

PROCEEDINGS

Oil Spill Conference

Prevention,
Behavior,
Control,
Cleanup

20th Anniversary Conference



1989 Oil Spill Conference



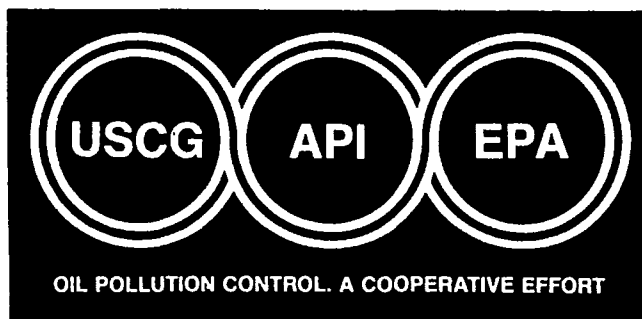
Proceedings

1989 Oil Spill Conference ***(Prevention, Behavior, Control, Cleanup)***

20th Anniversary Conference

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FOREWORD

The first Oil Spill Conference was held in New York in December 1969. It was jointly sponsored by the American Petroleum Institute and the Federal Water Pollution Control Administration (FWPCA), predecessor of the Environmental Protection Agency. That conference attracted an international audience of 1,100 to hear 41 technical papers, several of which dealt with the Santa Barbara oil spill which occurred in January of that year. The goals of the first conference were "to delineate the overall dimensions of the oil spills problem, explore the present state of the art of prevention and control of oil spills, and review the relevant research and development efforts of government and private industry, both here and abroad."

The 1989 Oil Spill Conference celebrates the 20th anniversary of that first conference. Although academic research is widely recognized as having contributed equally with government and industry research, the goals of the 1989 conference remain largely as stated in 1969. However, both the state of knowledge and overall spill preparedness are vastly different from what they were 20 years ago. The Oil Spill Conference has become the major forum for sharing this information, and the Conference Proceedings volumes are critical references for anyone working in the field.

The current sponsors—the U.S. Environmental Protection Agency, U.S. Coast Guard, and American Petroleum Institute—are proud of the part the Conference has played in the progress on all aspects of the oil spill problem over the past 20 years. We also recognize that our work is not yet complete. For example, spill cleanup methods that increase, rather than minimize, the environmental impacts of spills are still occasionally used in areas that contain sensitive habitats. We need to reach a consensus about those habitats for which ecological considerations are to be primary and, similarly, those where esthetic considerations will prevail. In addition, further work is needed to improve our response capability for inland spills.

With this meeting, the Conference will have recorded 20 years of international thought on oil spill issues. The sponsors look to future Conferences to build on this base, and take this opportunity to thank the authors whose papers comprise the eleven Proceedings volumes, as well as the members of the Conference panels and planning committees who have contributed generously to it.

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Panel Discussion:

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Section I

BULK STORAGE TANKS

Session 1-C—Bulk Storage Tanks I

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LIMITATIONS ON UNDERGROUND STORAGE TANK LEAK DETECTION SYSTEMS

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ABSTRACT: This paper discusses the limitations imposed on internal volumetric leak detection systems for underground gasoline storage tanks by uncertainty in the value of the thermal expansion coefficient for gasoline and uncertainties in measurements of the temperature of the gasoline. For leak detection or level sensing systems that are used to infer or measure volumetric leak rates, correction must be made to account for the expansion or contraction of the gasoline. An analysis is made of experimental determinations, in other work, of the density of samples of gasoline and calculated values of the thermal expansion coefficient. The data are divided according to three categories of gasoline: regular, unleaded, and premium. In each of these categories the estimate of the standard deviation of the thermal expansion coefficient is approximately 3 percent of the mean value. Examples are given of the magnitude of the apparent leak rate or error in leak rate due to uncertainties in the thermal expansion coefficient.

In order to correct for expansion or contraction of the gasoline, the mean temperature of the entire quantity of the gasoline must be known. An error in mean temperature will result in an apparent leak rate or an error in leak rate. Examples are given of the magnitude of the apparent leak rate or error in leak rate.

Releases from leaking underground storage tanks, particularly those containing petroleum products such as gasoline, can have a significant negative effect on the quality of groundwater resources.² Various volumetric leak detection systems for tanks have been developed and applied to the internal testing of underground storage tanks containing petroleum products.^{3,6,11} These systems convert a change in measured or inferred liquid level in the tank during an interval of time to leak rate in gallons per hour. The performance of the systems is influenced by a number of factors, one of the most important of which is the variation of the product's temperature.^{3,8,10,11} In the present paper, the expansion or contraction of gasoline with temperature and the consequent limitations imposed by uncertainties in the thermal expansion coefficient and in the mean temperature will be discussed.

The change in volume of a quantity of gasoline due to a change in temperature from t_1 to t_2 can be expressed as

$$V_2 - V_1 = V_1 \alpha (t_2 - t_1) \quad (1)$$

Where: V_1 and V_2 = gallons

t_1 and t_2 = degrees Fahrenheit (°F)

α = coefficient of thermal expansion in gal/gal/°F or in (°F)⁻¹

The value of the thermal expansion coefficient for gasoline depends on the composition of the gasoline and can vary from sample to sample of the same grade.⁹

A model tank system will be adopted to illustrate the effects of

uncertainties in the thermal expansion coefficient and in the mean temperature of gasoline on the performance of leak detection systems.

Thermal expansion coefficient

The model system is a tank of 10,000 gallons capacity for which the volume of gasoline contained is determined or inferred at a 1-hour interval, that is, two determinations are separated by 1 hour.

Thermal expansion coefficients, used here for illustration, are taken from a National Bureau of Standards report published in 1978.⁹ Data in the report were used by the Joint American Petroleum Institute/American Society for Testing and Materials Committee on Static Petroleum Measurement in the development of a collection of petroleum measurement tables.¹

For the purposes of the present paper, the values of α are separated according to three groups: regular gasoline, unleaded gasoline, and premium gasoline. The values of α for each group are listed in Tables 1, 2, and 3, in gal/gal/°C and gal/gal/°F. The minimum and maximum temperatures at which the measurements of density from which α was inferred are listed also. The mean value of α , the estimate of standard deviation (SD), and the relative SD (SD/mean α) have been calculated for each group and included in the tables. The mean values of α for the groups are: 0.000704 gal/gal/°F for regular gasoline; 0.000691 gal/gal/°F for unleaded gasoline; and 0.000695 gal/gal/°F for premium gasoline. The corresponding values of relative SD are 3.0 percent, 2.6 percent, and 3.2 percent.

Two items with particular bearing on leak detection systems are (1) the variation in α from sample to sample within a gasoline grade (the

Table 1. Thermal expansion coefficient for unleaded gasolines

α (gal/gal/°C)	α (gal/gal/°F)	$t_{\min}$ (°F)	$t_{\max}$ (°F)
0.0012307	0.00068372	40.5	85.1
0.0012232	0.00067956	40.5	85.8
0.0012070	0.00067056	40.5	85.8
0.0012176	0.00067644	40.5	85.8
0.0012646	0.00070256	49.8	86.9
0.0012738	0.00070767	49.6	86.4
0.0012283	0.00068239	40.5	77.4
0.0012771	0.00070950	40.5	77.4
0.0012388	0.00068822	39.7	69.1
0.0013107	0.00072817	39.4	67.6
0.0012176	0.00067644	39.9	87.1

Mean α = 0.001244 gal/gal/°C = 0.000691 gal/gal/°F. Estimate of standard deviation (SD) = 0.000032 gal/gal/°C = 0.000018 gal/gal/°F. SD/mean α = 0.026 = 2.6 percent.

1. F.E. Jones is an independent consultant.

Table 2. Thermal expansion coefficient for premium gasolines

α (gal/gal/°C)	α (gal/gal/°F)	t_{min} (°F)	t_{max} (°F)
0.0012227	0.00067928	54.1	89.8
0.0012051	0.00066950	49.5	79.5
0.0012774	0.00070967	40.3	95.2
0.0012140	0.00067444	40.3	95.2
0.0012269	0.00068161	49.6	86.0
0.0012268	0.00068156	39.7	86.2
0.0012776	0.00070978	49.6	76.6
0.0013060	0.00072556	39.4	86.0
0.0013066	0.00072589	39.4	86.0

Mean $\alpha = 0.001251$ gal/gal/°C = 0.000695 gal/gal/°F. Estimate of standard deviation (SD) = 0.000040 gal/gal/°C = 0.000022 gal/gal/°F. SD/mean $\alpha = 0.032 = 3.2$ percent.

SD is a measure of this variation), and (2) the magnitude of α and the consequent accuracy requirements for temperature measurement. As a matter of convenience, a value of α of 0.000697 gal/gal/°F and an SD of 0.000020 gal/gal/°F will be used for the calculations that follow.

Using the model 10,000-gallon tank and determinations of the volume of gasoline contained, at a 1-hour interval, we now calculate the apparent leak rate due to an uncertainty in α for several values of change in temperature during the 1-hour interval.

From equation 1 it follows that the uncertainty in volume, ΔV , due to an uncertainty in thermal coefficient of expansion, $\Delta\alpha$, is given by the equation

$$\Delta V = V (\Delta\alpha) (t_2 - t_1) \quad (2)$$

Where: $V = 10,000$ gallons
 $(\Delta\alpha) = 0.000020$ gal/gal/°F

With these assumptions and an interval of 1 hour between determinations, the corresponding apparent leak rates for values of $(t_2 - t_1)$ are listed in Table 4. Apparent leak rates are also listed for $(\Delta\alpha)$ of 3 SD. Table 4 shows that under the conditions stated above, if the mean temperature of the gasoline were to change by 0.083°F during the 1-hour interval between measurements, the 3-SD uncertainty would result in an apparent leak rate of 0.05 gal/h.

