process, in which the tar is steam-heated to drive off water, the gas entering the scrubber without precooling would probably be around 100° C (212° F). At these temperatures for the wash oil and gas, the absorption of benzene by the wash oil would be negligible. Therefore, the EPA did not consider the design of the wash-oil scrubber at this particular plant for application as a benzene control device. This application demonstrates the enclosure and venting of sources to a wash-oil scrubber, and the compatibility of the wash-oil scrubber with the light-oil recovery system. However, to control benzene emissions, the wash oil and the gas would have to be cooled.

Wash-oil scrubbers were considered for controlling emissions from storage tanks containing light-oil, BTX, benzene, or excess ammonia-liquor. The pressure drop through the scrubber is negligible; therefore, the tanks would not be subjected to pressures significantly higher than normal operating conditions. Consequently, little modification of the tanks, other than covering and sealing any openings, would be necessary. Also, the wash-oil circulation, distillation, and cooling capacity needed to operate a scrubber applied to these sources is expected to be within the capacity of most existing light-oil recovery plants. Estimated costs for applying a wash-oil scrubber to storage tanks containing light-oil, BTX, benzene, or excess ammonia-liquor are less than the estimated costs of gas blanketing these sources. More details of the cost estimates can be found in the section of this preamble entitled "Selection of the Basis of the Proposed Standard" and in Chapter 8 of the BID.

Wash-oil scrubbers were also considered for controlling emissions from tar storage and dewatering tanks. As noted above, the emissions from these sources are at elevated temperatures. For the scrubber to achieve an emission reduction efficiency near 90 percent, the vapors would have

to be cooled, either by a condenser or by a sufficiently high flow rate of cool wash-oil spray. In addition, several other factors would have to be addressed to design a wash-oil scrubber to control benzene emissions from tar storage and dewatering tanks. These include the effects of a hot gas saturated with water, lack of equilibrium data for the mixture of organics expected to be in the emission stream, fouling of equipment from heavy organics from the tar, emulsification problems, and wastewater treatment problems. Even if it is assumed that these factors are not problems with the design, the estimated cost of using the wash-oil scrubber, including cooling the emissions, is higher than the estimated cost of gas-blanketing these sources. (Details of the cost estimates can be found in Chapter 8 of the BID.) Also, as discussed above, the emission reduction achieved by the wash-oil scrubber is less than by gas blanketing. For these reasons, the use of wash-oil scrubber for tar storage and dewatering tanks was not considered further.

The application of the wash-oil scrubber to process vessels other than storage tanks in the tar and light-oil recovery plants was also considered. These sources generally have higher benzene emission rates than the storage tanks. To control these sources, a higher volume of wash-oil spray would be needed. The wash-oil circulation, distillation, and cooling systems required to handle the wash oil would likely be beyond the capacity of most existing light-oil plants. In addition, other sources in the tar recovery plant would need to have the same design considerations described above for tar storage and dewatering tanks. Increasing the capacity of the wash-oil circulation, distillation, and cooling systems, and cooling the emissions before scrubbing them would make the wash-oil scrubber more expensive than gas blanketing, which is the more efficient control system. Therefore, use of the wash-oil scrubber was not considered further for sources other than storage tanks containing light oil, BTX, benzene, or excess ammonia-liquor. The Agency invites comments on its assessment of the application and costs of the wash-oil scrubber to control emissions at coke by-products plants.

Engineering design calculations indicate that a wash-oil scrubber with an inner diameter of 20.3 cm (8 in), an active height of 4 m (13 ft), and a wash-oil (solvent) feed rate of 0.03 l/s (0.5 gal/min) will achieve a continuous benzene control efficiency of at least 90 percent from light oil, BTX, benzene, and excess

ammonia-liquor storage tanks. This design is based upon the following worst-case assumptions: (1) Maximum gas feed rate to the scrubber of 19 e/s (40.1 ft³/min) resulting from a maximum anticipated liquid displacement rate of 19 e/s (300 gal/min) as tank is filled, (2) a maximum gas phase benzene concentration of 17 percent by volume (corresponding to storage of pure benzene liquid at 32° C), and (3) maximum scrubber operating temperature (i.e., temperature of the gas leaving the scrubber) of 32° C (90° F). Two other design parameters, which do not fall in the category of "worst case," are the following: (1) The spray nozzle that distributes wash oil within the column produces a mean droplet diameter of 1 mm, and (2) the smallest droplet produced by the same nozzle has a diameter of 0.2 mm.

For sources with gas phase benzene concentrations of less than 17 percent and for smaller gas phase (vent system) flow rates, smaller scrubbers with correspondingly lower wash-oil feed rates can be designed. However, a scrubber of the design summarized above will ensure that 90 percent efficiency is achieved at design (worst-case) conditions and that the benzene concentration in the absorber offgas stream can be maintained at or below the design level.

Light-oil sump cover. A tightly fitting cover can be used to reduce evaporative losses caused by wind blowing across the surface of a light-oil sump and mixing with benzene or other hydrocarbon vapors. A gasket material applied to the rim of the sump cover would provide a seal to prevent leakage and would also allow removal of the cover to permit access for sludge removal. A vertical vent could also be installed in the sump cover so excess pressure would not build up in the sump. Potential emissions from small pressure increases could be contained with the use of a water leg seal, a pressure relief device, or a vacuum relief device. Enclosing the sump would reduce evaporative emissions, but would still allow working losses (from increasing the liquid level in the sump) and breathing losses (from increasing the temperature of the liquid in the sump). For sumps operated at or near a constant liquid level, a 98-percent control efficiency is estimated for a tightly fitting sealed cover equipped with a vertical vent as compared to the uncontrolled situation with wind blowing across the exposed liquid surface.

Naphthalene Processing and Final Coolers. A process modification is an

effective control technique for benzene emissions from naphthalene processing and direct-water final-cooler cooling towers. At a plant operating a direct-water final cooler, a process modification would consist of replacing the direct-water final cooler with a tar-bottom final cooler, converting the direct-water final cooler to a tar-bottom final cooler by adding a mixer-settler, or replacing the direct-water final cooler with a wash-oil final cooler. A control efficiency of 74 percent is estimated for direct-water final-cooler cooling tower emissions through the installation of the tar-bottom process or a tar mixer-settler; collection of the naphthalene by means of a tar or wash-oil system would also eliminate emissions from naphthalene processing for an emission reduction of 100 percent. At a plant operating a tar-bottom final cooler, the process modification would be the replacement of the tar-bottom final cooler with a wash-oil final cooler. This control option would provide an industry-wide emission reduction of 100 percent from tar-bottom final-cooler cooling towers and naphthalene processing emissions.

Pumps. Fugitive emissions from pumps primarily result from leakage of process fluids around the pump drive shaft and through deteriorated seal packing or worn mechanical seal faces. These emissions can be reduced with the elimination of the seal by replacing the pump with a sealless pump or by using an improved seal (e.g., double mechanical seals). Because of process condition limitations, sealless pumps are not suitable for all pump applications. However, dual mechanical seal systems with a barrier fluid between the seals (and meeting certain other criteria) can achieve a benzene control efficiency of about 100 percent.

Another control option is the application of a leak detection and repair program based on monitoring each pump at monthly or quarterly intervals. Once detected, leaks from pumps usually can be repaired immediately because critically located pumps are spared at most by-product plants. Based on the leak detection and repair (LDAR) model (described in the EPA document, "Fugitive Emission Sources of Organic Compounds—Additional Information on Emissions, Emission Reductions, and Costs" [EPA-450/3-82-010]), monthly monitoring of pumps would achieve an industry-wide benzene control efficiency of about 83 percent, while quarterly monitoring would achieve an industry-wide control efficiency of about 71 percent.

Valves. Fugitive emissions from valves result when valve packings or O-

rings that are used to limit leakage of process fluids around valve stems deteriorate. Most valve leaks can be repaired while the equipment is in service by tightening the packing gland. Plug valves may be repaired by the addition of grease. Some valves cannot be repaired while in service. These valves include block valves, whose removal for repair or replacement might require a process shutdown. Other valves, such as control valves with a manual bypass loop, can be isolated for repair or removal.

The control options considered for valves in benzene service include the implementation of a leak detection and repair program based on monthly or quarterly monitoring intervals. Monthly monitoring would achieve an industry-wide benzene control efficiency of about 72 percent, as compared to the 63-percent industry-wide control efficiency achievable with quarterly inspections. A third control option considered is equipping valves with leakless equipment such as sealed bellows valves. The control efficiency of this option is approximately 100 percent.

Exhausters. Emissions from exhausters also occur at the seal. Control options for exhausters include the installation of seal systems with the barrier fluid degassing reservoir vented to a control device, or purging the barrier fluid and adding the fluid to a process stream, or maintaining the pressure in the barrier fluid above that of the stuffing box. The control efficiency for each of these methods is estimated at 100 percent. A second control option for exhausters is the implementation of a leak detection and repair program, based on quarterly or monthly monitoring intervals. Monthly monitoring would achieve a control efficiency of about 64 percent, as compared to the 55-percent control efficiency associated with quarterly inspections.

Pressure relief devices. Pressure relief devices may emit benzene fugitive emissions because of the failure of valve seating surfaces, improper reseating after relieving, or process operations near the relief valve set point. Fugitive emissions from pressure relief valves can be controlled by installing a rupture disc system upstream of these valves to prevent fugitive emissions from the valve seat. The control efficiency of the rupture disc system is approximately 100 percent. Emissions from pressure relief devices can also be controlled by venting emissions in a closed system to a control device, such as a flare. The control efficiency of this equipment option is at least 95 percent. However, use of a control device would also

reduce emissions resulting from a pressure release in addition to the fugitive emissions. The reduction of these emissions would increase the overall control efficiency of this option to a level approaching that of the rupture disc system.

Implementation of a leak detection and repair program, based on monitoring at monthly or quarterly intervals, was also considered as a control option for pressure relief devices. Monthly and quarterly monitoring would achieve an industry-wide benzene control efficiency of 53 percent and 44 percent, respectively.

Open-ended lines. Fugitive emissions from open-ended lines can be controlled by installing a cap, plug, blind, or second valve on the open end of the line. Capping of open-ended lines and closed-loop sampling represent readily available technologies that have been applied in the industry and exhibit control efficiencies of approximately 100 percent. However, the actual control efficiencies may depend on site-specific factors.

Sampling connections. When process samples are taken for analysis, obtaining a representative sample requires purging some process fluid through the sample connection. This sample purge could be vented to the atmosphere if the fluid is gaseous, and liquid sample purges could be drained onto the ground or into open collection systems where evaporative emissions would result. Fugitive emissions from sampling connections can be reduced by using a closed-purge sampling system that eliminates purging of process material and provides a benzene control efficiency of about 100 percent.

Selection of Basis of Proposed Standard

EPA selected a level for the benzene standard for coke by-product recovery plants through a two-step process. The first step in determining the basis of the proposed standard was the selection of the best available technology (BAT) as the minimum level of control. Best available technology for new and existing sources is technology which, in the judgment of the Administrator, is the most advanced level of control considering the economic, energy, and environmental impacts and any technological problems associated with the retrofitting of existing sources.

After selecting BAT, EPA identified a level of control more stringent than BAT and evaluated the incremental reductions in health risks obtainable against the incremental costs and economic impacts estimated to result from the application of the more stringent control level. This provides a

comparison of the costs and economic impacts of control with the benefits of further risk reduction. The benefits of risk reduction are expressed in terms of the estimated annual leukemia incidence and the estimated risk to the most exposed population. The results of this comparison determine whether, in the judgment of the Administrator, the residual risks remaining after application of BAT are unreasonable. If the risk remaining after application of BAT is determined to be unreasonable, further controls would be required.

This approach while recognizing that risk-free levels of exposure to carcinogens such as benzene may not exist, also considers the technological and economic factors that affect the pursuit of a "risk-free" or zero emissions goal and the uncertainties inherent in the estimation of carcinogenic risks. [For more detail, see the EPA document, "Response to Public Comments on EPA's Listing of Benzene Under Section 112" (EPA-450/5-82-003).]

In selecting BAT, EPA first considered the cost of control for each emission source by examining the annual cost of each benzene emission control option for each source and the resultant emission reduction. The emission sources considered for regulation are indicated on Table 2. EPA then examined the nonair environmental, energy, and economic impacts for the collection of the control options tentatively selected, based on a consideration of cost per megagram of emission reduction for each source to determine if the collection represents BAT for the industry as a whole. If these impacts were reasonable, the control techniques were selected as BAT and then were used in estimating the risks remaining after application of BAT.

The emission reductions and the average and incremental costs per megagram of benzene emission reduction are presented on Table 3. Costs per megagram of emission reduction (average and incremental) were calculated in terms of total emissions (benzene and other volatile organic compounds [VOC's]), as well as benzene alone. Control of benzene emissions also result in VOC control at no additional cost. Therefore, VOC control is an added benefit of benzene control. In regulatory decision-making regarding the acceptability of the cost for emission reductions achieved by a control technique, it is appropriate to consider the VOC as well as the benzene emission reductions. However, VOC emission reductions were considered only in the sense that VOC emission reductions can add weight to selecting a control technique as BAT.