Temperature measurements

In order to correct for the expansion or contraction of the gasoline, the mean temperature of the entire quantity of gasoline must be known. An uncertainty or error in the measurement of the mean

Table 3. Thermal expansion coefficient for regular gasolines

α (gal/gal/°C)	α (gal/gal/°F)	t_{min} (°F)	t_{max} (°F)
0.0012632	0.00070178	49.5	78.3
0.0012342	0.00068567	39.0	94.6
0.0012500	0.00069444	40.5	76.5
0.0012365	0.00068694	40.1	86.0
0.0013321	0.00074006	49.8	86.9
0.0012837	0.00071317	49.6	86.0
0.0012958	0.00071989	49.6	68.4
0.0012561	0.00069783	40.5	77.4
0.0012521	0.00069561	39.7	77.4
0.0012384	0.00068800	39.7	95.4
0.0012104	0.00067244	39.7	86.2
0.0013401	0.00074450	40.6	76.6
0.0012700	0.00070556	40.6	76.6

Mean $\alpha = 0.001266$ gal/gal/°C = 0.000704 gal/gal/°F. Estimate of standard deviation (SD) = 0.000038 gal/gal/°C = 0.000021 gal/gal/°F. SD/mean $\alpha = 0.30 = 3.0$ percent.

Table 4. Apparent leak rates due to 1-SD and 3-SD uncertainties in thermal expansion coefficient for a 10,000-gallon capacity tank

Temperature change (°F)	Apparent leak rate, for 1 SD in α (gal/h)	Apparent leak rate, for 3 SD in α (gal/h)
0.01	0.002	0.006
0.05	0.01	0.03
0.083	0.017	0.050
0.1	0.02	0.06
0.17	0.034	0.10
0.25	0.050	0.15
0.5	0.1	0.3
1.0	0.2	0.6

temperature will result in an apparent leak rate. For the model tank of 10,000-gallon capacity and a value of thermal expansion coefficient of 0.000697 gal/gal/°F, apparent leak rates due to various values of uncertainty or error in the measurement of mean temperature are listed in Table 5. Since two measurements or determinations of mean temperature are made, one each at the beginning and end of the 1-hour interval, the uncertainty or error is multiplied by the square root of 2 to combine by root sum squares.

Density measurement by hydrometry

The direct measurement of the density of gasoline, using a hydrometer in an attempt to avoid uncertainty in the value of the thermal expansion coefficient, would not be effective since the uncertainty in hydrometer measurements is approximately 0.1 percent.⁴ Again, since two measurements would be made, one each at the beginning and end of the 1-hour interval, the uncertainty becomes 0.14 percent. For the 10,000-gallon model tank, this uncertainty corresponds to an apparent leak rate of 14 gal/h!

Discussion and summary

Claims have been made that many leak detection systems are capable of detecting leak rates as low as 0.05 gal/h, a recommended criterion suggested by the National Fire Protection Association, Inc.⁵ The uncertainties outlined in the present paper are limitations on the performance of leak detection systems that can mask or elevate leak rates.

The thermal expansion coefficients used for illustration are more than 10 years old. There is therefore a question whether values of current supplies of gasoline are significantly different from these values. The uncertainties calculated here correspond to a tank of 10,000 gallons capacity; uncertainties for smaller volumes would be proportionately smaller.

It is to be emphasized that the product temperature of interest is the mean temperature of the entire quantity of gasoline. The accuracy or precision of the temperature-sensing system is neither the limitation

Table 5. Apparent leak rates due to uncertainty or error in mean temperature, t_{mean} , for a 10,000-gallon capacity tank

Uncertainty or error in t_{mean} (°F)	Apparent leak rate (gal/h)
0.001	0.01
0.005	0.05
0.010	0.10
0.020	0.20
0.051	0.50
0.10	0.99
0.51	5.0



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nor the measure of the quality of the mean temperature determination. For example, thermistor thermometers are available that, given a restricted range of temperature and a 3-point calibration, can enable one to practice thermistor thermometry that is accurate within $\pm 0.005^{\circ}\text{C}$ ($\pm 0.009^{\circ}\text{F}$).⁷ However, determination of the mean temperature presents a sampling problem and a verification problem that dominate the measurement.

It has been demonstrated above that the direct measurement of the density of gasoline using a hydrometer is not appropriate since the uncertainty in hydrometer measurements is approximately 0.1 percent, with a corresponding uncertainty of 14 gallons in 10,000 gallons.

The apparent leak rates due to a 1-SD uncertainty in the thermal expansion coefficient, and due to uncertainties or errors in mean temperatures, are illustrated in Tables 4 and 5, respectively. For the 10,000-gallon quantity of gasoline, the National Fire Protection Association (NFPA) leak rate criterion, 0.05 gal/h, corresponds to a 1-SD uncertainty in thermal expansion coefficient for a temperature change between determinations of 0.25°F , to a 3-SD uncertainty for a temperature change of 0.083°F , and to an uncertainty or error in mean temperature of the entire quantity of gasoline of 0.005°F . Thus, these two sources of uncertainty or error impose very significant limitations on leak detection systems.

Conclusions

Since the density of the gasoline in the tank is the quantity that changes with the temperature of the gasoline, the severe limitations imposed on leak detection methods by the uncertainties discussed above could be avoided by a direct in-tank measurement of the density (not by hydrometer). It would then not be necessary to know the mean temperature very well or to know the thermal expansion coefficient of the gasoline.

A very precise and simple system for in-tank determination of the density of gasoline has been devised and will be the subject of a later paper.

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RISK ASSESSMENT: TOOLS FOR REDUCING LIABILITY FROM UNDERGROUND STORAGE TANKS

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ABSTRACT: Although regulations are being implemented at federal, state, and local levels, many major oil companies have decided to do even more than is required by law to prevent leaks from underground storage tanks (USTs). On the other hand, regulatory agencies directing cleanup of contaminated sites may demand restoration that goes beyond reasonable concerns for protection of public health and the environment. These cross-currents indicate that simply complying with applicable codes and regulations may not be an adequate strategy for cost-effectively reducing the risks of handling light refined products.

To control risks, it is important first to understand them. Risk assessment is useful before a leak occurs as well as after. Before the leak occurs, risk assessment requires estimates of the probability of release as well as the likely consequences (damages). Techniques are presented that can be useful to managers of a large number of tanks or insurance underwriters to assess risks and prioritize risk reduction measures. Ultimately, these procedures could be used to determine an appropriate budget for tank upgrade programs.

After a leak, and armed with detailed site assessment data, relatively precise estimates of toxic risks are possible. More realistic risk estimates are possible for refined petroleum product losses than are possible at many hazardous waste sites because of the relatively homogeneous and predictable properties of refined products. Field-verified predictive techniques that can be used to support defensible risk estimates are reviewed. Cost-effective strategies for collecting data required to support risk assessment and remediation of contaminated sites are stressed.

Risks can be mitigated to generally acceptable levels at some sites even if contamination substantially exceeds federal maximum contaminant levels (MCLs). At other sites, remediation to lower levels would be advisable.

Tank owners are confronted by two circumstances where risk assessment techniques can be of value in managing the amount of resources dedicated to environmental concern. First, there are decisions involving the prevention of leaks. Federal regulations recently promulgated under Subtitle I of the Resource Conservation and Recovery Act and an increasing number of state and local regulations dictate construction and retrofit standards designed to prevent leaks or spills or to contain what does occur. Regulatory requirements, although well intended, may not be suitable in every case. In locations where the potential for environmental liability is very great, such as in the presence of vulnerable drinking water supplies, tank managers have frequently decided to go beyond regulatory requirements and provide additional leak control and/or detection systems. Risk assessment techniques can be extremely useful in identifying cases where such measures are prudent.

Second, risk assessment can be valuable in providing a reasoned basis for setting cleanup standards when a leak has already occurred. Generally speaking, there is a wide variation in the cleanup standards

required by regulation and practice in various states. The standard that is set by regulatory agencies will dictate, to some extent, the available technologies and associated costs. In many situations, established risk assessment techniques can be used under existing regulations to arrive at reasonable and prudent standards that can be achieved economically while protecting human health and the environment.

To manage risks, it is important first to understand them. Risk assessment is useful before a loss occurs as well as after. Before a loss occurs, risk assessment requires estimates of this probability of release as well as the likely consequences (damages). After a leak, and armed with detailed site assessment data, relatively precise estimates of toxic risks are possible. This paper presents a variety of techniques that are available to support planning and risk management. For long-term planning and management, techniques will be presented that can be useful to managers of a large number of tanks, or insurance underwriters, to assess risks and prioritize risk reduction measures. Once a loss has occurred, cost-effective strategies for collecting data required to support remedial response planning will be stressed. Fate and transport and exposure assessment techniques will be presented.

As a preface to the paper, a general concept affecting risk assessment for losses of light refined petroleum products from underground storage tanks (USTs) must be introduced: More realistic and precise risk estimates are possible for this category of environmental risks than are possible for hazardous waste disposal sites. There are two primary reasons for this conclusion and one secondary reason:

- There is much less variability in the population of USTs than exists within the population of hazardous waste disposal sites. As a result, the physical conditions of the release are more homogeneous and thus more readily predictable. Robust assessment procedures can be developed that apply to conditions at most sites.
- The physical and chemical properties of the contaminants are also much more homogeneous than the wide variety of contaminants that may be present at hazardous waste sites. For example, all light refined products are lighter than water. In the case of unleaded gasoline, toxic risks can be assessed by focusing on a single contaminant—benzene. Although all refined products are not the same, and certainly any batch of gasoline is different from all other batches, nonetheless light refined products do share many similarities. These similarities permit the development of robust assessment procedures that apply to many releases.