TABLE 3. NATIONWIDE EMISSION REDUCTIONS AND COSTS OF CONTROL

Emission source	Control option ^a	Benzene				Total emissions (benzene and other VOC)			
		Uncontrolled emissions (Mg/yr)	Emission reduction (Mg/yr)	Average cost effectiveness (\$/Mg) ^b	Incremental cost effectiveness (\$/Mg) ^c	Uncontrolled emissions (Mg/yr)	Emission reduction (Mg/yr)	Average cost effectiveness (\$/Mg) ^b	Incremental cost effectiveness (\$/Mg) ^c
1. Final-cooler cooling tower ^d	1. Tar-bottom final cooler ^e	8,370	6,240	(310)	(310)	100,600	67,300	(29)	(29)
	2. Wash-oil final cooler	8,370	8,370	4,200	18,000	100,600	100,600	350	1,100
2. Tar decanter tar-intercepting sump, and flushing liquor circulation tank	Gas blanketing	8,340	8,020	(310)	(310)	17,890	17,200	(140)	(140)
3. Tar storage tanks and tar-dewatering tanks	Gas blanketing	1,430	1,410	640	640	33,400	32,900	27	27
4. Light-oil condenser, light-oil decanter, wash-oil decanter, and wash-oil circulation tanks	Gas blanketing	3,490	3,420	120	120	4,940	4,890	85	85
5. Excess ammonia-liquor storage tank	1. Wash-oil scrubber	417	376	1,030	1,000	597	535	710	710
	2. Gas blanketing	417	409	1,200	2,900	597	585	810	1,300
6. Light-oil storage tanks and benzene-mixture storage tanks	1. Wash-oil scrubber	299	269	1,800	1,600	424	385	1,200	1,200
	2. Coke oven gas blanketing	299	293	2,100	6,100	424	418	1,500	4,500
7. Benzene storage tanks	1. Wash-oil scrubber	71	63	1,100	1,100	71	63	1,100	1,100
	2. Nitrogen or natural gas blanketing	71	69	1,700	8,100	71	69	1,700	8,100
8. Light-oil sump	Sealed cover	632	619	(230)	(230)	909	893	(160)	(160)
9. Pumps	1. Quarterly inspections	463	328	100	100	669	473	72	72
	2. Monthly inspections	463	335	110	120	669	557	73	84
	3. Dual mechanical seals	463	463	2,800	16,000	669	669	1,900	11,000
10. Valves	1. Quarterly inspections	312	196	(230)	(230)	450	203	(160)	(160)
	2. Monthly inspections	312	226	(110)	670	450	327	(76)	460
	3. Sealed bellows valves	312	312	17,000	61,000	450	450	12,000	42,000
11. Exhausters	1. Quarterly inspections	25	14	1,300	1,300	107	59	290	290
	2. Monthly inspections	25	16	2,600	9,900	107	69	590	2,400
	3. Degassing reservoir vents	25	25	24,000	62,000	107	107	5,700	15,000
12. Pressure-relief devices	1. Quarterly inspections	209	93	(400)	(400)	302	135	(280)	(280)
	2. Monthly inspections	209	110	(300)	270	302	158	(210)	200
	3. Rupture discs	209	209	870	2,200	302	302	600	1,500
13. Sampling connection systems	Closed-purge sampling	41	41	1,200	1,200	59	59	820	820
14. Open-ended lines	Cap or plug	14	14	700	700	20	20	480	480

^a Further discussion of control techniques used can be found in Chapters 4 and 6 of the Background Information document (BID).

^b Average (mid-range) 1982 dollars per megagram (cost effectiveness) = net annual control cost per source ÷ annual benzene emission reduction per source. The values in parentheses denote a saving in costs.

^c Incremental dollars per megagram = (net annual cost of the control technique - net annual cost of the next less restrictive control technique) ÷ (annual emission reduction of control technique - annual emission reduction of the next less restrictive control technique). Values in parentheses denote savings.

^d Includes naphthalene processing.

^e Nineteen plants have direct-water final coolers, and 12 plants have tar-bottom final coolers.

The average cost effectiveness (the cost of control per megagram of emission reduction) was calculated by examining the cost effectiveness of each control option (i.e., the cost of going from an uncontrolled status to the level of control represented by a control option). Where more than one control option was available, EPA examined the incremental cost effectiveness. That is, EPA compared the more stringent level of control to the next less stringent level of control to evaluate the reasonableness of the additional cost incurred by the more stringent level of control in view of the additional benzene emission reduction that would be achieved. The incremental cost effectiveness between any two alternate control techniques was calculated as the difference in net annualized costs divided by the difference in the annual emission reductions of the alternate control techniques. If the incremental cost in comparison to the incremental emission reduction was judged as

unreasonable, then the next increment was examined until a control technique with a reasonable cost in comparison to the emission reduction was available. In all cases, EPA selected as BAT (considering costs) the control option that provided the most emission reduction and yet had a reasonable average and incremental cost per megagram of emission reduction.

It should be noted that the control costs do not represent the actual amounts of money spent at any particular plant site. Rather, the cost of emission reduction systems will vary according to the particular products produced, production equipment, plant layout and system design, geographic location, and company preferences or policies. However, these costs and emission reductions are considered typical of control techniques for benzene emission sources within coke by-product recovery plants. Although no construction of new by-product plants is expected during the next 5 years, new

sources could be constructed. Because new sources do not incur retrofit costs, the costs of control are generally less than for existing sources. However, the cost of control for new sources in by-product plants is not sufficiently less to warrant a separation examination of new source costs.

In Table 3, the emission sources for which gas blanketing was considered are grouped according to the most cost-effective approach for implementing this control technique. For example, the tar decanter, tar-intercepting sump, and flushing-liquor circulation tank are usually in close proximity. The most cost-effective system design for these (and other emission source groupings) would consist of the large header pipe from the collecting main to the general area of the sources. Smaller diameter piping would then connect the header pipe to each source to provide the blanketing gas.

EPA first examined the cost per unit of benzene emission reduction for all

sources for which only one control option was considered. These groups of sources include: (1) Tar decanters, tar-intercepting sumps, and flushing-liquor circulation tanks; (2) tar storage tanks and tar-dewatering tanks; (3) light/oil condensers, light-oil decanters, wash-oil decanters, and wash-oil circulation tanks; (4) light-oil sumps; (5) sampling connections; and (6) open-ended lines. The cost of control for these sources ranges from a net credit or cost savings to a high of \$1,200/Mg of benzene emission reduction. These costs are considered reasonable for the emission reduction achieved by the applicable control option. For this reason, these control options were tentatively selected as BAT, considering costs of control for each source. These control options include: (1) Use of the gas blanketing system for tar decanters, tar-intercepting sumps, flushing-liquor circulation tanks, tar storage tanks, tar-dewatering tanks, light-oil condensers, light-oil decanters, wash-oil decanters, and wash-oil circulation tanks; (2) a sealed cover for the light-oil sump; (3) closed-purge sampling for sampling connection systems; and (4) a cap or plug for open-ended lines.

EPA next examined two control options for naphthalene processing and final coolers: Wash-oil final coolers and tar-bottom final coolers. Wash-oil final coolers, the more effective of the two technologies, would virtually eliminate benzene emissions, applying this technology rather than tar bottom final coolers would result in an additional (incremental) benzene emission reduction of about 2,130 Mg/yr and an additional total emission reduction (including benzene and other VOC) of about 33,300 Mg/yr. The incremental annualized cost for wash-oil final coolers compared with tar bottom final coolers would be about \$37.2 million/yr. The incremental cost of wash-oil final coolers over tar bottom final coolers is \$18,000/Mg of benzene emission reduction, which is a relatively high incremental cost effectiveness. This relatively high incremental cost effectiveness is substantially reduced when the total emission reduction (including benzene and other VOC) is considered. However, the capital costs of the wash-oil final cooler system are also relatively high, ranging from \$2.1 million for a small model plant to \$7.9 million for a large model plant. An analysis of these capital costs compared to annual net income and investment indicated a potential for an unreasonably adverse economic impact on some firms. Based on a combination of all these cost-related factors, EPA

rejected the selection of wash-oil final coolers as BAT and selected tar bottom final coolers.

For storage tanks containing excess ammonia-liquor, light-oil, BTX, or benzene, EPA considered two control options—gas blanketing and wash-oil scrubbers. Gas blanketing of these sources would provide a benzene control efficiency of at least 93 percent, as compared to the 90-percent emission reduction provided by a wash-oil scrubber. The average cost per megagram of benzene emission reduction for gas blanketing of these sources ranges from about \$1,200/Mg to a high of about \$2,100/Mg; these costs are considered reasonable for the emission reduction achieved, especially considering that when the VOC emission reduction is added in, the average cost effectiveness is reduced to a range of about \$610/Mg to about \$1,700/Mg.

However, the wash-oil scrubber may be a viable option for these sources at some plants. A scrubber could be less expensive than gas blanketing. For this reason, EPA examined the nationwide incremental costs and emission reduction of 90 percent control with wash-oil scrubbers as compared to 93 percent control by gas blanketing.

For storage tanks containing light oil or benzene mixtures, the incremental cost associated with the gas blanketing option compared to the wash-oil scrubber option would be \$147,000/yr and the incremental benzene emission reduction would be 24 Mg/yr; this represents an incremental cost effectiveness of about \$6,100/Mg of benzene emission reduction. Furthermore, the use of gas blanketing would reduce total emissions (including benzene and VOC) by about 33 Mg/yr more than the wash-oil scrubber option; this represents an incremental cost effectiveness of about \$4,500/Mg of total emission reduction, including benzene and other VOC. Because the incremental cost effectiveness of gas blanketing for benzene (\$6,100/Mg) is relatively high and because the additional VOC emission reduction does not add enough weight to convince EPA that the costs are reasonable, EPA decided to tentatively select wash-oil scrubbers rather than gas blanketing as BAT, considering costs, for storage tanks containing light oil or benzene mixtures.

For storage tanks containing benzene, the incremental cost associated with gas blanketing (with nitrogen or natural gas) compared to the wash-oil scrubber option would be about \$45,000/yr and the incremental benzene emission reduction would be 6/Mg/yr; this

represents an incremental cost effectiveness of about \$8,100/Mg of benzene emission reduction. No emission reduction other than benzene would be achieved because benzene is the only organic emitted from this source. Because the incremental cost effectiveness of gas blanketing for benzene (\$8,100/Mg) is relatively high and because there is no additional VOC emission reduction that would be achieved by gas blanketing to convince EPA that the costs are reasonable, EPA tentatively selected wash-oil scrubbers as BAT, considering costs, for benzene storage tanks.

For storage tanks containing excess ammonia-liquor, the incremental cost associated with the gas blanketing option compared to the wash-oil scrubber option would be about \$34,000/yr and the incremental benzene emission reduction would be about 33 Mg/yr; this represents an incremental cost effectiveness of about \$2,900/Mg of benzene emission reduction. The use of gas blanketing would reduce total emissions (including benzene and VOC) by 49 Mg/yr more than the wash-oil final scrubber option; this represents an incremental cost effectiveness of about \$1,900/Mg of total emission reduction (including benzene and other VOC). Because the incremental cost effectiveness of gas blanketing for benzene (\$2,900/Mg) is relatively high and because the additional VOC emission reduction does not add enough weight to convince EPA that the costs are reasonable, EPA decided to tentatively select wash-oil scrubbers rather than gas blanketing as BAT, considering costs, for storage tanks containing excess ammonia-liquor.

Although the wash-oil scrubber was selected as the tentative BAT for these sources, some plants may prefer to apply gas blanketing due to site-specific factors or due to the potentially lower maintenance requirements. Because gas blanketing achieves a better control efficiency, the selection of the wash-oil scrubber as BAT would not preclude the use of gas blanketing (or any other control device that is designed and operated to achieve a 90-percent benzene control efficiency).

EPA considered three control options for pumps: Dual mechanical seal systems, monthly leak detection and repair, and quarterly leak detection and repair. (These are listed in order of decreasing control efficiency and cost.) EPA considered the most stringent option, dual mechanical seals, first. The incremental cost associated with the use of dual mechanical seal systems compared to the monthly leak detection

and repair option would be \$1.2 million/yr and the incremental benzene emission reduction would be 77 Mg/yr; this represents an incremental cost effectiveness of about \$16,000/Mg of benzene emission reduction. Furthermore, the use of dual mechanical seals would reduce total emissions (including benzene and other VOC) by 112 Mg/yr more than the monthly leak detection and repair option; this represents an incremental cost effectiveness of about \$11,000/Mg total emission reduction. Because the incremental cost effectiveness of dual mechanical seals for benzene (\$16,000/Mg) is relatively high and because the additional VOC emission reduction does not add enough weight to convince EPA that the costs are reasonable, EPA decided not to select dual mechanical seals as BAT, considering costs, for pumps.

Next, EPA considered monthly leak detection and repair. The incremental cost associated with monthly leak detection and repair compared with the quarterly leak detection and repair program would be about \$6,600/yr and the incremental benzene emission reduction would be 58 Mg/yr; this represents an incremental cost effectiveness of \$120/Mg benzene emission reduction. Because EPA considers the incremental cost effectiveness of monthly detection and repair reasonable and it gets more emission reduction than quarterly leak detection and repair, EPA decided to tentatively select monthly leak detection and repair as BAT, considering costs, for pumps.

EPA considered three control options for valves: Sealed bellows valves, monthly leak detection and repair, and quarterly leak detection and repair. EPA considered the most stringent option, sealed bellows valves, first. The incremental cost associated with the use of sealed bellows valves compared with monthly leak detection and repair is \$5.2 million/yr and the incremental benzene emission reduction would be 86 Mg/yr; this represents an incremental cost effectiveness of about \$61,000/Mg benzene emission reduction. Furthermore, the use of sealed bellows valves would reduce total emissions (including benzene and other VOC) by 123 Mg/yr more than monthly leak detection and repair; this represents an incremental cost effectiveness of about \$42,000/Mg. Because the incremental cost effectiveness of sealed bellows valves for benzene (\$61,000/Mg) is relatively high and because the additional VOC emission reduction does not add enough weight to convince EPA

the costs are reasonable, EPA decided not to select sealed bellows valves at BAT, considering costs, for valves.

Next, EPA considered monthly leak detection and repair. The incremental cost associated with monthly leak detection and repair compared with the quarterly leak detection and repair program would be \$20,200/yr and the incremental benzene emission reduction would be 30 Mg/yr; this represents an incremental cost effectiveness of \$670/Mg benzene emission reduction. Because a higher emission reduction would be achieved by monthly monitoring as compared to quarterly monitoring, at a reasonable cost, EPA tentatively selected monthly monitoring as BAT, considering costs, for valves.

For exhausters, the most stringent control option would require the use of degassing reservoir vents. This equipment would reduce benzene emissions by approximately 100 percent. The incremental cost of degassing reservoir vents over monthly inspections is \$568,000/yr and the incremental benzene emission reduction would be 9 Mg/yr; this represents an incremental cost effectiveness of about \$62,000/Mg. The use of this equipment would reduce total emissions (including benzene and other VOC) by about 38 Mg/yr more than the monthly inspection option, thereby reducing the overall incremental cost effectiveness to \$15,000/Mg total emission reduction (including benzene and other VOC). Because the incremental cost effectiveness of degassing vents for benzene control is relatively high and because the additional VOC emission reduction does not add enough weight to convince EPA that the costs are reasonable, degassing reservoir vents were not selected as BAT, considering costs, for exhausters.