Finally, the environmental contamination that results from the loss of a light refined product does not persist in the environment indefinitely. Tucker *et al.*²⁵ showed that under a wide range of environmental settings characteristic of the state of Florida, significant levels of contamination do not persist in groundwater for more than 12 years if free-floating product is recovered expeditiously. Although contamination may persist somewhat longer in areas with less favorable hydrogeologic and climatic conditions, contamination is not expected to persist over several human generations. At most sites, some combi-

nation of an engineered remedial action and natural restoration processes can lead to aquifer restoration within 5 to 20 years. This is well within the planning horizons of local land use and water management plans.

Furthermore, the natural attenuation processes also act most effectively at the leading edge of a contaminated groundwater plume, controlling and limiting its maximum areal extent. Considering the clearly limited extent of contamination, in both space and time, it is possible to anticipate how land and water within a potentially contaminated area would actually be used for the duration of a contamination incident. These factors reduce the uncertainty of assessing the risks associated with hydrocarbon losses. Some of the factors discussed have been taken into account by insurers who offer pollution liability coverage for USTs.¹⁸

Assessing the risks posed by a population of tanks

The topics to be addressed in this section should be of interest to two audiences:

- Managers or engineers charged with managing a large number of USTs to ensure environmental compliance and cost minimization. In cost minimization, we include remedial costs and liability due to product losses.
- Insurance underwriters evaluating whether to write environmental impairment liability (EIL) coverage to USTs, and establishing pricing strategies, including those that encourage risk reduction.

This paper will address the first audience, although many of the concepts are similar and apply to underwriters' concerns as well. The tank network manager typically must cope with resource limitations that dictate prioritization of risk reduction measures. A variety of options are available, including elimination of some tanks, though that option may hamper operational efficiency. The objective is to achieve the greatest risk reduction within cost restraints, that is, the most "bang for the buck." Let's begin with the most practical problem: how to do the most good with a fixed budget. To conclude this section, we will introduce additional techniques that can help define what the budget ought to be.

Risk is defined as the probability of an adverse outcome multiplied by the consequences if that outcome occurs. In this case, it is the probability of a product loss, P , times the damages, D , that may be expected from the loss:

$$\text{Risk} = P \times D \quad (1)$$

The probability of a release from a UST or a cluster of several USTs is principally affected by the system's design, construction materials, installation procedures, and age. For systems subject to corrosion, the physicochemical properties of the backfill material, including its moisture content, are also important. The variety of release modes and basic engineering factors that can prevent, mitigate, or cause releases are addressed in reports from the U.S. Environmental Protection Agency (EPA)^{12, 13, 14, 15, 16} and the American Petroleum Institute (API).^{2, 3} A few interesting facts are apparent from these sources.

Most unprotected steel tanks will fail by corrosion within 20 years of installation. A significant percentage, however, will not. Through fortuitous, and largely unpredictable, combinations of ideal fabrication and installation, approximately one-fourth of all bare steel tanks corrode uniformly rather than locally (for example, at a weld). Such tanks may maintain their integrity for much longer than 20 years. If a bare steel tank has not failed by corrosion in 20 years, it probably will not for a long time.

Another important finding from the cited sources is that a lot of product losses result by noncorrosive mechanisms. These are dominated by mechanical damage during or shortly after installation, overfill, and pump and plumbing joint failures. If one considers some of the less frequently encountered release mechanisms, such as vandalism and earthquakes, it should be recognized that the risk cannot be reduced to zero. There is an inherent risk in storage of petroleum products regardless of system design, installation, and operating procedures.

The aforementioned sources indicate that the probability of product loss can be reduced by retrofitting cathodic protection, or replac-

ing aging bare steel tanks; and by overfill protection. The probability of loss is also less if recent precision test results indicate that the system is tight. For the purpose of deciding how to spend a fixed budget, however, a quantitative estimate of the probability of a loss is not critical. It is sufficient to prioritize tanks with a large number of risk factors, such as older bare steel tanks without overfill protection. The age at which heightened concern is warranted (usually 10 to 15 years) depends on the corrosivity of backfill materials and whether the tank is installed below the water table.

It is impossible to go into greater detail in this paper on the risk factors affecting probability of a release, so let's turn to methods for estimating the damages if a leak were to occur. Damages are readily separated into two parts: remediation costs and liability to claims by other parties. Both can be affected by the nature and magnitude of the loss, the environmental setting and political jurisdiction of the site, and monitoring systems. The probability of substantial claims by third parties is also correlated with nearby water use, buildings, underground utilities, population density, and critical habitats.

Nature and magnitude of loss. It is impossible to predict in advance the type of loss that may occur. If it were possible, the tank manager would be able to prevent it. Some correlations with available information about the UST system may be anticipated, however.

Effective monitoring systems can reduce the loss. The losses that cause the most damage are slow leaks that go undetected for a long time.¹⁷ Catastrophic losses due to tank rupture by mechanical damage, overfills, and spills are responded to quickly. The spread of contamination over a large area can be, and usually is, prevented. Slow leaks can go undetected for months, without effective leak detection. In the past, they were often discovered only by their symptoms of taste and odor after spreading over a large area. These conditions increase remediation costs and the probability of substantial claims by other parties. An effective monitoring system that detects such slow leaks within hours, a week, or a month, will be responded to by emptying the UST system. The total volume lost would thus be reduced substantially. Automatic, continuously operating leak detection systems have the potential to virtually eliminate slow leak losses. Reliability and down-time of such systems need to be accounted for. Inventory reconciliation and/or monthly sampling of monitor wells may also be expected to substantially reduce the volume lost by slow leaks, which historically have lasted for several months before detection.

Overfill protection. Overfill protection can reduce the number of losses significantly, but has relatively less effect on risk reduction. Historically, overfills have been a relatively frequent cause of losses, but overfill losses have below-average volume.^{15, 16} Response to overfills is relatively rapid, which further reduces the damages from this type of loss.

Environmental setting. Critical factors are depth to water, whether an uppermost water table aquifer is used for potable supplies locally, the permeability of unsaturated soils above the water table, and the rate of groundwater movement in the uppermost aquifer. These factors can be addressed using DRASTIC, a screening tool used by EPA to evaluate the vulnerability of groundwater systems to superficial contamination.¹

Political setting. States and/or local jurisdictions that tend to enforce stringent cleanup standards can affect remedial costs. Jurisdictions that frequently impose fines or other penalties can be a significant source of claims by other parties.

Monitoring systems. The importance of effective monitoring in reducing risk was discussed under "Nature and Magnitude of Loss." Rapid response is critical to avoiding claims by other parties and can also significantly reduce response and remediation costs for slow leaks. Monitoring systems do not substantially reduce damages from catastrophic fast leaks, which are readily detected and responded to regardless of the monitoring system in use.

Receptors. The tank network manager should prioritize sites for risk reduction measures based on the potential to cause harm, including the following risk factors:

- Nearest downgradient potable well
- Number of potable wells within a specific distance
- Nearest residential, commercial, or institutional structure
- Number of people who occupy such structures within a specific distance
- Proximity to underground utilities (buried cables, sewers, water mains)



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- Proximity of critical habitats, such as protected wetlands, surface waters, endangered species habitats, and recreational fisheries.

To decide the most effective way to spend a fixed budget, relative ranking of sites according to risk is sufficient. The riskiest sites are highlighted for risk reduction actions. UST removal versus upgrade can be evaluated in the context of the criticality of the installation to meet operational objectives of the facility. Absolute risk estimates are required to determine the most appropriate response—to determine what the budget ought to be. Absolute risk estimates may also be needed to underwrite insurance. The former problem is solved by a classic optimization or total cost minimization technique once the absolute economic risk is estimated. This absolute risk can be calculated by Equation 1, with

$$P = P_n + P_c$$

Where: P_n = probability of loss by noncorrosive mechanisms
 P_c = probability of loss by corrosive failure.

Damages cover remedial costs and claims by others, including fines. A nominal estimate of remedial costs can be made considering the depth to groundwater, the transmissivity of the aquifer (affects pumping rate), the texture of soils in the unsaturated zone, and the political jurisdiction. The estimated remedial cost should be modified according to the anticipated response time based on the monitoring system in use at the facility.

Claims by others are expected to correlate with the number and severity of risk factors itemized earlier, and inversely with the response time of the monitoring system. This element of risk can be modified to consider such insurance-related issues as deductibles and maximum coverage per claim.

Through Equation 1, a variety of risk reduction measures can be evaluated: Tank removal, replacement and upgrade, overflow protection, and installation of more sophisticated monitoring equipment reduce the risk estimate. Costs of these options can be compared with the risk reduction (in dollars) to determine the lowest cost plus risk strategy.

Risk assessment after a loss

After a loss has occurred, risk assessment is an integral part of response planning. Risk assessment techniques similar to those applied for hazardous waste sites are generally appropriate.¹⁴ Florida and California, among other states, specifically identify risk assessment procedures as an integral element of the response planning process. The California Department of Health Services (CDHS) issued guidelines in 1986;¹⁰ Florida's regulations are codified in Florida Administrative Code Section 17-70. Selected topics pertinent to petroleum losses are discussed below.

Planning field data collection. California's site mitigation decision tree¹⁰ and the data quality objectives process under Superfund¹² are examples of the integration of risk assessment considerations into the field data collection planning process. The author recommends the process outlined in Figure 1 at each decision point regarding additional data collection. Extreme assumptions (best case and worst case) should be adopted to fill all data gaps. Two risk estimates should be made based on the extreme assumptions, an upper and lower bound. If the upper bound estimate represents a risk acceptable to all parties, then additional data collection is not required. A no-action alternative would be viable. If the lower bound risk is unacceptable, then remediation should proceed. If the upper and lower bounds span the acceptable risk range, this analysis would imply significant uncertainty regarding the risks posed by contamination at the site, and additional data would be necessary to reduce the uncertainty in the risk estimate.

The step in Figure 1 labeled "Determine additional data requirements" involves a variety of considerations that cannot be developed, in this paper. It is critical that additional data collection be designed to reduce the uncertainty in the risk estimate cost effectively.

Selection of indicator chemicals. One of the simplest features of risk assessment for subsurface losses of light refined products is the selection of indicator chemicals. Toxicity of unleaded gasoline is associated primarily with the benzene fraction²¹ and this simplifying concept has been applied to risk assessment by the Florida Petroleum Council¹⁷ and EPA.^{15,16} Tetraethyl lead and ethylene dibromide additives are

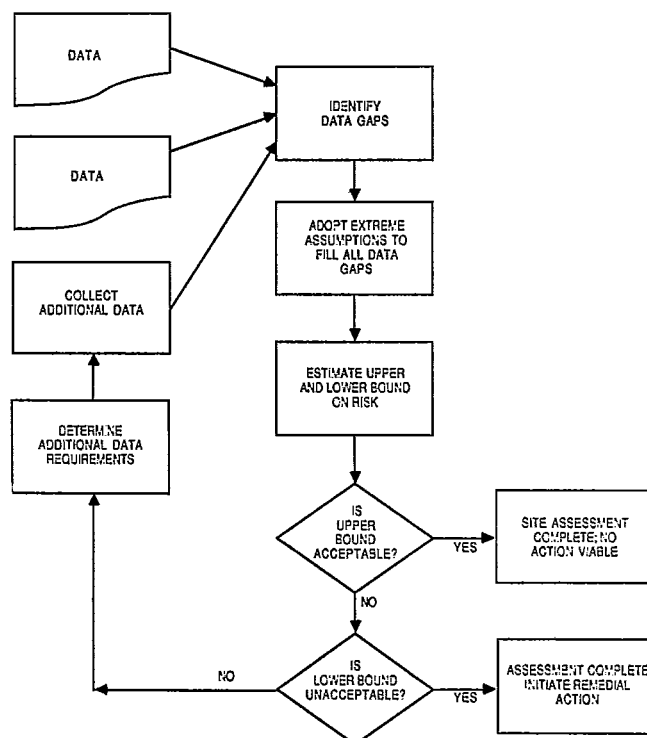


Figure 1. Data collection process flow chart

significant contributors to toxicity and risk for some gasolines. Other aromatics, including toluene and xylenes, can also contribute to taste and odor problems but are of relatively low toxicity when compared to benzene. Diesel fuels and light fuel oils generally contain polynuclear aromatic hydrocarbons (PNAs). The specific PNAs typically observed in significant concentrations in light refined products are two- and three-ring structures (such as naphthalene) usually considered to have lower toxicity than the heavier PNAs, which include benzo(a)pyrene. Nonetheless, these compounds are occasionally grouped and reported as total PNAs. When this approach is used, the lighter PNAs are usually attributed the same toxicity as benzo(a)pyrene, a procedure that probably overstates the risk.

Fate and transport assessment. The migration behavior of free product in the subsurface is quite complex and will not be described in detail here. If free product is encountered at a site, risks may be presumed to be unacceptable, and recovery of the product is usually warranted (Figure 1). Fate and transport assessment in support of risk assessment would generally focus on sites with residual contamination after free product has been recovered.

Residual hydrocarbons are petroleum products immobilized in soil/sediment pores by capillary action against the forces of gravity or hydraulic gradients. Theoretical prediction, or modeling, of the leaching, volatilization, biodegradation, and transport of the constituents of residual hydrocarbons is complicated and, for most purposes, can only be handled by computer simulation. There is a strong interaction between the unsaturated and saturated zones, since a major fraction of the residual hydrocarbons may be found near the fluctuating water table elevation. Recent research has focused on simulation of the biodegradation process because microbial action is apparently the dominant fate process ultimately restoring contaminated soils and groundwater.

Significant advances have been made recently in the development of computer models that address these complexities. Corapcioglu and Baehr¹¹ and Baehr and Corapcioglu⁵ presented a model for the fate of an eight-component mixture analogous to gasoline in the unsaturated zone. Their model rigorously evaluates leaching, volatilization, and biodegradation and their effects on contaminant migration.

water and weathering of the residual product. The model has not been validated and does not simulate fate in groundwater. Its extensive input and computational requirements qualify it as a research tool, unsuitable for routine site-specific application in its current state of development.

Borden and Bedient^{6,7} presented Bioplume II, an aquifer fate and transport model that emphasizes dissolved oxygen availability as the critical constraint on biodegradation. It simultaneously simulates dissolved hydrocarbons and oxygen in the aquifer, triggering rapid degradation at the boundaries of a plume where both constituents are optimal. Bioplume II has been field-validated at a site in Michigan. Bioplume II does not simulate the fate of residual hydrocarbons in the unsaturated zone. Its input requirements are generally consistent with data routinely available at contaminated sites, with the exception that aquifer dissolved oxygen is not routinely monitored.

Tucker *et al.*^{24,25} presented the Underground Leak Transport Assessment (ULTRA) model, a comprehensive model of the fate and transport of benzene released with petroleum hydrocarbon losses. It addresses unsaturated and saturated zones as a coupled system. Oxygen availability is addressed by imposing an upper bound on the biodegradation rate, but the oxygen distribution is not resolved spatially as in Bioplume II.

In summary, the ULTRA concept includes the following:

- Water flows from the land surface through soils to the aquifer.
- The source of benzene is associated with residual hydrocarbons in the unsaturated soil zone immediately above the water table.
- Infiltrating rainwater dissolves benzene from the residual hydrocarbons and carries it to the aquifer.
- Benzene may also be released to the aquifer if the water table rises into the contaminated zone.
- Benzene concentrations in the source area decrease with time as leaching carries benzene to the aquifer, and natural mitigation by volatilization and biodegradation takes place.
- Benzene released to the aquifer is transported with the flowing groundwater and diluted by dispersion processes.
- Contaminated groundwater may be pumped out of the aquifer to simulate groundwater restoration actions.
- Benzene may be biodegraded within the aquifer or volatilized from the water table.

ULTRA was validated against field data from two leak sites in Florida, as indicated by a comparison of predicted and observed groundwater concentrations at one of the sites, shown as Figure 2. Similar results were observed at the second site. Concentrations predicted by ULTRA are expected to be reliable to within a factor of 5. These applications illustrate that natural mitigation processes acting in the subsurface are more effective than groundwater pumping and treatment systems in reducing benzene concentrations in the subsurface. This is illustrated by Figure 3, which shows the fate of subsurface benzene at one of the two sites.

ULTRA is a powerful predictive tool in support of risk assessment of petroleum-contaminated sites, particularly since it has been field-verified, and its input requirements are consistent with data routinely available at contaminated sites.

Exposure assessment. Exposure to toxic contaminants in the ground is virtually negligible in most situations. Exposure to groundwater contaminants occurs principally after the water is extracted by a well and used domestically. One exception to this rule occurs when free product or groundwater containing volatile contaminants migrates under a residence or other structure. If the water table is fairly close to the surface, vapors can diffuse through the unsaturated zone and accumulate in the confined air of the building.

Jury *et al.*²⁰ presented the theory of molecular diffusion of vapors through soils. The flux, F (mg/m²/day) is given by:

$$F = \frac{n_a^{10/3} D_a C_a}{n^2 h}$$

Where: n_a = air-filled porosity of the soils

n = porosity of the soils

D_a = molecular diffusion coefficient of the contaminant in air (m²/day)

C_a = concentration in the air phase at equilibrium with the free product or contaminated groundwater (mg/m³)

h = depth to product or water (m)