Monthly inspections of exhausters would reduce benzene emissions by about 64 percent, or by about 2 Mg/yr more benzene than quarterly leak detection and repair. The incremental cost of monthly monitoring over quarterly monitoring is about \$24,000/yr; this represents an incremental cost effectiveness of about \$9,900/Mg of benzene emission reduction. Monthly inspections would reduce total emissions (including benzene and other VOC) by about 10 Mg/yr more than the total emission reduction achieved by quarterly monitoring; this reduces the overall cost effectiveness of this option to \$2,400/Mg total emission reduction (including benzene and other VOC). Because the incremental cost effectiveness of monthly inspections for benzene control is relatively high, and because the additional VOC emission

reduction does not add enough weight to convince EPA that the costs are reasonable, monthly monitoring was not selected as BAT, considering costs, for exhausters.

Quarterly inspections of exhausters would reduce benzene emissions by 14 Mg/yr at a cost of about \$17,300/yr. This represents a cost effectiveness of about \$1,300/Mg of benzene emission reduction. Furthermore, quarterly inspections would reduce total emissions (including benzene and other VOC) by about 59 Mg/yr; this reduces the overall cost effectiveness of this option to \$290/Mg total emission reduction (including benzene and other VOC). Because EPA considers the cost effectiveness of quarterly monitoring to be reasonable, particularly in view of the added VOC emission reduction, EPA tentatively selected quarterly monitoring as BAT, considering costs, for exhausters.

Of the control options considered for pressure relief devices, use of a rupture disc system would provide the greatest benzene emission reduction (approximately 100 percent). The incremental cost associated with the use of a rupture disc system compared to the monthly leak detection and repair option would be \$215,000/yr and the incremental benzene emission reduction would be 99 Mg/yr; this represents an incremental cost effectiveness of about \$2,000/Mg benzene emission reduction. Furthermore, the use of the rupture disc system would reduce total emissions (including benzene and other VOC) by 144 Mg/yr more than the monthly leak detection and repair option; this represents an incremental cost effectiveness of \$1,500/Mg total emission reduction. Because EPA considers the incremental cost effectiveness of the rupture disc system to be reasonable, particularly in view of the added VOC emission reduction, and because rupture disc systems get the most emission reduction, EPA tentatively selected that option as BAT, considering costs, for pressure relief devices.

Before making a final selection of control options as BAT, EPA considered the nonair quality environmental impacts and the economic and energy impacts to determine if the tentative selection of control options as BAT should be altered. Implementation of the control options tentatively selected as the basis of the proposed standard would reduce nationwide benzene emissions from coke by-product recovery plants from their current level of about 24,100 Mg/yr to about 2,700 Mg/yr, an overall emission reduction of

approximately 89 percent. Total uncontrolled nationwide emissions of benzene and other VOC's would be reduced from their current estimated level of 160,000 Mg/yr to about 35,000 Mg/yr, a 78-percent reduction.

No adverse environmental impacts are associated with these control options. Use of the gas blanketing system would actually tend to reduce the amount of benzene in process wastewater, in addition to solid waste disposal problems associated with sludge formation. Use of the gas blanketing system also provides the potential for fuel savings and increased product recovery. If the benzene in the recovered coke oven gas were used to underfire the coke oven battery, the national energy savings from the recovered gases would total about 30,000 terajoules (TJ) per year (0.028 quad/yr), assuming a recovery rate of 21.3 l of gas/min/Mg of coke per day. Further information detailing the development and consideration of these control techniques and the associated environmental and energy impacts, and the costs associated with each control option is presented in Chapters 6, 7, and 8 of the BID.

The total national capital and annualized costs of these control options also are considered to be reasonable. The total national capital costs associated with these control options are estimated at about \$23.8 million over the baseline (1982 dollars), including the cost of a monitor for leak detection. Light-oil recovery credits result in a savings in total annualized costs for furnace coke producers, as compared to the baseline. (Even though the controls selected as BAT may result in an annualized credit, in general, industries do not necessarily elect to install such controls in the absence of a regulation, because they might be able to attain a higher rate of return on their capital investment if given the opportunity to invest elsewhere.) The price of foundry coke could increase by as much as \$0.24/Mg, an increase of less than 1 percent from the baseline price, while the price of furnace coke would increase by less than \$0.02/Mg (1982 dollars). An economic analysis indicates that the industry trend is to pass through some increase in costs to consumers. Further information regarding the economic impacts of these control options is presented in Chapter 9 of the BID.

In summary, these control options were considered by EPA to have reasonable incremental costs per megagram of benzene emissions reduced. The environmental, energy,

and economic impacts are also positive or negligible. Less restrictive control options were not considered further because they would achieve less benzene emission reduction and because no cost, economic, energy, or nonair quality environmental impacts necessitated further examination of these less restrictive control options. The control options selected as BAT include: (1) A gas blanketing system for process vessels, and tar storage and dewatering tanks; (2) a wash-oil scrubber for storage tanks containing light oil, BTX, refined benzene, or excess ammonia-liquor; (3) the replacement of the direct-water final cooler with a tur-bottom final cooler or the conversion of the direct-water final cooler by the addition of a mixer-settler; (4) a scaled cover for the light-oil sump; (5) monthly monitoring for pumps and valves; (6) quarterly monitoring for exhausters; (7) a rupture disc system for pressure relief devices; (8) closed-purge sampling for sampling connections; and (9) caps or plugs for open-ended valves or lines.

After selecting these control options as BAT, EPA evaluated the estimated health risks remaining after application of BAT to determine if they were unreasonable in view of the estimated health risk reductions, costs, and economic impacts that would result if a more stringent regulatory alternative were applied. After the application of BAT, the annual leukemia incidence is estimated at about 0.19 case per year and the remaining maximum lifetime risk of acquiring leukemia is estimated at 3.0×10^{-4} for the most exposed group.

EPA considered the next most cost-effective control option beyond BAT—requiring storage tanks containing light oil, BTX, refined benzene, or excess ammonia-liquor to use a gas blanketing system, and requiring monthly monitoring for exhausters. Implementation of this control option would further reduce benzene emissions by about 65 Mg/yr. Requiring this higher level of control in lieu of BAT would not significantly change the estimated remaining leukemia incidence and the maximum lifetime risk. For this reason, the next more cost-effective control option beyond BAT was also examined.

The next more effective control option beyond BAT would be to require wash-oil final coolers, in addition to monthly monitoring for exhausters and gas blanketing for storage tanks containing light oil, BTX, refined benzene, or excess ammonia-liquor. This option would reduce benzene emissions by an additional 2,200 Mg/yr. This benzene emission reduction would result in a

reduction in the estimated leukemia incidence due to benzene exposure from coke by-product recovery plants from about 0.19 case per year at the BAT level to about 0.03 case per year. The estimated maximum lifetime risk would be reduced from 3.0×10^{-4} at the BAT level to about 2.4×10^{-4} at the beyond BAT level. This action would result in a total capital cost of \$131 million, and an incremental annualized cost of \$37.5 million/yr compared with BAT. The capital costs of this option, particularly those associated with the wash-oil final cooler system, would be relatively high on a per plant basis, ranging from \$2.1 million for a small model plant to \$7.9 million for a large model plant. These relatively high capital costs would also result in relatively high annualized costs on a per plant basis, ranging from \$0.7 million/yr for a small model plant to about \$3.2 million/yr for a large model plant. An analysis of these capital costs compared to annual net income and investment indicated a potential for an unreasonably adverse economic impact on some firms. Because of the relatively small health benefits to be gained with the additional costs and the potential adverse economic impacts on some firms of requiring the wash-oil final cooler option, EPA considers the risks remaining after application of BAT not to be unreasonable. For this reason, EPA judged the level of control selected as BAT to provide an ample margin of safety and decided not to require a more stringent level of control than BAT for coke by-product recovery plants.

Selection of Emission, Equipment, Work Practice, Design, and Operational Standards

Section 112 of the Clean Air Act requires that an emission standard be established for control of a hazardous air pollutant unless, in the judgment of the administrator, it is not feasible to prescribe or enforce such a standard. Section 112(e)(2) of the Act defines the following conditions under which it is not feasible to prescribe or enforce an emission standard: (1) If the pollutants cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant, or (2) if the application of measurement methodology is not practicable because of technological or economic limitations. Section 112(e)(1) allows that if an emission standard is not feasible to prescribe or enforce, then the Administrator may promulgate a design, equipment, work practice, or operational standard, or combination thereof.

The basis of the proposed standard selected for tar decanters, tar-

intercepting sumps, tar storage and dewatering tanks, flushing-liquor circulation tanks, light-oil condensers, light-oil decanters, wash-oil decanters, and wash-oil circulation tanks is a gas blanketing system. A gas blanketing system is not considered "leakless" equipment. Although this control technique could possibly achieve a 100-percent benzene control efficiency to meet a zero emissions limit when first installed, the gradual deterioration of sealing materials, even with proper operation and maintenance, could eventually result in vapor leaks. In addition, fugitive emissions may also be released from opening such as access hatches and sampling ports, which are necessary for proper operation and maintenance of the source. Emissions may also occur during emergency pressure-release episodes. Thus, a 100-percent emission reduction could not be achieved on a continuous basis.

Vapor leaks from the system cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant. For this reason, EPA has concluded that it is not feasible to prescribe or enforce an emission limit applicable to the gas blanketing system and has decided to propose for these sources a combination of equipment and work practices standard. The proposed equipment standard requires each affected source to be totally enclosed with emissions ducted to the gas collection system, gas distribution system, or other enclosed point in the by-product recovery process where the emissions will be recovered or destroyed. A positive-pressure system using dirty or clean coke oven gas, nitrogen, or natural gas as the gas blanket can be used. Pressure relief devices, vacuum relief devices, access hatches, and sampling ports would be the only openings allowed on each source, except for tar decanters. An additional opening to allow clearance for sludge conveyors would be permitted on tar decanters. However, the proposed standard would require that the access hatch and sampling port be equipped with a gasket and a cover or lid, which remains closed at all times to prevent the release of emissions, unless the hatch or port is actually in use.

Sections 112(e)(1) and 302(k) of the Clean Air Act require that design, equipment, work practice, and operational standards include provisions to ensure the proper operation and maintenance of the equipment. Use of gas blanketing on enclosed sources can be designed to be leakless; however, emissions could result if holes or other openings occur in

sealing material used on a source or the piping comprising the gas blanketing system. Gaps may also develop between a seal and the shell of a tank or other type of process vessel. Gaps can develop as a result of the deterioration of sealing materials, shell deformations, or the inability of a seal to conform to varying gaps because of a loss of seal flexibility.

To ensure proper operation and maintenance of the gas blanketing system, the proposed equipment standards would require the semiannual monitoring of all connections used on the control system and all sealing materials used to enclose the source for evidence of leaks. This would be performed using the test for "no detectable emissions" in Reference Method 21. An instrument reading indicating an organic chemical concentration greater than 500 ppm above a background concentration, as measured by Reference Method 21, would indicate the presence of a leak. As discussed in the section of this preamble entitled, "Selection of Performance Test Method," an organic chemical concentration of 500 ppm above a background concentration was selected as the leak definition for these sources, based on considerations relating to the calibration procedures and instrument capabilities. The owner or operator would also be required to conduct a semiannual visual check of each source and the ductwork of the control system for defects such as gaps or tears.

The proposed standard would also require that an initial attempt at repair of any leak or other defect detected by visual check or instrument monitoring be made within 5 days of detection. Repair of the leak or defect would be required within 15 days of the date of detection. The maintenance of records indicating the date of each inspection (instrument and visual), the equipment found to be leaking, and the date of repair would also be required. The cost of inspection of each source and control system would be about 1 person-hour. Because a low incidence of equipment failures is expected, requiring frequent inspections of the numerous sources at a typical plant would be unreasonable. For this reason, EPA decided to require that such inspections be conducted on a semiannual basis.

However, proper maintenance of the system is essential to ensure proper operation and, consequently, the effectiveness of the system. To help ensure proper maintenance, the proposed regulation requires an annual maintenance inspection for system

problems that could result in abnormal operation, such as plugging problems, sticking valves, or plugged condensate traps. The owner or operator would be required to make a first attempt at any necessary repairs within 5 days of detection, with repair within 15 days. If a system blockage should occur, the proposed regulation requires the owner or operator to conduct an inspection and make any necessary repairs immediately upon detection of the blockage. If a blockage or plugging problem were found, compressed air or a live steam purge could be used to clear the line. However, neither inspection should require a process shutdown.

A wash-oil scrubber with a 90-percent efficiency was selected as the basis of the proposed standard for storage tanks containing light oil, BTX, refined benzene, or excess ammonia-liquor. Fixed roof tank mass emissions vary considerably as a function of tank capacity and the utilization rate of the storage tank. Because of the wide variation in the amount of benzene vapors being emitted from the different types of storage tanks, a mass emission limit cannot be selected that would be achievable on a worst-case basis (i.e., large tank capacity, high vapor pressure, and high utilization rate), and at the same time would not allow the construction of control devices that are less effective than BAT. On this basis, EPA rejected any type of mass emission format for this section of the proposed standards.

The possibility of establishing an emission standard in a reduction efficiency format for storage tanks controlled by an add-on control device, such as a wash-oil scrubber, was then examined. Emissions from storage tanks are variable and are often at flow rates that are too low to measure. When liquid is entering a tank, the liquid surface rises, forcing vapors above the liquid surface out of the tank. While this is occurring, the vapor flow rate and the emissions are large. When liquid is exiting the tank, the liquid surface falls, and the resulting pressure differential sucks air or a blanketing material into the tank. During these operations, vapor flows into the storage tank resulting in no atmospheric emissions. When the liquid level is held constant, pressure differentials resulting from diurnal temperature variations expel vapors at very low flow rates at intermittent times during the cycle.

Certain components of uncontrolled emissions have been measured in very specialized tests conducted by the EPA and the petroleum industry. Total emissions have not been measured,

however, and to do so would require that the operation of the tank be strictly controlled during the testing period. Because of methodology problems, it may not be possible to measure both the flow rate and the concentration simultaneously. This would cast doubt on the accuracy of the measurement. For these reasons, it was concluded that it is impracticable to measure the emissions exiting the storage tank. For the same reasons, it would be impracticable to measure the emissions captured by the closed vent system connecting the control device to the source or entering the control device. Therefore, it was concluded that an emission standard in a reduction efficiency format is not feasible for control devices.

Because reduction efficiency cannot be measured practicably, it is infeasible to establish an emission standard requiring a percent reduction efficiency. A design standard requiring a reduction efficiency design specification, however, is feasible. The possibility of establishing a "design, equipment, work practice, or operational standard, or combination thereof" was, therefore, examined. A reduction efficiency design standard is advantageous in that it accounts for the wide variation in emission and flow rates being vented from the tank, and it would require the use of BAT control devices on all tanks. Therefore, the Administrator concluded that the standard for new and existing tanks storing light oil, benzene mixtures, benzene, or excess ammonia-liquor be a control system designed and operated to reduce emissions by 90 percent. The 90-percent design standard could be met using a wash-oil scrubber (or any other control system capable of achieving the 90-percent emission reduction, such as a gas blanketing system).