If free product contains 2-percent benzene, the concentration in air

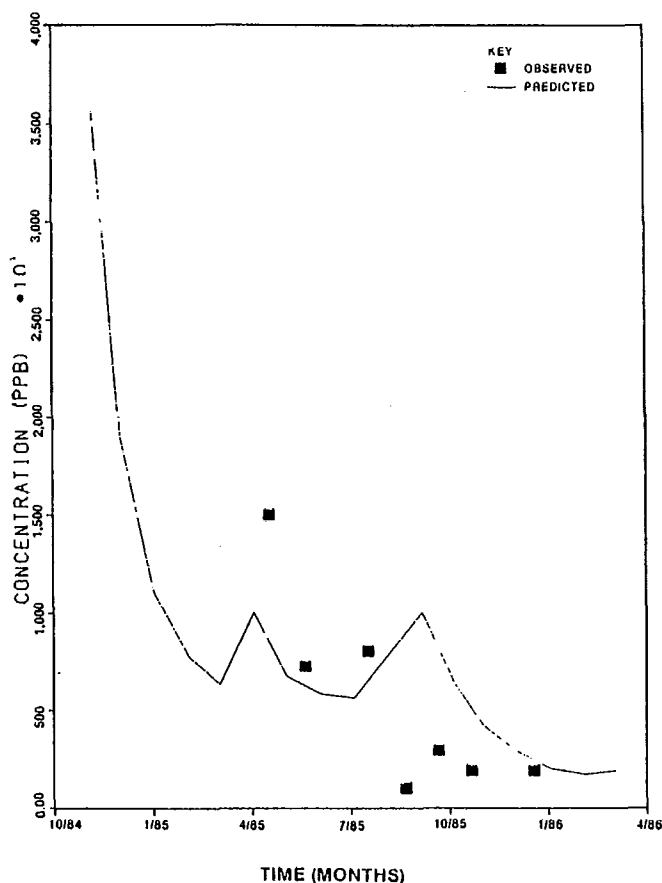
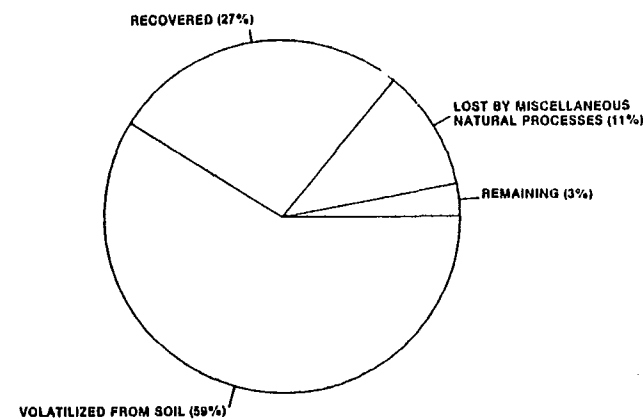


Figure 2. Comparison of predicted and observed concentration of benzene in the recovery well—Vero Beach site

at equilibrium is 2 percent of the saturation vapor density of benzene or 8,740 mg/m³. To evaluate vapor diffusion flux from contaminated groundwater, Henry's law applies, resulting in C_a (mg/m³) = 0.235 C_w (μg/L), D_a = 0.90 m²/day.^{24,25} Thus,

$$F = 7,850 \frac{n_a^{10/3}}{n^2 h}$$



NOTE: MISCELLANEOUS NATURAL PROCESSES INCLUDE BENZENE DEGRADATION AND VOLATILIZATION FROM THE AQUIFER, AND DISCHARGE TO SURFACE WATERS. THESE PROCESSES ARE ACCOUNTED FOR, BUT NOT SUMMARIZED IN MODEL OUTPUTS, IN THE CURRENT VERSION OF ULTRA.

Figure 3. Model-predicted fate of subsurface benzene during 17 months after free-product recovery—Vero Beach site

where free product containing 2 percent benzene is present; and

$$F = 0.212 \frac{n_a^{10/3} C_w}{n^2 h}$$

where free product is not present.

The steady-state concentration in the structure can be calculated by a simple ventilation model, that is

$$C_i = \frac{F}{Nh}$$

Where: C_i = concentration in indoor air (mg/m^3)
 N = number of air exchanges per day
 h = building height

Applying reasonable values for a detached one-story residence of $N = 20 \text{ day}^{-1}$ and $h = 3 \text{ m}$, then

$$C_i = \frac{F}{60}$$

Typical values of $(n_a^{10/3}/n^2)$ range from 5×10^{-5} for clay soils to 0.15 for a clean sand. Loams are intermediate and average 0.03.²³

Following EPA risk assessment guidelines, C_i should not exceed $0.0135 \text{ mg}/\text{m}^3$ (lifetime cancer risk of 10^{-4}). The risk level of 10^{-4} may be appropriate since the exposure is not expected to persist for 70 years. This concentration should be contrasted with the average indoor benzene concentration of $0.0258 \text{ mg}/\text{m}^3$ reported from 353 homes by Sample and Gilbert.²²

The results of calculations based on these formulae and data are presented in Table 1, which shows the maximum concentration of benzene in groundwater to avoid indoor air concentrations exceeding $0.0135 \text{ mg}/\text{m}^3$. Air diffusion through clay soils is so slow that even if there were floating product under the building, it would not result in unacceptable air concentrations. On the other hand, in loamy or sandy soils, unacceptable exposures could occur by contaminated groundwater transport under buildings, regardless of the source of potable water for the residents.

Assuming that contaminated groundwater is used domestically, a variety of exposure pathways are possible. Recent research indicates that inhalation exposures in the home may well exceed direct ingestion of tap water where volatile contaminants are concerned. Direct ingestion of unboiled tap water is a relatively small source of exposure for most people.⁴ The International Commission for Radiological Protection (ICRP)¹⁹ recommends assuming 0.1 to 0.2 L/day of direct tap water ingestion. In several studies discussed by Andelmann,⁴ intake of tap water by adults (including beverages such as coffee and tea) ranged from 0.96 to 1.3 L/day. A portion of this intake is associated with beverages prepared from boiled water, which tends to drive off volatiles such as benzene. It is clear that we do not ingest the amount of benzene contained in 2 L of water per day. There is good reason to believe, however, that we would inhale that much benzene from the release to indoor air of volatiles from the much larger volume of water used in a house every day. Results, such as those reported by Andelmann⁴ support an assumption that domestic use of water results in exposure to the volatile contaminants contained in 2 to 4 L of water per day. Most of the exposure is by inhalation. As a result, provision of bottled water for drinking and cooking does not substantially reduce exposure if contaminated water is still used for bathing and sanitary purposes in the home.

A final exposure pathway of interest is the use of well water to irrigate vegetable crops such as are commonly grown in back yard

gardens. Briggs, *et al.*^{8,9} presented a method for estimating plant uptake from irrigation water. Their results indicate that the concentration of benzene in plant tissues, on a wet weight basis (C_p , $\mu\text{g}/\text{kg}$), would be about equal to the concentration in irrigation water, given in $\mu\text{g}/\text{L}$. If back yard gardeners consume an average 0.1 kg of home-grown produce per day their exposure would be:

$$\text{Exposure } (\mu\text{g}/\text{day}) = 1 \frac{\text{L}}{\text{kg}} C_w \left(\frac{\mu\text{g}}{\text{L}} \right) 0.1 \frac{\text{kg}}{\text{day}} \\ = 0.1 C_w (\mu\text{g}/\text{L})$$

Based on the discussion of exposure to indoor water uses, at the Federal maximum contaminant level (MCL) of $5 \mu\text{g}/\text{L}$, people are exposed to about 10 to $20 \mu\text{g}$ of benzene per day. A similar exposure would occur if well water were used to irrigate the back yard vegetable garden and the concentration was approximately $100 \mu\text{g}/\text{L}$. If this exposure persisted for 15 years, the incremental individual cancer risk would be approximately 10^{-6} .

To summarize this discussion of exposure pathways, it was found that even where local groundwater is not used for domestic purposes, exposures to subsurface hydrocarbons can occur by volatilization from the water table or use of well water to irrigate vegetable gardens. Site-specific assessment would always be required to evaluate exposures. If a loss occurred far from any occupied buildings, groundwater contamination may pose negligible risk. In many populated areas with shallow water tables, however, groundwater contamination exceeding approximately $100 \mu\text{g}/\text{L}$ benzene could pose an unacceptable risk regardless of the source of tap water.

Conclusions

The applicability and utility of a wide range of risk assessment procedures to manage the risks posed by subsurface losses of light refined petroleum products have been illustrated. Anyone charged with the responsibility of managing UST facilities to avoid environmental liabilities should be aware of the variety of ways that risk assessment can support rational planning and decision-making.

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Table 1. Maximum benzene concentrations in groundwater to avoid unacceptable indoor air exposures ($\mu\text{g}/\text{L}$)

Depth to water (m)	Soil type		
	Clay	Loam	Sand
1	NA	130	25
3	NA	380	76
6	NA	760	150
10	NA	1,300	250

NA = Not applicable; even the presence of floating product could not cause unacceptable indoor air exposures.

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TECHNOLOGIES FOR THE REMOTE DETECTION OF HYDROCARBONS IN THE SUBSURFACE

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ABSTRACT: An increase in the frequency of hydrogeologic assessments in response to hydrocarbon losses from storage systems has prompted this research effort to evaluate economical and effective remote detection techniques. Two general technology groups were evaluated for their ability to detect the contaminant as well as their cost effectiveness. These technologies include soil gas and geophysical techniques. The soil gas techniques evaluated included active and passive procedures. The geophysical technologies which were evaluated on the basis of the same criteria included electromagnetic surveys, resistivity, and ground penetrating radar. This paper describes the interference factors associated with each technique and the relative costs of the technologies given the same set of assumptions.

A nationwide increase in assessment activity to delineate the horizontal and vertical extent of subsurface product losses from storage tanks and pipelines has prompted efforts to control escalating costs associated with these investigations. Over the past several years, reconnaissance techniques that preliminarily define the extent of hydrocarbon plumes have proven successful in reducing investigative costs by limiting the number of monitoring wells required. To develop an understanding of the relative effectiveness of these technologies, a research effort was funded by the American Petroleum Institute (API) to examine two families of promising technologies.

The first of these families is the soil gas technique which encompasses both active and passive soil gas technologies. The soil gas technique is dependent on the volatilization of hydrocarbon gases into the interstices of the soil in response to differential pressures and temperatures in the subsurface. The soil gas concentrations are relatively correlatable to the concentrations of contaminants present in the soil or ground water.

The second type of technology evaluated was geophysical techniques which include electromagnetic surveys, resistivity, and ground penetrating radar. These techniques rely upon the conductivity differential and the complex dielectric permittivity differential between the contaminant plume and the subsurface materials.