The proposed regulation would require that each tank be totally enclosed and sealed with emissions vented to the control device that is used to achieve compliance. Pressure relief devices, vacuum relief devices, access hatches, and sampling ports would be the only openings allowed on each tank. Each access hatch and sampling port must be equipped with a gasket and a cover or lid that is kept in a closed position when not in actual use. To ensure that the source and vent system are properly maintained so that emissions continue to be vented to the control device instead of being leaked to the atmosphere, the proposed standard would require the same work practices proposed for gas blanketed sources. That is, the proposed standard would require the semiannual monitoring of all seals or connections on the source and

vent for leaks using Reference Method 21, and visual check of the source and vent ductwork for defects such as gaps or tears. Also included would be the annual maintenance inspection for problems that could result in abnormal operation, such as plugging problems. The same provisions that are associated with these work practices for gas blanketed sources (for example, monitoring technique, repair provisions, recordkeeping, and reporting) would apply for these storage tanks.

To help ensure the proper operation and maintenance of the control device, the proposed standard also would include monitoring of parameters that indicate operation of the control device. For a wash-oil scrubber, the parameters that would need to be monitored to ensure proper operation and maintenance are the temperature of the gases exiting the scrubber, the wash-oil flow rate, and the pressure of the wash oil at the scrubber spray nozzle. Any drop in the wash-oil flow rate or pressure or any increase in the exit gas temperature as compared to the parameters specified in the design of the scrubber could indicate that a 90-percent emission reduction was not being achieved. A description of these occurrences would be included in the semiannual report.

The proposed standard for pressure relief devices is based on the installation of rupture discs upstream of the relief valve to prevent leaks. Measurement methods for determining the quantitative emission rate from pressure relief devices are not practicable because measurement would require the bagging of each device, which is an expensive procedure. Reference Method 21 does not provide for quantitative emission measurements, but does provide for the detection of leaks. Because fugitive emissions from pressure relief devices equipped with rupture discs would not be expected unless an overpressure release occurs, it is feasible to prescribe a "no detectable emissions" limit for pressure relief devices. An instrument reading of less than 500 ppm of organic compounds by volume above a background concentration, as measured by Reference Method 21, would indicate that fugitive emissions were below the "no detectable emissions" level.

The proposed emission limit would not apply to discharges during overpressure conditions because the function of the device is to discharge process gas, thereby reducing dangerous high pressures within the process. However, the proposed standard would specify that the device be returned to a

state of "no detectable emissions" within 5 days after such a discharge. The proposed standard would further require an annual test to verify the "no detectable emissions" status of each device, with records indicating the date of inspection, the equipment found to be leaking, and the date of repair.

As an alternative to the use of rupture discs and other techniques that achieve the "no detectable emissions" limit, EPA proposes to allow the venting of pressure relief devices to a control device designed and operated to achieve 95 percent efficiency. When venting a pressure relief device, the control device also reduces emission of benzene that occur during overpressure relief. EPA judges that the emission reduction lost by allowing 95 percent control of leaks (rather than the 100 percent control achieved by the "no detectable emissions" limit) is offset by the emission reduction gained by controlling the emissions due to overpressure relief. Steam-assisted and nonassisted flares designed for and operated with an exit velocity of less than 18 m/sec achieve better than 95 percent control efficiency and are potential control devices for this alternative standard. Therefore, provisions related to the use of flares are included in the proposed regulation. EPA has been studying the question of whether additional types of flares also will achieve better than 95 percent control efficiency; if so, the Agency will revise the standards accordingly.

The control technique selected as the basis of the proposed standard for light-oil sumps is a sealed cover that extends over the entire surface of the sump, coupled with the use of a gasket material applied to the rim of the sump cover. Such a sump cover would not be required to be permanently sealed because the cover may have to be removed for periodic maintenance. Eventual deterioration of the seal could result in leaks, even with proper operation and maintenance. These leaks could not reasonably be vented into a conveyance designed or constructed to capture the pollutant. Therefore, mass emissions from this source could not be measured.

The control techniques selected at BAT would allow the use of a vent on the light-oil sump cover so that excess pressure is not built up in the sump. Potential emissions from small pressure increases would be contained with the use of a water leg seal or a vent pipe equipped with a pressure relief device or a vacuum relief valve. Although the vent or vent pipe would provide a conveyance for the measurement of uncontrolled emissions, emission

measurement would still be impractical due to the low, intermittent emission rate. In addition, measurement methods for determining the quantitative emission rate from the pressure relief device on a vent are not practicable because the measurement would require the bagging of each device, which is an expensive procedure.

In addition, establishing a "no detectable emissions" limit would not necessarily ensure the control of emissions from the sump. Because the emissions are dispersed over a wide area, a "no detectable emissions" limit (< 500 ppm) could conceivably be met with no control device, even though the mass emissions from the sump would be greater without a cover than with a cover. For these reasons, EPA has concluded that an emission limit applicable to a light-oil sump is not feasible to prescribe or enforce, and has determined that establishment of an equipment standard is appropriate for this source.

To ensure proper operation and maintenance of the sump cover, the proposed equipment standard would require the semiannual inspection of the cover for "detectable" emissions (> 500 ppm VOC) using Reference Method 21. An initial attempt at repair of any defect or leak must be made within 5 days of the date of detection. Repair of the leak or defect would be required within 15 days of the date of detection.

The possibility of establishing an emission limit applicable to naphthalene processing was also considered. A process modification requiring the collection of naphthalene in tar (or an alternative medium such as wash oil) was selected as BAT for this emission source. Implementation of the process modification would eliminate naphthalene processing and the emissions that result from the practice of separating naphthalene from the hot well of a direct-water final cooler. Consequently, a "zero" emissions limit was selected for this process. A tar-bottom final cooler system or a wash-oil final cooler system could be used to eliminate naphthalene processing. If a direct-water final cooler is modified by the addition of a mixer-settler, the proposed standard would require that emissions be contained so that they are not released to the atmosphere. This requirement could be achieved by controlling emissions with a gas blanketing system. If a gas blanketing system were used, the mixer-settler would be subject to the proposed monitoring, reporting, and recordkeeping requirements applicable to other gas-blanketed sources.

Benzene emissions from open-ended lines occur as the result of leakage through the valve seat of a valve, which seals the open end of the line from the process fluid. The basis of the proposed standard is equipment that would enclose the open end of the line. Generally, open-ended lines are not designed to release fugitive emissions to a conveyance, and bagging of these sources for emission measurements would not be economically or technologically practicable. A "no detectable emissions" limit is not feasible to prescribe because benzene could leak through the valve seat and become trapped in the line between the open-ended valve and the cap. The trapped benzene could be emitted to the atmosphere, even though the benzene emitted to the atmosphere would be much less than the benzene emitted without the cap or enclosure. Because an emission limit was found to be infeasible to prescribe or enforce, EPA is proposing an equipment standard requiring that a cap, plug, blind, or a second valve be installed on open-ended lines.

To ensure the proper operation of the equipment, open-ended lines would also be covered by an operational standard. If a second valve is used the proposed standard would require the upstream valve to be closed first. After the upstream valve is completely closed, the downstream valve must be closed. This operational requirement is necessary to prevent trapping process fluid between the two valves, which could result in a situation equivalent to the uncontrolled open-ended valve.

As in the case of other equipment in benzene service, sampling connections are generally not designed to release fugitive emissions to a conveyance, and bagging of these emission sources would not be economically or technologically practicable. A "no detectable emissions" limit is not feasible because no available data indicate that application of any control technique would be able to comply with such a standard at all times.

Because an emission limit is considered infeasible to prescribe or enforce, an equipment standard requiring closed-purge sampling is proposed for sampling connections. Closed-purge sampling systems eliminate emissions caused by purging by either returning the purge material directly to the process or by collecting the purge in a collection system closed to the atmosphere. In-situ sampling would be exempted from these requirements.

Pumps, valves, and exhausters generally are not designed to release fugitive emissions into a conveyance. Because of the large number and diverse locations of pumps, valves, and exhausters, bagging of these sources for emission measurement would not be practicable or economical. Because these sources are expected to leak and because the control technology selected as the basis of the standard is a leak detection and repair program, a "no detectable emissions" limit is not appropriate to prescribe for these sources. EPA considers that the application of a "no detectable emissions" limit for these sources would reflect a control technology more stringent than BAT. For these reasons, a work practice standard was selected as the format for the proposed standards for these sources rather than an emission limit.

Three main factors influence the level of emission reduction that can be achieved by a leak detection and repair program—the monitoring interval, leak definition, and repair interval. Training and diligence of personnel conducting the program, repair methods attempted, and other site-specific factors may also influence the level of emission reduction achievable; however, these factors are less quantifiable than the three main factors. For each of these factors, the proposed standard includes control requirements which provide the most emission reduction without unreasonable costs or other burdens.

The monitoring interval is the frequency at which individual component monitoring is conducted. Monthly monitoring was selected as the required interval for pumps and valves, and quarterly monitoring was selected for exhausters; these intervals would provide the greatest emission reduction potential without imposing unreasonable costs or difficulties in implementing the leak detection and repair program.

The leak definition is the instrument reading observed during monitoring that would be used to determine which components have failed and need to be repaired. The best leak definition would be the one that achieved the most emission reduction at reasonable costs. The emission reduction achieved would increase as the leak definition decreased, due to the increasing number of sources that would be found leaking and, therefore, repaired. At a leak definition of 10,000 ppm organics, approximately 90 percent of benzene fugitive emissions from valves would be detected. Valves found leaking organic compounds at levels of 10,000 ppm or

greater can be brought to levels below 10,000 ppm with proper maintenance. Also, as a practical matter, most commonly available hydrocarbon detectors that are considered intrinsically safe have a maximum reading of 10,000 ppm. Leak definitions higher than 10,000 ppm could, nevertheless, be selected (and dilution probes could be used with portable detectors); however, there would be less emission reduction than with the 10,000-ppm definition and no substantial associated cost savings. Consequently, there is no basis for selecting a leak definition greater than 10,000-ppm organics. A leak definition lower than 10,000 ppm may be practicable in the sense that leaks can be repaired to levels less than 10,000 ppm. However, EPA is unable to conclude that a leak definition lower than 10,000 ppm, would provide additional emission reductions and, therefore, would be reasonable. Because the 10,000-ppm leak definition would address approximately 90 percent of the benzene fugitive emissions from valves at reasonable costs and at reasonable cost effectiveness, and because safe, available hydrocarbon detectors can read 10,000 ppm, the 10,000-ppm level was selected as the leak definition for valves. This definition is also considered appropriate for pumps and exhausters. The same portable monitor used for valves would be used for these sources, and consideration of other relevant factors did not indicate that the 10,000-ppm definition should be different for pumps or exhausters.

The repair interval is the length of time allowed between the detection of a leaking source and repair of the source. As noted above, to make the overall program effective, the most practicable selection for this factor should be chosen. Thus, to provide the maximum effectiveness of the leak detection and repair program, the repair interval should require expeditious reduction of emissions but should allow the owner or operator sufficient time to maintain some degree of flexibility in overall maintenance scheduling.

The length of the repair interval would affect emission reductions that are achievable by the leak detection and repair program because leaking sources would be allowed to continue to leak for a given length of time. Repair intervals of 1, 5, 15, 30, and 45 days were evaluated. The effect on the maximum emission reductions potential is proportional to the number of days the sources is allowed to leak between detection and repair.

Some pumps, valves, and exhausters may not be repairable by simple field maintenance. They may require spare parts or removal from the process for repair. Repair intervals of 1 to 5 days could cause problems in obtaining acceptable repair, especially when removal from the process would be required. However, a 15-day interval provides the owner or operator with sufficient time for flexibility in repair scheduling and provides time for better determination of methods for isolating pieces of leaking equipment for repair. In general, a 15-day repair interval allows more efficient handling of repair tasks while maintaining an effective reduction in fugitive emissions. Thus, the repair interval selected for proposal in the leak repair program is 15 days. A repair interval of 30 or 45 days was not selected because 15 days is a more restrictive, yet feasible, selection.

However, the first attempt at repair of a leaking source should be accomplished as soon as practicable after detection of the leak, but no later than 5 days after discovery. Most repairs can be done quickly, and 5 days should provide sufficient time to schedule maintenance and repair a leaking source. Attempting to repair the leak within 5 days will help to identify leaks that would require additional efforts so they could be repaired within the 15-day repair interval.

Delay of repair would be allowed for sources that could not be repaired without a process unit shutdown. These leaks would have to be repaired at the next unit shutdown unless the shutdown is unscheduled and lasts less than 24 hours. Delay of repair is not expected for most situations, however, because sources such as exhausters and critically situated pumps are commonly spared at by-product recovery plants. Therefore, they could be repaired without a process unit shutdown.

Monthly monitoring of valves to detect leaks is reasonable. However, some valves may leak less frequently than others. One indicator that might predict which valves leak is valve leak history. That is, once a valve leaks, then it may be more likely to leak again than a valve that has not leaked. The Administrator decided to implement the monthly monitoring requirement by focusing on the valves that tend to leak more often. One approach is to allow an alternative monitoring period for valves found to leak less frequently than others. The Administrator is proposing that leak detection and repair work practices include monthly monitoring for valves unless they are found not to leak for 2 successive months. If a valve is

found not to leak for 2 successive months, the owner or operator may elect to monitor during the first month of the next quarter and quarterly thereafter until a leak is detected. Whenever a leak is detected, the valve would be monitored once a month until the valve did not leak for 2 successive months.

Some valves are difficult to monitor because access to them is restricted. Therefore, EPA is proposing an annual leak detection and repair program for valves in existing process units that are difficult to monitor. Valves that are difficult to monitor are defined as valves that would require elevating the monitoring personnel more than 2 meters above any readily available support surface. This means that ladders must be used, if needed, to elevate monitoring personnel.

In addition to valves that are difficult to monitor, some valves are unsafe to monitor because monitoring personnel would be subject to imminent hazards. The proposed standards would allow an owner or operator with valves that are unsafe to monitor to develop a special leak detection and repair program. These special programs would conform with the routine monitoring requirements of the proposed standards as much as possible but would allow deviation from a routine monitoring so that monitoring would not occur under unsafe conditions. Valves that are unsafe to monitor are defined as those valves that could, as demonstrated by the owner or operator, expose monitoring personnel to imminent danger, e.g., hazards from temperature, pressure, or explosive process conditions. There should be few, if any, unsafe-to-monitor valves in benzene service in coke by-product recovery plants.

Pressure relief devices in liquid service and flanges and other connectors in all services would be excluded from the proposed routine leak detection and repair requirements on the basis of data from EPA testing. Screening studies done by EPA in coke by-product recovery plants indicated very low emission rates for individual flanges, which would result in only a small contribution to overall emissions. Testing of pressure relief devices in liquid service in petroleum refineries exhibited very low emission rates; similar results would be expected at coke by-product recovery plants. Applying routine monitoring requirements to these pieces of equipment would result in an exorbitant cost per megagram of emission reduction. However, if leaks are detected from these equipment, the

same allowable repair interval that applies to pumps, valves, and exhausters would apply.

The proposed regulation would also exclude equipment operating under a vacuum, because leaks to the atmosphere would not occur while the equipment is operating at subatmospheric internal pressures.

Alternative Standards for Valves. The emission reduction and annualized cost of the proposed leak detection and repair program depends in part on the number of valves that are found leaking during inspections. If very few leaks are detected in a plant, then the amount of benzene that could be reduced by the proposed program is much smaller than the amount that could be reduced in a plant that had more leaks. In contrast, the annualized cost of the program would be larger in a plant that had fewer leaks than in a plant that had more leaks because the annualized cost includes a recovery credit based on the amount of benzene recovered by the program. Therefore, the cost effectiveness of the proposed leak detection and repair program varies with the number of valves that leak within a plant.

There is no precise breakpoint in the emission reduction and annualized cost relationship as the percentage of leaking valves decreases. However, based on an analysis of coke by-product recovery plants, the Administrator has judged that the emission reduction and annualized cost relationship is unreasonable for plants having an average of less than 1 percent of valves leaking.

Based on this conclusion, the Administrator decided to propose alternative standards based on allowable percentage of valves leaking. The allowable percentage of valves leaking was chosen to include the variability inherent in any system; e.g., leak detection of valves. The variability in leak detection of valves can be characterized as a binomial distribution around the average number or percentage of valves leaking. Inclusion of the variability in leak detection of valves is accomplished by straightforward statistical techniques based on the binomial distribution. The analysis of by-product plants showed that an alternative standard of 2 percent of valves leaking, to be achieved at any time, would provide an owner or operator a reasonably low risk that a percentage of valves leaking greater than 2 percent would be determined when the average of 1 percent was actually being achieved.

Based on these considerations, the Administrator is proposing two

alternative standards that would exempt sources from the required (monthly/quarterly) leak detection and repair program if the sources achieve less than 2 percent leaking valves in benzene service. Owners or operators of affected facilities may identify and elect to achieve either of the alternative standards to allow tailoring of fugitive emissions control programs to their own operations. An owner or operator would report which alternative standard he or she had identified and elected to achieve.

The first alternative standard would limit the maximum percentage of valves in benzene service leaking to 2 percent. This type of standard would provide the flexibility of a performance standard. The first alternative standard could be achieved by the most efficient and practical methods for a particular plant. Choosing this alternative standard would allow for the possibility of different leak detection and repair programs and for the substitution of engineering controls at the discretion of the owner or operator. This standard would also eliminate a large part of the recordkeeping and reporting associated with the routine leak detection and repair program for valves.

An industry-wide allowable leak percent that could necessarily be achieved at all facilities is not possible for valves because of the variability in valve leak frequency and variability in the ability of a leak detection and repair program to reduce these leaks among all plants within the industry. However, this alternative standard would allow any plant the option of complying with an allowable percentage of valves leaking. This alternative standard would require a minimum of one performance test per year. Additional performance tests could be requested by EPA. If the results of a performance test showed a percentage of valves leaking higher than 2 percent, the process unit would not be in compliance with the standards.

The second alternative standard would allow the use of skip-period leak detection. Under skip-period leak detection, an owner or operator could skip from routine leak detection to less frequent leak detection after completing a number of successful leak detections. This skip-period leak detection program would require that the average performance level of 2 percent be achieved on a continuous basis with a reasonable degree of certainty. A plant would choose one of two skip-period leak detection programs and then implement that program. The first skip-period leak detection program could be used when fewer than 2 percent of the valves had been leaking for two

consecutive quarterly leak detection periods. The first skip-period leak detection program would allow an owner or operator to skip every other quarterly leak detection period; that is, leak detection can be performed semiannually. Under the second skip-period leak detection program, if fewer than 2 percent of the valves had been leaking for five consecutive quarterly leak detection periods, the owner or operator may skip three quarterly leak detection periods; that is, leak detection can be performed annually. When more than 2 percent of valves are found to leak, the routine leak detection and repair program would be required to be resumed.

Alternative Means of Emission Limitation

Under the provisions of section 112(o) of the Clean Air Act, if the Administrator establishes work practices, equipment, design or operational standards, then the Administrator must allow the use of alternative means of emission limitations if they achieve a reduction in air pollutants equivalent to that achieved under requirements of a standard. Sufficient data would be required to show equivalency, and a public hearing would be required.

Any person could request alternatives for specific requirements, such as the proposed equipment and the proposed leak detection and repair program. Under the proposed regulations, that person would be responsible for collecting and verifying the test data used to demonstrate that the alternative control techniques would be equivalent to the control techniques required by the standard. This information would then be submitted to EPA. If, in the Administrator's judgment, the alternative means of emission limitation would achieve a reduction in emissions at least equivalent to the reduction achieved under the design, equipment, work practice or operational standard, the Administrator would publish in the Federal Register, after notice and an opportunity for a hearing, a notice permitting the use of the alternative means for purposes of compliance with the standard.

To judge if an alternative control technique achieves an emissions reduction equivalent to gas blanketing, the Administrator would consider the control efficiency of gas blanketing as 98 percent for all sources except the tar decanter. For the tar decanter, the efficiency of gas blanketing would be considered as 95 percent. The lower efficiency is due to the opening that

must be on the tar decanter to allow clearance for the sludge conveyor.

Any control option more stringent than the option selected as the basis of the proposed standard would be at least equivalent to the requirements included in the proposed standard and would be allowed by EPA. EPA has already determined the equivalency of these control options and incorporated them into the standard, along with specified conditions for their use. Therefore, the owner or operator would not need to apply to EPA for their use as an alternative control option.

For example, the proposed standards would not require "leakless" equipment, such as sealed bellows and diaphragm valves and canned and diaphragm pumps. However, use of "leakless" equipment is clearly equivalent to the proposed standards for pumps, valves, and exhausters, and the proposed standards would allow the use of such equipment as an alternative to the required practices.

"Leakless" equipment would be required to operate with "no detectable emissions" at all times when it is in service. "No detectable emissions" means an instrument reading of 500 ppm or less of organic compounds above background, as measured by Reference Method 21. The proposed standards require that its "leakless" status be verified annually and at the request of the Administrator, using Reference Method 21.

In addition, other types of equipment can achieve emission reduction at least equivalent to that achieved by a monthly leak detection and repair program for pumps and a quarterly one for exhausters. For pumps, this equipment includes dual mechanical seal systems that use a barrier fluid between the two seals. For exhausters, this equipment includes a seal with a barrier fluid system. If the barrier fluid is maintained at a pressure greater than the pump or exhauster stuffing box pressure, any leakage would be from the barrier fluid to the working fluid; therefore, no working fluid would be emitted to the atmosphere. If the stuffing box pressure is greater than the barrier fluid pressure, the barrier fluid collects the leakage from the inner seal; the working fluid collected by the barrier fluid is controlled by either: (1) Connecting the barrier fluid degassing system to a control device, or (2) returning the barrier fluid to the process stream. Because these seal systems which meet these specifications are at least equivalent to a monthly leak detection and repair program for pumps and quarterly leak detection and repair program for exhausters, they have been

exempted from the monitoring provisions of the proposed standards.

Sections 112(e)(1) and 302(k) of the Clean Air Act require that when equipment standards are established, requirements must also be established to ensure the proper operation and maintenance of the equipment. A pressure or level indicator on the barrier fluid system would reveal any catastrophic failure of the inner or outer seal or of the barrier fluid system. This indicator would be monitored on a daily basis or equipped with an audible alarm to signal a failure of the system. The point at which the alarm signals a failure of the seal system would be determined for each seal system based on design considerations and operating experience. Thus, these requirements are proposed to ensure the proper operation and maintenance of the seal system.

In many cases, the seal area of a pump or exhauster could be completely enclosed, and this enclosed area could be connected to a control device designed and operated to achieve 95-percent control. Some owners or operators may decide that this approach is preferable to leak detection and repair. Enclosing the seal area and venting the captured emissions to a 95-percent control device is a reasonable alternative because this system would be at least as effective as the leak detection and repair programs for pumps and exhausters. Therefore, the Administrator is proposing to allow pumps and exhausters equipped with enclosed seal areas to be connected to a 95-percent control device.

Steam-assisted and nonassisted flares designed for and operated with an exit velocity of less than 18 m/sec achieve better than 95 percent control efficiency and are potential control devices for this alternative standard. Therefore, provisions related to the use of flares are included in the proposed regulation. EPA has been studying the question of whether additional types of flares also will achieve better than 95 percent control efficiency; if so, the Agency will revise the standards accordingly.

Selection of Test Method

Reference Method 21 (40 CFR Part 60, Appendix A) was selected as a method for measuring leaks from sources subject to the leak detection and repair requirements (including gas-blanketed sources) and for sources subject to "no detectable emissions" limits. The selection of this test method is fully discussed in the proposed new source performance standards for the control of VOC fugitive emissions in the synthetic organic chemicals manufacturing

industry (46 FR 1136, January 5, 1981) and proposed technical support document (EPA-450/3-80-033a). The method was promulgated on August 18, 1983 (46 FR 37593).

Reference Method 21 specifies the use of a portable detector to measure the concentration of organic vapors at a source to yield a qualitative or semiquantitative indication of the emission rate from the source. The test procedure does not detect benzene specifically; instead, the organic compound concentration is measured.

Tests have indicated that local conditions cause variations in concentration readings at points removed from the surface of the interface on the component where leaking occurs. Therefore, Reference Method 21 would require the concentration to be measured at the interface surface.

The monitoring instrument would be calibrated before each monitoring survey with methane or n-hexane. Thus, the required calibration gases would be a zero gas (air <10 ppmv volatile organic compounds) and an air mixture (approximately 10,000 ppm methane or n-hexane). If cylinder calibration gas mixtures were used, they would have to be analyzed and certified by the manufacturer to within ± 2 percent accuracy. Calibration gases prepared by the user according to an accepted gaseous standards preparation procedure would also have to be accurate to within ± 2 percent. The monitoring instrument would be subjected to other performance requirements prior to being placed in service for the first time. The instrument would be subjected to the performance criteria every 6 months and after any modification or replacement of the instrument detector.

The proposed standard also requires the ASTM Method D2267-68 ("Aromatics in Light Naphthas in Aviation Gasoline by Gas Chromatography") be used to determine the percentage of benzene in the process fluid within a fugitive emission source. This determination would be made only when the exact concentration of benzene is uncertain.

If a flare is used as a control device, Reference Method 22 of 40 CFR Part 60 shall be used to determine compliance with the "no visible emissions" requirement. The proposed standard specifies the use of Reference Method 2, 2A, or 2C of 40 CFR Part 60 to determine the volumetric flow rate of the flare. It also specifies the use of Reference Method 18 of 40 CFR Part 60 and ASTM Method D2504-67 to determine the

concentrations of the gas components in calculating the net heating value of the gas being flared. In addition, the heats of combustion of the gas may be determined using ASTS Method D2382-76, if published values are not available or cannot be calculated.

The ASTM Methods referenced above will be approved for incorporation by reference in 40 CFR 61.18 on the date of promulgation of the standard for benzene equipment leaks (fugitive emission sources) that was proposed on January 5, 1981 (46 FR 1165). Section 61.18 of 40 CFR Part 61 will be amended to include citations to the paragraphs specifying these ASTM Methods in this coke by-product plant standard when this standard is promulgated. The ASTM Methods are available for inspection at the Office of the Federal Register Information Center, Room 8401, 1100 L Street, N.W., Washington, D.C. 20408 and the Library (MD-35), U.S. EPA, Research Triangle Park, North Carolina 27711. They are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; or the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106.

Selection of Reporting and Recordkeeping Requirements

Recordkeeping would be required to document compliance with the proposed regulation; review of these records would provide information for plant and enforcement personnel to assess implementation of the requirements. Compliance would be determined by inspection and review of this recorded information.

For sources subject to equipment and design standards, such as gas-blanketed process units, the owner or operator must record and keep in a readily accessible location a description of the control systems to be used to achieve compliance (i.e., schematics), the installation date, and a description of any changes made after installation. This would also apply to equipment used to achieve compliance with the "zero" emissions limit for naphthalene processing. A record of design and operating specifications is also required for control devices used to achieve compliance.

The following records must be maintained for a least 2 years. For gas-blanketed sources, light-oil sumps, and storage tanks containing light-oil, benzene mixtures, benzene, or excess ammonia-liquor, records of the semiannual inspections must be maintained, including the inspection

date, the name of the inspector, a brief description of the leaks detected and repairs made, and the dates of repair attempts for each leak. The owner or operator must also maintain records of each annual maintenance inspection. These records must include a description of the abnormality, the repair made, and the repair dates. The proposed regulation also requires a record of any system blockage (or malfunction), with a brief description of the incident, the cause, the repairs made, and the repair dates.

For control devices, records must be maintained that indicate the dates the device was not operating as designed, the dates and description of any maintenance or repair of the device, and monitored parameters. If a wash-oil scrubber is used, the proposed regulation requires that records be kept of the wash-oil flow rate, the temperature of the gases exiting the scrubber, and the pressure at the scrubber spray nozzle. These records also must be maintained for at least 2 years.

Records of specific information pertaining to the leak detection and repair also would be required. Each source found to be leaking during the first month of a quarter would be identified with readily visible weatherproof identification bearing an identification (ID) number. The identification could be removed after the source had been repaired and monitored for leaks and repaired as necessary for the next 2 successive months. A log would be maintained for information pertaining to the leaking sources. The log would contain the instrument and operator identification numbers, the leaking source identification number, the date of detection of the leaking source, the date of the first attempt to repair the leaking source, repair methods applied in the first attempt to repair the source, and the date of final repair. The log would be kept for at least 2 years following the survey.