The objective of this study is to review and evaluate the available technologies and their associated costs. The results of a field verification program are currently being evaluated to compare the detection capabilities of the technologies examined with known hydrocarbon plumes.

Soil gas technology

The theory which describes the movement of volatile contaminants through the soil column indicates that volatile organic contaminants

present in the ground water and soil volatilize from these sources into overlying air-filled soil pores and migrate upward by molecular diffusion. Although contaminants can diffuse through either air or water-filled pores, molecular diffusion in air is a much more rapid process than aqueous diffusion.⁴ Therefore, volatile contaminants which partition readily to air will diffuse more quickly in dry soils than in saturated or nearly saturated soils. Contaminant movement from the ground water into the soil gas is a function of the concentration of volatiles in the ground water, their vapor pressures, and their partitioning coefficients. Technologies evaluated in this study which are dependent upon upward migration of volatile components into the interstices of the soil column include organic vapor analyzers (OVA), explosimeters, accumulator devices, capture bags/charcoal tubes, and photoionization detectors (PID).

The physicochemical basis for all soil gas techniques involves three fundamental concepts from the thermodynamics of partitioning phenomena. The primary assumptions are that the partial vapor pressure of a compound in the soil void volume is proportional to the concentration of the compound in the other phases present in the soil and that these phases are in approximate equilibrium with the vapor. There are three important phases and theoretical relationships that govern the soil gas equilibrium compositions. The free product phase is governed by Raoult's Law. Raoult's Law applies to ideal solutions at relatively high concentrations. The equilibrium between free product petroleum in soil and petroleum components present in the soil gas is approximately governed by Raoult's Law. For dissolved constituents in the ground water, the governing relationship is Henry's Law which states that the vapor concentration of a component over a dilute solution of that component is proportional to the concentration in the aqueous phase times a constant.

The equilibrium between the soil gas concentration of a compound and that compound adsorbed to soil particles is governed approximately by a linear relationship. The concentration of a petroleum constituent in the soil gas is proportional to its concentration in the organic carbon present in the soil. This partitioning is dependent upon the organic carbon content of the soil and a linear partitioning relationship between the adsorbed concentration and the vapor concentration. The constants for this relationship have not been well defined in the literature.

In summary, the soil gas measurement technique can be used to estimate the concentration of petroleum components present in the ground since the soil gas vapor concentration is proportional to the concentration of each component present in the soil and ground water. The governing relationships are approximately linear; however, the scale factors such as the partition coefficients between adsorbed species and soil gas concentrations are not well documented. As a result, soil gas measurements are more useful for estimating extent of contamination relative to uncontaminated areas than estimating absolute concentrations.

Interference factors

Environmental factors that inhibit uniform volatilization and volatilization rates also inhibit an instrument's ability to detect volatiles in the soil gases. However, some of these factors may be overcome and valuable data may still be obtained. Factors which affect data collection are:

- Geology (permeability/porosity variation)
- Temperature
- Depth of groundwater
- Moisture
- Presence of nonhydrocarbon contaminants

Geology. The geology of the study area is an important factor. More specifically, soil porosity and permeability determine the applicability of soil gas as a detection method since significant interstices must be present and accessible for the gases to migrate upward through the soil column. If vadose zone soil conditions in the vicinity of the collector are such that volatile hydrocarbons in the soil gases cannot reach the collector, then an erroneous reading could result. Thompson and Marrin¹⁸ state that "soils possessing air-filled porosities less than five percent may not yield an adequate sample volume."

A homogeneous soil column of sand is preferred for using soil gas techniques. In areas where the soils are inhomogeneous, the contaminant volatiles move through the soils unevenly and produce slightly variable data. If enough data are collected, concentration isopleths will smooth any anomalous high or low readings inside the plume area.

Temperature. The volatilization rate of the contaminants is a temperature-dependent phenomenon with higher volatilization rates occurring at higher temperatures. Therefore, the concentrations obtained using soil gas techniques will generally be higher at higher effective ground temperatures than at lower effective ground temperatures. Krauss et al.¹⁰ report that soil gas concentrations fluctuate at any given location throughout a 24-hour period, but that diurnal fluctuations in response to the warming and cooling of the soils during the day and evening are not evident. Soil temperatures do not vary significantly below 36 inches deep. The U.S. Department of Commerce reports a range of zero to one degree Fahrenheit (°F) between the minimum and maximum temperatures in soil at a depth of 40 inches in sandy, South Florida soils. Ducharme⁵ found no daily variation in soil temperature below six feet (ft) in the same geographic area.

Depth. The concentration of the soil gases tends to be greater near the area where free product is present, where contaminated soil is present, or where elevated concentrations of dissolved hydrocarbon constituents are present in the ground water. Thompson and Marrin¹⁸ report that petroleum hydrocarbons are best detected with probes that sample the soil gas near the top of the water table.

The depth of the contaminated zone in relation to each aquifer and aquitard is also an important factor. If the hydrogeologic system consists of multiple aquifers and aquitards, then the contaminated zone may be overlain by an uncontaminated aquifer or a dense confining layer inhibiting the detection of volatile hydrocarbons.¹⁹

In addition to the above depth considerations, a soil gas probe should not be installed at a shallow depth in order to minimize the introduction of ambient atmospheric air into the soil gas probe sample.

Moisture. The presence of a high moisture content in the soil may retard the ability to detect soil gas at the surface due to the lower diffusion rates of vapors in water-filled pores. For example, heavy rain may have the same effect as having the contaminants under an overlying aquifer or aquitard. Low soil moisture content to the point that vapors are vented to the atmosphere through a well defined network of cracks will tend to result in lower soil gas readings than will moderate soil moisture conditions. Krauss et al.¹⁰ indicate that moderate soil moisture content increases the soil gas response. Soil gas samples should be collected when the extreme conditions of heavy wet soils or dry cracked soils are absent.

Non-hydrocarbon contaminants. The presence of non-hydrocarbon contaminant plumes may mask hydrocarbon plumes in circumstances where total organic vapor detection instruments are used to screen a site.

Active soil gas collectors

Technologies that operate on the principle of detecting volatile contaminant vapors in the soil column fall into two classes: active collectors, and passive collectors. Active soil gas collectors are techniques that involve driving a hollow tube into the soil and then pumping the soil gases out of the soil for analysis. Active soil gas sampling techniques evaluated in this paper are: OVAs, capture bags, explosimeters, and PIDs. The OVAs, PIDs, and explosimeters provide real time data from each sample station.

Organic vapor analyzers. The OVA operates on the basic principle of a flame ionization detector which is sensitive to the presence of organic vapors. OVAs can be used in a survey mode or in a chromatographic mode. In the survey mode, an air sample is continuously delivered to a chamber containing a hydrogen flame. If the air contains an organic vapor, the molecules are ionized and a current proportional to the concentration of the organic vapor is carried between the detector electrodes. The response of the OVA to an organic contaminant is expressed relative to a standard since different organic contaminants will ionize to varying extents in the hydrogen flame.

The OVA operating as a chromatograph uses hydrogen gas as a carrier and the flame ionization detector as the sensor. A volume of the sample is injected through a chromatographic column appropriate to detect the contaminant of concern. As the sample passes through the column, its components interact with the materials in the column and the sample is separated into its components. As the components leave the column, they are detected by the flame ionization detector. The residence time of the sample or the time it takes for a sample to pass through the column and then be detected identifies the compound. The intensity of the reading is an indication of the concentration of the individual components.

Explosimeters. The explosimeter operates on the principle of the Wheatstone bridge. The soil gas sample is aspirated into a chamber in the explosimeter, and the sample is burned with heat from a platinum filament. Heat generated by the burned sample reduces the resistance of the filament, and the resistance change causes deflections on the meter. The explosimeter is calibrated to methane and indicates percent of the lower explosive limit referenced to methane. The explosimeter provides instantaneous data but cannot differentiate one flammable gas from another. The instrument is sensitive down to 1,000 ppm (0.1 percent) with an accuracy of 20 to 30 percent.

Photoionization detectors. The PID operates in a similar manner to the OVA in scanning mode. A PID uses an ultraviolet (UV) light source to ionize gaseous or vaporous compounds. The ions are collected on positive and negative electrodes, creating a current proportional to the concentration of the contaminant. PIDs draw air into the ionization chamber where certain molecules are ionized. Hydrocarbons and many hydrocarbon components are detectable with a PID. The PID detects total organic volatiles including petroleum derived hydrocarbons and does not differentiate between species. The detection limit is 0.5 ppm with a long-term relative standard deviation of 4.5 percent. A PID survey provides instantaneous data.

Capture bags. Capture bags are not a detector but a device for preserving the vapor sample for later analysis. Samples held in chemically inert Tedlar capture bags can be analyzed by any of the previously mentioned techniques or any of the standard laboratory methods. Gas-filled capture bags may lose their contents to molecular diffusion through the walls of the inflated bag. This process may work over a relatively short period of time. Polished stainless steel canisters can be used to hold gas samples for up to 30 days without compromising sample quality. The canisters can be cleaned and re-used. Laboratory methods used for soil gas assessments are gas chromatography (GC) with a PID. Methods which include the use of capture bags and analysis with GC have had good correlation of data with values measured in the ground water by direct analysis.¹⁵

Passive soil gas collectors

Passive soil gas collectors are sampling devices that contain a collection medium (adsorbent). The medium is containerized and buried

within one or two ft of the land surface and left for several days (usually 5 to 48 days, depending on site conditions). After the soil gas has had time to equilibrate between the adsorbent and the surrounding soils, the contaminants trapped on the medium in the containers are removed and analyzed. Passive soil gas sampling techniques that are being evaluated in this study are accumulator devices such as Curie point wires and industrial hygiene samplers.

Industrial hygiene devices. Industrial hygiene samplers consist of activated carbon filters placed in open inverted containers and buried one to three ft deep in the areas under evaluation. "Passive soil gas samplers operate on the principle of binary diffusion to induce a VOC mass flow onto the adsorbent," according to Kerfoot et al.⁷ The samplers are exposed for the appropriate length of time then removed, sealed, and sent to a laboratory for analysis.^{7,13} Occupational Safety and Health Administration (OSHA) research has shown that volatile organic compounds (VOCs) collected during sampling can be transported to a laboratory for analysis without loss when they are adsorbed to charcoal.⁷

Curie point wires. Curie point wire devices consist of activated carbon attached to a Curie point wire. Raising the wire to its Curie point results in a rapid desorption of the volatiles that have accumulated on the activated carbon after having been left in place from two to four weeks.

Once the soil gas samples are obtained, the samples are generally analyzed by gas chromatography or mass spectrometry. The samples can be analyzed in a standard laboratory or, in the case of gas chromatography, they may be analyzed in an on-site mobile laboratory. Non-mobile and mobile laboratory methods of analyzing for hydrocarbons are similar, using standard analytical methods and associated quality assurance/quality control (QA/QC) procedures. A Curie point heating device is used for desorption of the soil gas sample directly into a mass spectrometer. Kerfoot et al.⁷ describe analyzing for chloroform using the gas chromatograph method, and Bisque³ describes analyzing for hydrocarbons using the Curie point mass spectrometry method. The accuracy of this technique is found to be 95 percent for Curie point wires.

Geophysical survey technology

Instruments which operate on the basis of geophysical characteristics have been used for detection of contamination in the ground-water for less than 10 years.² Resistivity and electromagnetic (EM, also known as conductivity meter) surveys are geophysical techniques which operate on the principle of electrical conductance and may be applicable to the detection of hydrocarbon plumes. Ground penetrating radar (GPR) operates by detecting differences in electromagnetic permittivity.

The geophysical principles upon which the technologies are based create some limitations for the instruments.² The following section describes some of the limitations that are common to most geophysical instruments.

Geophysical interference factors

The instruments that operate on the principle of conductivity depend on the contaminant of concern having a significantly different conductivity than the surrounding native materials. Certain factors mask the differences between the contaminants and the surrounding materials, thereby inhibiting an instrument's ability to detect the presence of contaminants in the ground water and soils. In some cases, these factors may be compensated for and valuable data may be obtained. Factors which affect data collection for instruments based on conductance are:

- Manmade structures
- Geologic features
- Contaminant conductance
- Depth

Manmade structures. Manmade structures are a significant factor when performing a contamination survey based on conductivity.

Highly conductive linear features above and below ground, such as fences, telephone lines, power lines, buried pipes, cables, and reinforcing in buildings and sidewalks, as well as vehicles, can affect instrument readings.² Benson indicates that such interferences can sometimes be avoided by moving away from the troublesome object if the site configuration and plume size allow this.² Interfering objects sometimes also can be moved, or the data point simply disregarded.

Geology. Benson et al. also reported that interference due to the geological structure and stratigraphic complexity of the site may mask the contaminant plume.² If, for example, an air-filled void exists in the subsurface and the contaminant of concern has a low conductivity, then the void could be mistaken for the contaminant. If a site had a steep slope and the water table was within the vertical zone of investigation in only a portion of the site, then the water table could create some interference. Benson determined that some instruments do not work well in the presence of a shallow clay layer (due to its naturally high conductivity), a shallow water table, or, for other methods, a very low water table. Depth of signal penetration of the formations is site specific and depends on soil characteristics and the type of instrument used. For example, Benson found that increased clay content may enhance the performance of complex resistivity but degrades that of ground penetrating radar (GPR).

Contaminant conductance. The conductivity of the contaminant of concern is an important factor: if the conductivity of a formation or soil is significantly different than that of the contaminant, an instrument may be able to detect the presence of the plume.

Depth to contaminant. Geophysical instruments are limited in the depths to which they can effectively detect changes in the properties being measured. The signal can be masked by the factors discussed above. Because of that interference, contamination which occurs at depth is not detectable by some geophysical techniques. In all methods except GPR, the depth of investigation is determined by the instrument geometry. With GPR, depth of penetration is a function of both subsurface properties and the frequency of the signal generated. Some of the geophysical instruments can be operated in a sounding mode (in which the signal is sent deeper and deeper into the ground at the same location) and thereby collect data at various depths. Soundings by resistivity and conductivity devices are still subject to interference in either highly conductive or nonconductive materials.²

Geophysical instrumentation

Ground penetrating radar. GPR uses high frequency radio waves to obtain subsurface data. The waves radiate into the subsurface from a small antenna, and are then reflected back to the surface where they are picked up by a receiving antenna. Changes in the signal are recorded to provide a subsurface profile of shallow geologic conditions. Signal changes are caused by the different electrical properties of the materials that are encountered by the radio waves. The depth of penetration at a site is dependent on the electrical properties of subsurface materials at each site. For example, clay or salt water aquifers severely limit the depth of penetration. Average penetration is less than 10 meters.^{2,19}

GPR is a rapid reconnaissance method which can provide a high resolution view of the subsurface and/or the contaminant plume.² Olhoeft¹⁴ reported that GPR can detect water-insoluble organics floating on top of the water table at sites where interference factors are small.

Electromagnetics. An electromagnetic survey is conducted using a terrain conductivity meter, commonly referred to as an electromagnetometer (EM). An EM operates as follows: "A transmitter coil induces a current loop into the subsurface. The magnitude of this current loop is directly proportional to the terrain conductivity in the area of the loop. The current loop in turn generates a magnetic field which is proportional to the amount of current within that particular loop. The magnetic field is detected by the receiver portion of the instrument which yields an output voltage that is linearly related to the terrain conductivity. By changing the intraloop spacing, different depths can be surveyed."¹⁷

Table 1. Cost comparisons for nonintrusive hydrocarbon detection techniques

Methods	Instruments	Field days per method	Mobilization	Field effort	Per diem	Sample shipping	Sample analysis	Equipment rental	Total cost	Data turn around time
Soil gas active	PID	1	\$100.00	\$350.00	\$70.00	\$0.00	\$0.00	\$58.00	\$578.00	Minutes
—	OVA (total)	1	\$100.00	\$350.00	\$70.00	\$0.00	\$0.00	\$58.00	\$578.00	Minutes
—	OVA (GC) ₁	2	\$100.00	\$700.00	\$140.00	\$0.00	\$0.00	\$49.00	\$989.00	Hours
—	Explosimeter	1	\$100.00	\$350.00	\$70.00	\$0.00	\$0.00	\$19.00	\$539.00	Minutes
—	Capture bag GC or GCMS ₂	1	\$100.00	\$350.00	\$70.00	\$60.00	\$1,250.00	\$15.00	\$1,845.00	~30 days
—	Capture bag GC or GCMS	1	\$100.00	\$350.00	\$70.00	\$0.00	\$1,500.00	\$15.00	\$2,035.00	Hours
Soil gas passive	Curie Point wire	2	\$200.00	\$700.00	\$140.00	\$60.00	\$1,875.00	\$0.00	\$2,975.00	~60 days
—	Industrial hygiene samplers	2	\$200.00	\$700.00	\$140.00	\$60.00	\$1,250.00	\$0.00	\$2,350.00	~60 days
—	Industrial hygiene samplers ₂	2	\$200.00	\$700.00	\$140.00	\$0.00	\$1,500.00	\$0.00	\$2,540.00	~50 days
Geophysical surveys	GPR ₃	1	\$100.00	\$350.00	\$70.00	\$0.00	\$0.00	\$2,150.00	\$2,670.00	Hours to days
—	EM	1	\$100.00	\$350.00	\$70.00	\$0.00	\$0.00	\$35.00	\$555.00	Minutes
—	Resistivity	1	\$100.00	\$350.00	\$70.00	\$0.00	\$0.00	\$10.00	\$530.00	Hours

1. OVA being used as a GC will take one day more to complete the same number of samples as using the OVA as a scanning device.

2. The analysis was performed in an on-site mobile laboratory.

3. Cost of a GPR survey may vary from \$2,500 to \$10,000 depending on site size and the amount of data reduction.

Saunders and Germeroth determined that an EM detector can detect floating hydrocarbon product with thicknesses greater than 0.1 ft, and that at some sites a relationship could be developed between the EM data set and the thickness of floating hydrocarbon.¹⁷ EM data can be used to detect conductive contaminant plumes which may contain dissolved hydrocarbon compounds; Glaccum et al. did not address floating hydrocarbons as a part of this study.⁶

Resistivity. Electrical resistivity is a direct earth contact technique in which current probes make physical connection with the soils.¹⁹ In paved areas, holes must be drilled or broken through to the soil. Electrical current flows into the ground through one set of electrodes, and the potential drop is measured across a second set of electrodes. Various geometries of electrode arrays are used to achieve specific objectives, such as greater depth of penetration and detection of lateral variations. Resistivity data can be gained on the depth of the water table, aquitards, and bedrock.¹⁹ Olhoeft indicates that the electrical conductivity of a formation is determined primarily by the volume of water in the formation and the electrical conductivity of the materials filling the pores.¹⁴

Electrical resistivity requires more time than EM or GPR to cover an area,^{2,14} but provides more accurate and detailed profiles of the subsurface with depth. Contaminant plumes can be detected by electrical resistivity if the electrical resistance of the plume is different than that of the surrounding formation.^{1,14} Andres and Canace indicated that electrical resistivity is able to detect hydrocarbon plumes when the contaminants have lowered the resistivity of the ground water below background and that the detectability of the hydrocarbon plume depends on the relative thickness of the plume.¹

Method cost assessment

In an assessment of the relative cost of employing one instrument and technology versus another, it is important to identify the assumptions and not misrepresent or inadvertently penalize any instrument. The assumptions to be used for this analysis have been chosen to fix many variables that generally occur in an actual field effort. The assumptions are as follows.