Reporting requirements are also included for enforcement personnel to review and assess the compliance status of affected sources. In the initial compliance report required by 40 CFR 61.10, the owner or operator must submit a statement notifying the Administrator that the requirements of the standard are being implemented, along with the other information required under § 61.10. If a waiver of compliance is granted under § 61.11, the statement would be submitted on a date scheduled by the Administrator. The statement also would describe the type of source and the method of compliance being used. For pieces of equipment in benzene

service, the statement would include the percent by weight benzene in the fluid and the process fluid state in the equipment (i.e., gas/vapor or liquid).

Semiannual reports starting 6 months after submission of the initial compliance report would be required. For gas-blanketed sources, light oil sumps, and storage tanks containing light oil, benzene mixtures, benzene, or excess ammonia-liquor, the report must contain a brief description of any visible defect in the source or ductwork, the number of leaks detected and repaired, and the repair dates. A brief description of any system abnormalities found during the annual maintenance inspection, the repairs made, and the repair dates also would be required, as would a brief description of any system blockage or malfunction incidents, the repairs made, and the repair dates.

The semiannual report also would include information regarding the use of control devices. Required information would include the date and time of any occurrence when the monitored parameters exceeded or drop below the parameter levels determined in the design specifications. If a wash-oil scrubber is used, the report must include the date and time of any occurrence when the wash-oil flow rate or the pressure at the scrubber spray nozzle falls below the parameter levels determined in the design specifications or the temperature of the gases exiting the scrubber exceeds the design specification temperature.

For pieces of equipment in benzene service, the semiannual report would include the process unit identification for the equipment, in addition to information regarding the number of pumps, valves, and exhausters for which leaks were detected during each month of the reporting period; the number of pumps, valves, and exhausters for which leaks were not repaired; an explanation of any delay of repairs; and dates of any process unit shutdowns that occurred during the reporting period.

Annual performance tests are required to verify the status of sources subject to "no detectable emissions" limits and for valves subject to the alternative standard. The proposed regulation requires the owner or operator to record the results of each performance test and to include this information in the semiannual report for that reporting period.

Each semiannual report also would include a statement signed by the owner or operator stating whether all provisions of the regulation has been fulfilled during the reporting period.

Alternative Approach for Selecting Emission Control Levels

Historically, EPA's approach to selecting control levels for emission sources has been a two-step process that included: (1) the selection of the best available technology (BAT) as the minimum control level, and (2) an evaluation of the incremental risk reductions and costs of more stringent controls. This approach was first outlined by EPA in the proposed Airborne Carcinogen Policy in 1979 (40 FR 58642) and has been generally followed by EPA since that time.

In selecting BAT for specific emission sources of coke by-product plants, EPA considered the cost per megagram of emission reduction for available control techniques. When more than one control option was available, EPA examined the incremental cost per megagram of moving to the more stringent control option. If the incremental cost in comparison to the incremental emission reduction was judged as unreasonable, the next lower increment was examined until a control technique with a reasonable cost in comparison to the emission reduction was available. In all cases, EPA selected as BAT the control option that provided the most emission reduction and yet has a reasonable average and incremental cost per megagram of emission reduction.

In proposing this approach, EPA recognizes that it usually gives somewhat limited and indirect weight to information on exposure and health risks in determining BAT and more direct weight to the amount of emissions reduced. For example, in determining BAT for emission sources, the Agency relies on estimates of the total emissions reduced and on estimates of the average and incremental cost of reducing those emissions. However, the Agency recognizes that emission estimates alone can sometimes be poor measures of public health risks because they do not account for the carcinogenic potency or exposure potential of hazardous air pollutant emissions.

In order to more directly consider health risks, the Agency intends to change the approach for selecting the appropriate control levels in the final standard for coke by-product plants. The new approach the Agency would use in the final standard would combine the current two-step process into one step. In selecting the appropriate control technique, EPA would consider in one step the before- and after-control risks, the health risk reduction, and the economic and societal costs of achieving those risk reductions. The major change in this approach would be the greater

consideration of public health risks over emission estimates in selecting controls.

EPA solicits comments on this intended approach.

Paperwork Reduction Act

An analysis of the burden associated with the reporting and recordkeeping requirements has been made. During the first 3 years of this regulation, the average annual burden of the reporting and recordkeeping requirements for the 42 existing coke by-product recovery plants would be about 3.3 person-years. The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* Comments on these requirements should be submitted to the Office of Information and Regulatory Affairs of OMB, marked "Attention: Desk Office for EPA." The final rule will respond to any OMB or public comments on the information collection requirements.

Regulatory Flexibility Analysis

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires the EPA to consider the potential impacts of proposed regulations on small "entities." The guidelines for conducting a regulatory flexibility analysis define a small business as "any business concern which is independently owned and operated and not dominant in its field as defined by the Small Business Administration Regulations under Section 3 of the Small Business Act." For the purposes of this proposed regulation, small "entities" are considered to be small furnace and foundry coke firms that employ less than 1,000 workers.

A regulatory flexibility analysis identifies up to six small foundry coke plants that could be affected by the proposed regulation. Present guidelines for the analysis require an estimate of the degree of economic impact on the firms in terms of: (1) the percent increase in the average total cost of producing coke as a result of the proposed standard, and (2) the total annual cost of control as a percentage of the firm's revenue. If the percent increase in the average total cost of producing coke is estimated as 5 percent or more, the impact of the proposed regulation is to be considered significant. If the total annual cost of control as a percentage of the firm's annual revenue is 10 percent greater for small firms than for large firms, the small firms are to be considered adversely impacted by the proposed standard.

None of the firms identified as small firms were found to have an average coke production cost increase greater than 5 percent. In addition, none of these plants exceeded the second criterion. In summary, no small plants would be adversely affected by the proposed standard. A further discussion of the regulatory flexibility analysis is provided in Chapter 9 of the background information document.

Public Hearing

A public hearing will be held to discuss the proposed standard for coke by-product recovery plants in accordance with sections 112(b)(1)(B) and 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations on the proposed standards for benzene emissions from coke by-product recovery plants should contact EPA at the address given in the ADDRESSES section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 75 days after the hearing. Written statements should be addressed to the Central Docket Section address given in the ADDRESSES section of this preamble and should refer to Docket Number A-79-16.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (see ADDRESSES section of this preamble).

Docket

The docket is an organized and complete file of all the information submitted to, or otherwise considered by, EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) To allow interested parties to effectively participate in the rulemaking process; and (2) to serve as the record in case of judicial review except for interagency review materials [307(d)(7)(A)]

Miscellaneous

In accordance with section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues.

Under Executive Order 12291, EPA is required to judge if a regulation is a "major rule" and, therefore, subject to certain requirements of the Executive

Order. The Agency has determined that this regulation would result in none of the adverse economic effects set forth in section 1 of the Executive Order as grounds for finding a regulation to be a "major rule." A savings in industry-wide annualized costs, resulting from benzene recovery credits, would be achieved by the proposed standard. For furnace coke producers, the impacts of the proposed standard would result in only a negligible price increase; the price of foundry coke is expected to increase by less than 1 percent. The Agency has also concluded that this rule is not "major" under any of the criteria established in the Executive Order. Therefore, the Agency has concluded that the proposed regulation is not a "major rule" under Executive Order 12291.

This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA responses to those comments are available for inspection in Docket Number A-79-16, Central Docket Section, at the address given in the ADDRESSES section of this preamble.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 61

Asbestos, Beryllium, Hazardous substances, Mercury, Reporting and recordkeeping requirements, Vinyl chloride

Dated: May 23, 1984.

William D. Ruckelshaus,
Administrator.

PART 61—[AMENDED]

It is proposed that Part 61 of Chapter I, Title 40, of the Code of Federal Regulations be amended by adding a new Subpart L, as follows:

Subpart L—National Emission Standard for Benzene Emissions From Coke By-Product Recovery Plants

Sec.

- 61.130 Applicability and designation of sources.
- 61.131 Definitions.
- 61.132-1 Standards: General.
- 61.132-2 Standards: Process vessels, tar storage tanks, and tar-intercepting sumps.
- 61.132-3 Standards: Light-oil sumps.
- 61.132-4 Standards: Light-oil, benzene, and excess ammonia-liquor storage tanks.
- 61.132-5 Standards: Naphthalene processing.
- 61.132-6 Standards: Pumps.
- 61.132-7 Standards: Exhausters.

Sec.

- 61.132-8 Standards: Pressure relief devices in gas/vapor service.
- 61.132-9 Standards: Sampling connection systems.
- 61.132-10 Standards: Open-ended valves or lines.
- 61.132-11 Standards: Valves.
- 61.132-12 Standards: Pressure relief devices in liquid service and flanges and other connectors.
- 61.132-13 Standards: Delay of repair for equipment leaks.
- 61.132-14 Standards: Closed vent systems and control devices for equipment leaks of benzene.
- 61.133-1 Alternative standards for valves in benzene service—allowable percentage of valves leaking.
- 61.133-2 Alternative standards for valves in benzene service—skip period leak detection and repair.
- 61.134 Alternative means of emission limitation.
- 61.135 Test methods and procedures.
- 61.136 Recordkeeping requirements.
- 61.137 Reporting requirements.

Authority: Secs. 112 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7412 and 7601(a)), and additional authority as noted below.

Subpart L—National Emission Standard for Benzene Emissions From Coke By-Product Recovery Plants

§ 61.130 Applicability and designation of sources.

(a)(1) The provisions of this subpart apply to each of the following sources in a coke by-product recovery plant: naphthalene processing and direct-water final-cooler cooling systems; tar decanters; tar-dewatering tanks; tar-intercepting sumps; flushing-liquor circulation tanks; light-oil sumps; light-oil condensers; light-oil decanters; wash-oil decanters; wash-oil circulation tanks; and each storage tank containing tar, light-oil, benzene, or excess ammonia-liquor.

(2) The provisions of this subpart also apply to each of the following sources in a coke by-product recovery plant that are intended to operate in benzene service: pumps, valves, exhausters, pressure relief devices, sampling connection systems, open-ended valves or lines, flanges and other connectors, and control devices or systems required by this subpart.

§ 61.131 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in Subpart A of Part 61, and the following terms shall have the specific meanings given them:

"Benzene storage tank" means any tank, reservoir, or other type container used to collect or store refined benzene.

"Closed-vent system" means a system that is not open to atmosphere and that

is composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device.

"Coke by-product recovery plant" means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

"Connector" means flanged, screwed, welded, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment.

"Control device" means an enclosed combustion device, vapor recovery system, or flare.

"Double block and bleed system" means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

"Equipment" means each pump, valve, exhauster, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in benzene service, and any devices or systems required by § 61.132-14.

"Excess ammonia-liquor storage tank" means any tank, reservoir, or other type container used to collect or store a flushing-liquor solution prior to ammonia or phenol recovery.

"First attempt at repair" means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere, using best practices.

"Flushing-liquor circulation tank" means any vessel that functions to store or contain flushing liquor that is separated from the tar in the tar decanter and is recirculated as the cooled liquor to the gas collection system.

"In benzene service" means a piece of equipment, other than an exhauster, that either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight or any exhauster that either contains or contacts a fluid (liquid or gas) at least 1 percent benzene by weight as determined by the provisions of § 61.135(d). The provisions of § 61.135(d) also specify how to determine that a piece of equipment is not in benzene service.

"In gas/vapor service" means that a piece of equipment contains process fluid that is in the gaseous state at operating conditions.

"In vacuum service" means that a process unit (including associated equipment) is operating at an internal pressure that is at least 5 kilopascals (kPa) below ambient pressure.

"In VOC service" means, for the purposes of this subpart, that: (1) The piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight; and (2) the piece of equipment is not in light liquid service as defined in 40 CFR 60.481. See 40 CFR 60.2 for the definition of volatile organic compound or "VOC" and 40 CFR 60.485(d) to determine whether a piece of equipment is not in VOC service.

"In-situ sampling systems" means nonextractive samplers or in-line samplers.

"Light-oil condenser" means any vessel, tank, or other type device in the light-oil recovery operation that functions to condense benzene-containing vapors.

"Light-oil decanter" means any vessel, tank, or other type device in the light-oil recovery operation that functions to separate light oil from the coke oven gas process stream. A light-oil decanter may also be known as a light-oil separator.

"Light-oil storage tank" means any vessel, tank, reservoir, or other type of container used to collect or store crude light oil or light-oil fractions such as benzene-toluene-xylene (BTX) mixtures.

"Light-oil sump" means any tank, pit, enclosure, or slop tank in light-oil recovery operations that functions as a wastewater separation device to recover hydrocarbon liquids from the surface of the water.

"Mixer-settler" means a tank containing tar that is inserted into the final cooling process of a direct-water final cooler system that serves to remove naphthalene from the direct-contact water.

"Naphthalene processing" means any operations required to recover naphthalene from a direct-water final cooler, including the separation, refining, drying, handling, and transporting of crude or refined naphthalene.

"Open-ended valve or line" means any valve, except pressure relief devices, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

"Pressure release" means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

"Process unit" means each group of process vessels and equipment assembled to produce, as intermediate or final products, any by-product evolved from coal in a coke by-product recovery plant (e.g., the light-oil plant). A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient product storage facilities.

"Process unit shutdown" means a work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

"Process vessel" means each tar decanter, flushing-liquor circulation tank, light-oil condenser, light-oil decanter, wash-oil decanter, or wash-oil circulation tank.

"Quarter" means a 3-month period, the first quarter concludes on the last day of the last full month during the 180 days following startup for new sources; the first quarter concludes on the last day of the last full month during the 180 days after (date of publication of final rule in Federal Register) for existing sources.

"Repaired" means that a source is adjusted or otherwise altered in order to eliminate a leak as indicated by one of the following: an instrument reading of 10,000 ppm or greater, instrument reading of 500 ppm or greater above a background concentration, indication of liquids dripping, or indication by a sensor that a seal system or barrier fluid system has failed.

"Semiannual" means a 6-month period; the first semiannual period concludes on the last day of the last full month during the 180 days following initial startup for new sources; and the first semiannual period concludes on the last day of the last full month during the 180 days after (date of publication of final rule in Federal Register) for existing sources.

"Sensor" means a device that measures a physical quantity or the change in a physical quantity, such as temperature, pressure, flow rate, pH, or liquid level.

"Tar decanter" means any vessel, tank, or other type container that functions to separate heavy tar and sludge from flushing liquor by means of gravity, heat, or chemical emulsion breakers. A tar decanter may also be known as a flushing-liquor decanter.

"Tar storage tank" means any vessel, tank, reservoir, or other type container used to collect or store crude tar or tar-entrained naphthalene except for tar products obtained by distillation, such as coal tar pitch, creosotes, or carbolic oil. This definition also includes any vessel, tank, reservoir, or other type container used to reduce the water content of the tar by means of heat,

residence time, chemical emulsion breakers, or centrifugal separation. A tar storage tank may also be known as a tar-dewatering tank.

"Tar-intercepting sump" means any tank, pit, or enclosure that serves to separate light tars and aqueous condensate received from the primary cooler. A tar-intercepting sump may also be known as a primary-cooler decanter.

"Wash-oil circulation tank" means any vessel that functions to hold the wash oil used in light oil recovery operations or the wash oil used in the wash-oil final cooler.

"Wash-oil decanter" means any vessel that functions to separate, by gravity, the condensed water from the wash oil received from a wash-oil final cooler or from a light-oil scrubber.

§ 61.132-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of § 61.132 for each new and existing source, except as provided in § 61.133 and § 61.134.

(b) Compliance with this subpart will be determined by review of records, review of performance test results, and inspection using the methods and procedures specified in § 61.135.

(c)(1) An owner or operator may request permission to use an alternative means of emission limitation to meet the requirements of §§ 61.132-2, 61.132-3, 61.132-6, 61.132-7, 61.132-9, 61.132-10, 61.132-11, 61.132-12, 61.132-13, and 61.132-14. Permission to use an alternative means of emission limitation may be requested as specified in § 61.134.

(2) If the Administrator permits the use of an alternative means of emission limitation to meet the requirements of §§ 61.132-2, 61.132-3, 61.132-6, 61.132-7, 61.132-9, 61.132-10, 61.132-11, 61.132-12, 61.132-13, or 61.132-14, an owner or operator shall comply with the conditions of that permission.

(d) Each piece of equipment in benzene service to which this subpart applies shall be marked in such a manner that it can be distinguished readily from other pieces of equipment in benzene service.

(e) Equipment that is in vacuum service is excluded from the requirements of this subpart if it is identified as required in § 61.136(h)(5).

(f) At all times, owners and operators shall, to the extent practicable, maintain and operate any source including associated air pollution control equipment, according to good air pollution control practice for minimizing emissions. Determining whether

acceptable operating and maintenance procedures are used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the source.

§ 61.132-2 Standards: Process vessels, tar storage tanks, and tar intercepting sumps.

(a)(1) Each owner or operator shall enclose and seal all openings on each process vessel, tar storage tank, and tar intercepting sump.

(2) The owner or operator shall duct gases from each source to the gas collection system, gas distribution system, or other enclosed point in the by-product recovery process where the benzene in the gas will be recovered or destroyed. This control system shall be designed and operated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background and by visual inspections, as determined by the methods specified in § 61.135(c). This system can be designed as a closed, positive-pressure, gas blanketing system.

(i) Except, the owner or operator may elect to install, operate, and maintain a pressure relief device, vacuum relief device, an access hatch, and a sampling port on each source. Each access hatch and sampling port must be equipped with a gasket and a cover, seal, or lid that must be kept in a closed position at all times, unless in actual use. and

(ii) The owner or operator may elect to leave open to the atmosphere the portion of the liquid surface in each tar decanter necessary to permit operation of a sludge conveyor. If the owner or operator elects to maintain an opening on part of the liquid surface of the decanter, the owner or operator shall install, operate, and maintain a water seal on the tar decanter roof near the sludge discharge chute to ensure enclosure of the major portion of the liquid surface not necessary for the operation of the sludge conveyor.

(b) Following the installation of any control equipment used to meet the requirements of paragraph (a) of this section, the owner or operator shall monitor semiannually the connections and seals on each control system to determine if it is operating with no detectable emissions, using Reference Method 21 (40 CFR Part 60, Appendix A) and procedures specified under § 61.135(c) of this subpart. The owner or operator shall also conduct semiannually a visual inspection of each source (including sealing materials) and the ductwork of the control system for

evidence of visible defects such as gaps or tears.

(1) If an instrument reading indicates an organic chemical concentration more than 500 ppm above a background concentration, as measured by Reference Method 21, a leak is detected.

(2) If visible defects such as gaps in sealing materials are observed during a visual inspection, a leak is detected.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected.

(4) A first attempt at repair of any leak or visible defect shall be made no later than 5 calendar days after each leak is detected.

(c) Following the installation of any control system used to meet the requirements of paragraph (a) of this section, the owner or operator shall conduct a maintenance inspection of the control system on an annual basis for evidence of system abnormalities, such as blocked or plugged lines; sticking valves, plugged condensate traps, and other maintenance defects that could result in abnormal system operation.

The owner or operator shall make a first attempt at repair within 5 days, with repair within 15 days of detection. If a system blockage occurs at any time, the owner or operator shall conduct an inspection and perform any necessary repairs immediately upon detection.

§ 61.132-3 Standards: Light-oil sumps.

(a) Each owner or operator of a light-oil sump shall enclose and seal the liquid surface in the sump to form a closed system to contain the emissions.

(1) Except, the owner or operator may elect to install, operate, and maintain a vent on the light-oil sump cover. Each vent pipe must be equipped with a water leg sea, a pressure relief device, or vacuum relief device; and

(2) The owner or operator may elect to install, operate, and maintain an access hatch on each sump cover. Each access hatch must be equipped with a gasket and a cover, seal, or lid that must be kept in a closed position at all times, unless in actual use.

(3) The sump cover may be removed for periodic maintenance but must be replaced (with seal) at completion of the maintenance operation.

(b) The venting of steam or other gases from the by-product process to the light-oil sump is not permitted.

(c) Following the installation of any control equipment used to meet the requirements of paragraph (a) of this section, the owner or operator shall monitor semiannually the connections and seals on each control system to determine if it is operating with no

detectable emissions, using Reference Method 21 (40 CFR Part 60, Appendix A) and the procedures specified under § 61.135(c) of this subpart. The owner or operator shall also conduct on a semiannual basis a visual inspection of each source (including sealing materials) and the ductwork of the control system for evidence of visible defects such as gaps or tears.

(1) If an instrument reading indicates an organic chemical concentration more than 500 ppm above a background concentration, as measured by Reference Method 21, a leak is detected.

(2) If visible defects such as gaps in sealing materials are observed during a visual inspection, a leak is detected.

(3) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected.

(4) A first attempt at repair of any leak or visible defect shall be made no later than 5 calendar days after each leak is detected.

§ 61.132-4 Standards: Light-oil, benzene, and excess ammonia-liquor storage tanks.

(a)(1) Each storage tank containing light-oil benzene, or excess ammonia-liquor shall be equipped with a control device designed and operated to achieve a 90-percent benzene control efficiency.

(2) Each owner or operator shall enclose and seal all openings on each tank; the gases from each tank shall be ducted to the control device used to achieve compliance with paragraph (a)(1) of this section.

(3) The owner or operator may elect to install, operate, and maintain a pressure relief device, vacuum relief device, an access hatch, and a sampling port on each tank. Each access hatch and sampling port must be equipped with a gasket and a cover, seal, or lid that must be kept in a closed position at all times, unless in actual use.

(b) Following the installation of any control equipment used to meet the requirements of paragraph (a) of this section, the owner or operator shall monitor semiannually the connections and seals on each tank to determine if the control system is operating with no detectable emissions, using Reference Method 21 (40 CFR Part 60, Appendix A) and procedures specified under § 61.135(c) of this subpart. The owner or operator shall also conduct semiannually a visual inspection of each tank (including sealing materials) and the ductwork to the control device for evidence of visible defects such as gaps or tears.

(1) If an instrument reading indicates an organic chemical concentration more

than 500 ppm above a background concentration, as measured by Reference Method 21, a leak is detected.

(2) If visible defects such as gaps in sealing materials are observed during a visual inspection, a leak is detected.

(3) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected.

(4) A first attempt at repair of any leak or visible defect shall be made no later than 5 calendar days after each leak is detected.

(c) Following the installation of any control device (or control system) used to meet the requirements of paragraph (a) of this section, the owner or operator shall conduct a maintenance inspection of the connections and seals on each tank and ductwork to the control device on an annual basis for evidence of system abnormalities, such as blocked or plugged lines, sticking valves, plugged condensate traps, and other maintenance defects that could result in abnormal system operation. The owner or operator shall make a first attempt at repair within 5 days, with repair within 15 days of detection. If a system blockage occurs at any time, the owner or operator shall conduct an inspection and perform any necessary repairs immediately upon detection.

(d)(1) The owner or operator shall monitor parameters that indicate proper operation of the control device to ensure that the device is operated and maintained in conformance with the design. The selection of monitoring parameters is subject to approval by the Administrator.

(2) If a wash-oil scrubber is used as the control device, the owner or operator shall install, operate, calibrate, and maintain a device to monitor and record the wash-oil flow rate, the temperature of the gases exiting the scrubber, and the pressure of the wash oil at the scrubber spray nozzle.

(e) The ducting of gases (e.g., coke oven gas, natural gas or nitrogen used as a blanketing agent) from a storage tank to the gas collection system, gas distribution system, or another enclosed point in the by-product recovery process where the benzene in the gas will be recovered or destroyed is permitted for compliance with the standard specified in paragraph (a) of this section.

(f) An owner or operator ducting gases from a tank in the manner described in paragraph (e) of this section shall comply with all requirements specified in § 61.132-2, including leak detection and repair provisions.

(g) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the

extent practicable, maintain and operate any source, including associated air pollution control equipment, according to good air pollution control practice for minimizing emissions. Determining whether acceptable operating and maintenance procedures are used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the source.

§ 61.132-5 Naphthalene processing.

(a) No ("zero") emissions are allowed from naphthalene processing.

(b) The emission limit specified in paragraph (a) of this section is not applicable if a mixer-settler is used to separate naphthalene from the water of a direct-water final cooler by tar or another organic liquid.

(c) If a mixer-settler is used to separate naphthalene from the water of a direct-water final cooler, the mixer-settler is subject to all requirements specified in § 61.132-2 for process vessels, including leak detection and repair provisions.

§ 61.132-6 Standard: Pumps.

(a)(1) Each pump shall be monitored monthly to detect leaks by the methods specified in § 61.135(b), except as provided in § 61.132-1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump shall be checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 61.132-13.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section provided the following requirements are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is connected by

a closed-vent system to a control device that complies with the requirements of § 61.132-14; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero benzene emissions to the atmosphere.

(2) The barrier fluid system is not in benzene service and if the pump is covered by the standards in 49 CFR Part 60, subpart VV, it is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(5)(i) Each sensor as described in paragraph (d)(3) of this section is checked daily or is equipped with an audible alarm, and

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criteria determined in paragraph (d)(5)(ii) of this section, a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 61.132-13.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated as described in § 61.135(h)(2) for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing.

(2) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 61.135(c), and

(3) Is tested for compliance with paragraph (c)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of § 61.132-14, it is exempt from the

requirements of paragraphs (a)-(e) of this section.

§ 61.132-7 Standards: Exhausters.

(a) Each exhauster shall be monitored quarterly to detect leaks by the methods specified in § 61.135 except as provided in § 61.132-1(c) and paragraphs (d)-(f) of this section.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 61.132-13. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each exhauster equipped with a seal system that includes a barrier fluid system and that prevents leakage of process fluids to atmosphere is exempt from the requirements of paragraphs (a) and (b) of this section provided the following requirements are met:

(1) Each exhauster seal system is:

(i) Operated with the barrier fluid at a pressure that is greater than the exhauster stuffing box pressure; or

(ii) Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of § 61.132-14; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero benzene emissions to the atmosphere.

(2) The barrier fluid system is not in benzene service and if the exhauster is covered by standards in 40 CFR Part 60, Subpart VV, it is not in VOC service.

(3) Each barrier fluid system shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(4)(i) Each sensor as described in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(ii) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both

(5) If the sensor indicates failure of the seal system, the barrier system, both based on the criterion determined under paragraph (d)(4)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 61.132-13.

(ii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) An exhauster is exempt from the requirements of paragraphs (a) and (b) of this section if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device and that complies with the requirements of § 61.132-14, except as provided in paragraph (f) of this section

(f) Any exhauster that is designated, as described in § 61.136(i)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)-(e) of this section if the exhauster:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 61.135(c); and

(2) Is tested for compliance with paragraph (f)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

§ 61.132-8 (Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 61.135(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after each pressure release.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 61.135(c).

(c) Any pressure relief device that is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 61.132-14 is exempt from the requirements of paragraphs (a) and (b) of this section

§ 61.132-9 Standards; Sampling connection systems

(a) Each sampling connection system shall be equipped with a closed purge

system or closed vent system, except as provided in § 61.132-1(c).

(b) Each closed purge or closed vent system as required in paragraph (a) shall:

(1) Return the purged process fluid directly to the process line with zero benzene emissions to the atmosphere; or

(2) Collect and recycle the purged process fluid with zero benzene emissions to the atmosphere; or

(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of § 61.132-14.

(c) In-situ sampling systems are exempt from paragraphs (a) and (b) of this section.

§ 61.132-10 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 61.132-1(c).

(2) The cap, blind flange, plug, or second valve seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block and bleed system is used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

§ 61.132-11 Standards: Valves.

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in § 61.135(b) and shall comply with paragraphs (b)-(e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 61.132-1(c), and § 61.133-1 or § 61.133-2.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after the leak is detected, except as provided in § 61.132-13.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

- (1) Tightening of bonnet bolts;
- (2) Replacement of bonnet bolts;
- (3) Tightening of packing gland nuts;
- (4) Injection of lubricant into

lubricated packing.

(f) Any valve that is designated, as described in § 61.136 (1)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background, as determined by the method specified in § 61.135(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 61.136(i)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 61.136(i)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The equipment within which the valve is located is an existing process unit, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 61.132-12 Standards: Pressure relief devices in liquid service and flanges and other connectors.

(a) Pressure relief devices in liquid service and flanges and other connectors shall be monitored within 5 days by the method specified in

§ 61.135(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 61.132-13.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under § 61.132-11(e).

§ 61.132-13 Standards: Delay of repair for equipment leaks.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in benzene service.

(c) Delay of repair for valves will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed in a control device complying with § 61.132-14.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair for exhausters will be allowed if:

(1) Repair requires the use of a seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(f) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the

next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

§ 61.132-14 Standards: Closed vent systems and control devices for equipment leaks of benzene.

(a) Owners or operators of closed vent systems and control devices used to comply with the provisions of § 61.132-6 (d) or (f), § 61.132-7 (d) or (e), § 61.132-8(c), or § 61.132-9(b) shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the benzene vapors vented to them with an efficiency of 95 percent or greater.

(c) Enclosed combustion devices shall be designed and operated to reduce the benzene emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.50 seconds at a minimum temperature of 760° C.

(d)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in § 61.135(e) except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall operate with a flame present at all times, as determined by the methods specified in § 61.135(e).

(3) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in § 61.135(e).

(4) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the method specified in § 61.135(e)(4), less than 18 m/sec (60 ft/sec).

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max} , as determined by the method specified in § 61.135(e)(5).

(6) Flares used to comply with this subpart shall be steam-assisted, air-assisted, or nonassisted.

(e) Owners or operators of control devices that are used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their design.

(f)(1) Closed-vent systems shall be designed for and operated with no

detectable emissions, as indicated by an instrument reading of less than 500 ppm above background and by visual inspections, as determined by the methods specified in § 61.135(c).

(2) Closed-vent systems shall be monitored to determine compliance with this section initially in accordance with § 61.05, annually, and at other times requested by the Administrator.

(3) Leaks, as indicated by an instrument reading greater than 500 ppm above background or by visual inspections, shall be repaired as soon as practicable, but not later than 15 calendar days after the leak is detected.

(4) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(g) Closed-vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 61.133 Alternative standards for valves in benzene service—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 61.137(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it must be repaired in accordance with § 61.132-11 (d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in benzene service within the coke by-product recovery plant shall be monitored within 1 week by the methods specified in § 61.135(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves in benzene service for which leaks are detected by the number of valves in benzene service within the coke by-product recovery plant.

(d) Owners or operators who elect to comply with this alternative standard shall not operate valves in benzene

service with a leak percentage greater than 2.0 percent.

(e) If an owner or operator decides to no longer comply with § 61.133-1, the owner or operator must notify the Administrator in writing that the work practice standard described in § 61.132-11 (a)-(e) will be followed.

§ 61.133-2 Alternative standards for valves in benzene service—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b) (2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 61.137(d).

(b)(1) An owner or operator shall comply initially with the requirements for valves, as described in § 61.132-11.

(2) After 2 consecutive quarterly leak detection periods with the percentage of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in benzene service.

(3) After 5 consecutive quarterly leak detection periods with the percentage of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in benzene service.

(4) If the percentage of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 61.137 but can again elect to use this section.

§ 61.134 Alternative means of emission limitation.

(a) Permission to use an alternative means of emission limitation under Section 112(e)(3) of the Clean Air Act shall be governed by the following procedures.

(b) For equipment, design, and operational requirements of this subpart:

(1) Each owner or operator applying for permission shall be responsible for collecting and verifying test data to demonstrate equivalence of a means of emission limitation.

(2) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) For sources subject to § 61.132-2 (except tar decanters), §§ 61.132-3, 61.132-4(e), and 61.132-5(c), the Administrator shall compare test data for the means of emission limitation to a benzene control efficiency of 98 percent. For tar decanters, the Administrator shall compare test data for the means of emission limitation to a benzene control efficiency of 95 percent.

(4) The Administrator may condition the permission on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) For work practices in this subpart:

(1) Each owner or operator applying for permission shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) For each source for which permission is requested, the emission reduction achieved by the required work practices shall be demonstrated for a minimum period of 12 months.

(3) For each source for which permission is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for permission shall commit in writing each source to work practices that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the permission on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practices of this subpart.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any means of emission limitation.

(e)(1) Manufacturers of equipment used to control equipment leaks of benzene may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of benzene achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will grant permission according to the provisions of paragraphs (b), (c), and (d) of this section.

§ 61.135 Test methods and procedures.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the test method and procedure requirements provided in this section.

(b) Monitoring, as required by §§ 61.132, 61.133, and 61.134, shall comply with the following requirements.

(1) Monitoring shall comply with 40 CFR Part 60, Appendix A, Reference Method 21.

(2) The detection instrument shall meet the performance criteria of Reference Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Reference Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible, as described in Reference Method 21.

(c) When equipment is tested for compliance with no detectable emissions, as required in §§ 61.132-2, 61.132-3, 61.132-4(b), 61.132-4(f), 61.132-5(c), 61.132-6(e), 61.132-7(f), 61.132-8, 61.132-11(f), and 61.132-14(f), the test shall comply with the following requirements:

(1) The requirements of paragraphs (b) (1)-(4) of this section shall apply.

(2) The background level shall be determined, as set forth in Reference Method 21.

(3) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible, as described in Reference Method 21.

(4) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d)(1) Each piece of equipment within a coke-by-product recovery plant is presumed to be in benzene service unless an owner or operator demonstrates that the piece of equipment is not in benzene service. For a piece of equipment to be considered not in benzene service, it must be determined that the percent benzene content can be reasonably expected never to exceed 10 percent by weight (for equipment other than exhausters), or 1 percent by weight for exhausters. For purposes of determining the percent benzene content of the process fluid that is contained in or contacts equipment, procedures that conform to the methods described in ASTM Method D-2267 (incorporated by reference as specified in § 61.18) shall be used.

(2)(i) An owner or operator may use engineering judgment rather than the procedures in paragraph (d)(1) of this section to demonstrate that the percent benzene content does not exceed 10 percent by weight for equipment other than exhausters, or 1 percent by weight for exhausters, provided that the engineering judgment demonstrates that the benzene content clearly does not exceed 10 percent by weight for equipment other than exhausters, or 1 percent by weight for exhausters. When an owner or operator and the Administrator do not agree on whether a piece of equipment is not in benzene service, however, the procedures in paragraph (d)(1) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in benzene service, the determination can be revised only after following the procedures in paragraph (d)(1) of this section.

(3) Samples used in determining the percent benzene content shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(e)(1) Reference Method 22 of 40 CFR Part 60 shall be used to determine the compliance of flares with the visible emission provisions of this subpart.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \left(\sum_{i=1}^n C_i H_i \right)$$

where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25° C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20° C.

K = Constant, 1.740×10^7 (1/ppm) (g mole/scm) (MJ/kcal), where standard temperature for (g mole/scm) is 20° C.

C_i = Concentration of sample component i in ppm, as measured by Reference Method 18 of Appendix A of 40 CFR Part 60 and ASTM D2594-67 (reapproved 1977) (incorporated by reference as specified in § 61.18).

H_i = Net heat of combustion of sample component i , kcal/g mole. The heats of combustion may be determined using ASTM D2382-76 (incorporated by reference as specified in § 61.18) if published values are not available or cannot be calculated.

(4) the actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Method 2, 2A, or 2C of 40 CFR Part 60, as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max} , for air-assisted flares shall be determined by the following equation:

$$V_{max} = 8.76 + 0.7034(H_T)$$

V_{max} = Maximum permitted velocity, m/sec.

8.76 = Constant.

0.7034 = Constant.

H_T = The net heating value as determined in

paragraph (e)(3) of this section.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 61.135 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator may comply with the recordkeeping requirements in one recordkeeping system if the system identifies each record by each source.

(b) The following information pertaining to the design requirements of control equipment installed to comply with §§ 61.132-2, 61.132-3, 61.132-4, and 61.132-5 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3)(i) For any control device used to comply with § 61.132-4, the recorded design specifications shall include any parameters that are necessary to determine proper operation and maintenance of the control device.

(ii) For a wash-oil scrubber, the design parameters include the wash-oil flow rate, the temperature of the gases existing the scrubber, and the pressure at the scrubber spray nozzle.

(c) The following information pertaining to process vessels subject to § 61.132-2, light-oil sumps subject to § 61.132-3, storage tanks subject to § 61.132-4(b) or § 61.132-4(f), or mixer-settlers used to comply with § 61.132-5(c) shall be recorded and maintained for 2 years following each semiannual inspection; each annual maintenance inspection, and any other inspections for system blockage:

(1) The date of the inspection and the name of the inspector.

(2) A brief description of each visible defect in the source or control equipment and the method and date of repair of the defect.

(3) The presence of a leak, as measured using the method described in 61.135(b). The record shall include the method and date of repair of the leak.

(4) A brief description of any system abnormalities found during the annual maintenance inspection, the repairs made, and the date of repairs.

(5) A brief description of any system blockage, the repairs made, and the date of repair.

(d) The following information pertaining to any control device used to comply with § 61.132-4 shall be recorded and kept for a least 2 years:

(1) The dates when the control device was not operating as designed.

(2) The dates and description of any maintenance or repair of the control device.

(3) Any parameters monitored to ensure that control devices are operated and maintained in conformance with their design.

(4) If a wash-oil scrubber is used to comply with § 61.132-4, the records of the wash-oil flow rate, the temperature of the gases exiting the scrubber, and the pressure at the spray nozzle.

(e) When each leak is detected as specified in § 61.132-6, 61.132-7, 61.132-11 and 61.132-12, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 61.132-11(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(f) When each leak is detected as specified in § 61.132-6, 61.132-7, 61.132-11, and 61.132-12, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) "Above 10,000" if the maximum instrument reading measured by the methods specified in 61.135(b) after each repair attempt is equal to or greater than 10,000 ppm.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdown that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(g) The following information pertaining to the design requirements for closed vent systems and control devices described in § 61.132-14 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 61.132-14(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed-vent systems and control devices required in § 61.132-6, 61.132-8, and 61.132-9, are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in § 61.132-6, 61.132-7, 61.132-8, and 61.132-9.

(h) The following information pertaining to all equipment subject to the requirements in §§ 61.132-6 to 61.132-14 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that the owner or operator elects to designate for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, under the provisions of §§ 61.132-6(e), 61.132-7(f), 61.132-8, or 61.132-11(f).

(ii) The designation of equipment as subject to the requirements of §§ 61.132-6(e), 61.132-7(f), 61.132-8, and 61.132-11(f) shall be signed by the owner or operator.

(3) A list of equipment identification number for pressure relief devices required to comply with § 61.132-8(a).

(4)(i) The dates of each compliance test as required in §§ 61.132-6(e), 61.132-7(f), 61.132-8, and 61.132-11(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(i) The following information pertaining to all valves subject to the requirements of 61.132-11 (g) and (h) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation of each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(j) The following information shall be recorded for valves complying with § 61.133-2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(k) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in § 61.132(d)(5) and 61.132-7(e)(2) and an explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(1) Information and data used to demonstrate that price of equipment is not in benzene service shall be recorded in a log that is kept in a readily accessible location.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7114)

§ 61.137 Reporting requirements.

(a)(1) An owner or operator of any source to which this subpart applies shall submit a statement in writing notifying the Administrator that the requirements of 61.132, 61.133, 61.135, 61.136, and 61-137 are being implemented.

(2) In the case of an existing source or a new source which has an initial startup date preceding the effective date, the statement is to be submitted within 90 days of the effective date, unless a waiver of compliance is granted under § 61.11, along with the information required under § 61.10. If a waiver of compliance is granted, the statement is to be submitted on a date scheduled by the Administrator.

(3) In the case of new sources that did not have an initial startup date preceding the effective date, the

statement shall be submitted with the application for approval of construction, as described under § 61.07.

(4) The statement is to contain the following information for each source:

(i) Type of source (for example, a light-oil sump, benzene storage tank, or pump).

(ii) For equipment in benzene service, equipment identification number and process unit identification.

(iii) For equipment in benzene service, percent by weight benzene in the fluid at the equipment.

(iv) For equipment in benzene service, process fluid state in the equipment (gas/vapor or liquid).

(v) Method of compliance with the standard (for example, "gas blanketing," "use of a tar-bottom final cooler," "monthly leak detection and repair," or "equipped with dual mechanical seals").

(b) A report shall be submitted to the Administrator semiannually starting 6 months after the initial report required in § 61.137(a), which includes the following information:

(1) For process vessels subject to § 61.132-2, light-oil sumps subject to § 61.132-3, storage tanks subject to § 61.132-4, or mixer-settlers used to comply with § 61.132-5(c);

(i) A brief description of any visible defect in the source or ductwork.

(ii) The number of leaks detected and repaired.

(iii) A brief description of any system abnormalities found during the annual maintenance inspection, the repairs made, and the date of repair; and

(iv) A brief description of any system blockages or malfunctions, the repairs made, and the date of repair.

(2) If a control device is used to comply with § 61.132-4(a), the date and time of any occurrence when the monitored parameters exceed or drop below the parameter levels determined in the design specifications.

(3) If a wash-oil scrubber is used to comply with § 61.132-4(a), the date and time of any occurrence when the wash-oil flow rate or the pressure at the scrubber spray nozzle drop below the parameter levels determined in the design specifications, or the temperature of the gases exiting the scrubber exceeds the design specification temperature.

(4) For equipment in benzene service:

(i) Process unit identification.

(ii) For each month during the semiannual reporting period:

(A) Number of valves for which leaks were detected as required in § 61.132-11(b) of § 61.133-2.

(B) Number of valves for which leaks were not repaired as required in § 61.132-11(d).

(C) Number of pumps for which leaks were detected as described in § 61.132-6(b) and (d)(6).

(D) Number of pumps for which leaks were not repaired as required in § 61.132-6(c) and (d)(6).

(E) Number of exhausters for which leaks were detected as described in § 61.132-7(f).

(F) Number of exhausters for which leaks were not repaired as required in § 61.132-7(g).

(5) The facts that explain any delay of repairs and, where appropriate, why a process unit shutdown was technically infeasible.

(6) Dates of process unit shutdowns that occurred within the semiannual reporting period.

(7) Revisions to items reported according to paragraph (a) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(8) The results of all performance tests to determine compliance with § 61.132-6(e), 61.132-7(f), 61.132-8(a), 61.132-11(f), 61.132-14(f), 61.133-1, and 61.133-2 conducted within the semiannual reporting period.

(9) A statement signed by the owner or operator stating whether all provisions of 40 CFR Part 61, Subpart L had been fulfilled during the semiannual reporting period.

(c) In the first report submitted as required in § 61.137(a), the report shall include a reporting schedule stating the months that semiannual reports shall be submitted. Subsequent reports shall be submitted according to that schedule unless a revised schedule has been submitted in a previous semiannual report.

(d) An owner or operator electing to comply with the provisions of § 61.133-1 or § 61.133-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

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