- The site is 50 miles from the origination point of the equipment, costing \$100.00 in mobilization fees per trip.

- The field effort takes one day for geophysical methods, one day for soil gas (capture bag), and two days for passive soil gas techniques. One day is budgeted for deployment and one day for retrieval of passive devices, allowing a three week accumulation period.
- Fifteen soil gas samples can be analyzed in one day using GC in a mobile lab.
- One day of field effort will cover a 100 × 100 foot square area.
- Per diem will equal \$70.00 per day.
- Shipping, for methods that require off-site chemistry labs, will cost \$60.00 per day.
- The average rate for the personnel on site is \$35.00 per hour or \$350.00 per day.
- Each day is estimated to be a 10-hour day.

Table 1 summarizes the cost of performing reconnaissance surveys for the techniques discussed in this paper, given the assumptions presented above.

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FACILITY-SPECIFIC CONTINGENCY PLANNING UNDER THE OIL SPCC REGULATIONS

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ABSTRACT: Under the U.S. Environmental Protection Agency's (EPA) Oil Spill Prevention, Control, and Countermeasures (SPCC) program, facilities must complete an oil spill prevention and control plan. If a facility is unable to complete a control plan, a contingency plan must be completed in accordance with the SPCC regulations. A recent EPA SPCC Program Task Force found these regulations to be inadequate in several areas, including mandatory facility-specific contingency planning.

Contingency planning should be conducted in a three-phase approach: completing risk assessment of the specific facility, determining the manner in which identified risks will be managed, and preparing for the execution of contingency plans during a spill emergency. A risk assessment of a facility subject to the SPCC regulations consists of hazard identification, vulnerability and exposure analysis, and event and fault tree analysis. Risk management consists of various components, including the identification of personnel, equipment, emergency procedures, and waste disposal options. The execution of a contingency plan depends upon accessibility of the appropriate equipment, which may include trucks, boats, communication systems, booms, and dispersants. Contingency plans for facilities covered under the SPCC regulations should provide specific information related to notification procedures, spill response, and mitigation.

On May 13, 1988, the Environmental Protection Agency's (EPA's) Spill Prevention, Control, and Countermeasures (SPCC) Task Force published a report that identified several areas of deficiency in the SPCC regulations. Among these areas, and of particular concern, was the lack of site-specific spill contingency planning. This void can be attributed to several factors, one of which is the lack of clear regulatory guidelines. Although contingency planning is, in fact, referenced in Volume 40 of the Code of Federal Regulations (CFR), Part 109, this regulation does not provide an explicit set of guidelines for facility owners. The SPCC regulations in 40 CFR Part 112, in a similar manner, do not specifically address contingency planning and instead focus upon prevention measures. It is generally believed that proper contingency planning would have averted the serious consequences of the Ashland oil spill in Floreffe, Pennsylvania, on January 5, 1988. As in the case of the Ashland Oil Co. spill, a little effort devoted to planning would go a long way toward mitigation in the future.

Proper contingency planning is straightforward, and should be completed by facility owners. To complete an effective contingency plan, three steps must be taken: conducting a risk assessment of the

specific facility, determining the manner in which risks will be managed, and preparing for the execution of the contingency plan during a spill emergency.

Risk assessment at a facility refers to engineering and management decisions regarding the facility's design capabilities. A risk assessment for a facility covered under the SPCC regulations should consist of the following three components: hazard identification, vulnerability and exposure analysis, and event and fault tree analysis. Identifying potential hazards will provide specific information on situations that may be harmful. This information usually describes storage areas, product volumes, and the nature of hazards. The vulnerability analysis identifies areas of immediate concern following a spill event and provides an estimate of the area most likely to be affected. Considerable attention must be paid to population centers, wetlands, and areas that may be inhabited by endangered species. Finally, an event and fault tree analysis will identify potential spill scenarios. This type of information, which is usually based on prior spills at the facility, can be used to estimate possible spill sizes, pathways, and causes of spills at other facilities.

Once a risk assessment has been completed, the manner in which the risk will be managed needs to be determined—that is, a contingency plan must be developed to outline methods for mitigating damage from an oil spill. Contingency planning involves the elimination or minimization of the risks identified during the risk analysis, and related preparedness actions.

The third component of risk assessment is the most critical phase. Once a contingency plan has been completed, equipment or other resources identified in the contingency plan must be purchased or otherwise provided. A contingency plan that is ignored or only partially fulfilled will be of no use in an emergency situation. A contingency plan should be capable of being followed during an emergency; it is only a plan until an emergency occurs, and then it becomes a method of action. Therefore, adherence to the contingency plan during an emergency is of utmost importance.

Risk assessment

Hazard identification. In order to identify a hazard, certain criteria must be analyzed. The total amount of storage capacity at the facility, in both holding and retention ponds for each storage tank and at each transfer point, must be determined in order to understand the maximum spill potential.

An understanding of the kind of oil being stored, as well as the location and types of tanks being used, is also necessary. Preliminary analyses of the oil types should be conducted to aid spill responders in cleanup efforts. Although the properties of products vary widely, different oils have common, basic features that permit categorizing (see Table 1). By categorizing oils, an evaluation of potential environmental effects and a determination of mitigation actions can be estimated. The following four categories are used for efficient decision-making related to spill response activities:

- Category 1: Light, volatile oils
- Category 2: Non-adhering oils
- Category 3: Heavy, adhering oils
- Category 4: Non-fluid oils

It is important to acknowledge the dynamic nature of these oil categories. Many oils are able to undergo extensive property changes during the period of an emergency, while others may not be affected by exposure to similar conditions.

Category 1: Light, volatile oils. The first category of oils includes diesel oils and many light crude oils. These materials can be flammable at the outset of a spill, but this threat can be diminished with exposure to the environment and under certain spill conditions. Category 1 oils are distinguished by high fluidity, clarity, rapid spreading rates, strong odors, and high evaporation rates. They tend to remain surface-bound and can be removed by flushing with water.

The lighter members of this category tend to evaporate rapidly. Heavier members will evaporate but will often leave some form of residue that may fall into a different category. Their tendency to penetrate porous surfaces is high, and they may contaminate substrata. When fresh, volatile oils can be toxic and can form unstable emulsions.

Category 2: Non-adhering oils. The second category of oils includes medium to heavy paraffin-base oils and is distinguishable by its waxy, oily, non-adhering nature. Although these types of oils adhere to vegetation, they are generally easily removed by flushing. Their tendency to penetrate permeable substrates is variable, and increases as the temperature rises. The toxicity concerns related to these oils vary in relation to the atmospheric conditions. When exposed to cool climates, they tend to become solid and fall into category 4. Characteristic of this category are fluids and emulsified oils.

Category 3: Heavy, adhering oils. The third category of oils typically includes residual fuel oils and heavier asphaltic and mixed-base crude

oils. They are generally viscous, sticky or tarry, and brownish-black in color. Plants and animals may be smothered by these heavy, viscous products. Many category 3 oils have a specific gravity near or exceeding that of water and tend to sink. These types of oils may weather quickly and become category 4 oils.

Category 4: Non-fluid oils. The fourth category of oils includes residual oils, heavy crude oils, and some high-paraffin crude oils. Weathered oils that are solid or non-fluid at spill temperatures may also be included under category 4. In solid form, these oils are essentially non-toxic. When subjected to high temperatures for protracted periods of time, they tend to melt or liquefy, thus contaminating a larger area.

Vulnerability and exposure analysis. It is important for both the facility owner and emergency response personnel to understand which areas are particularly vulnerable to an oil spill. This understanding requires a knowledge of the types of areas that are particularly affected by oil spills. In addition, information regarding the local geography and the use of downstream water must be gathered.

A facility owner should be aware of local water use and the placement of water intake controls in rivers or aquifers that are used for drinking water. The fouling of wetlands of any kind must also be avoided. Oil in such areas is certain to affect water supplies, fish and wildlife breeding grounds, and endangered species habitats.

Event and fault tree analysis. Perhaps the most critical aspect of oil spill contingency planning is the establishment of spill scenarios. Before scenarios can be constructed, the possible sources of pollution must be identified. A detailed drawing of the facility layout and design will facilitate the identification of spill sources and probable spill pathways. The facility description should include the company name and address, and a description of the type of operation being conducted. A detailed survey analysis of the facility boundaries, along with a detailed listing of storage areas and capacities, will also aid in identifying potential spill sources and pathways.

To further define potential spill sources, the facility's storage and transfer equipment must be examined for leaks or other problems. Weak links in the storage system, such as corroding tanks or tanks made from steel not in accordance with API 6540 version VII, need to be considered as possible spill sources. Weak links in the transfer operation, such as uncapped pipes or pipes that pass through a dike, should also be considered as sources of potential spills.

Risk assessment conclusions. By using the information gathered

Table 1. Four categories of oil and their properties

Categories	Definitions	Types of oil	Analytical properties	Physical chemical properties
1	Light volatile oils	Distillate fuel and most light crude oils	Highly fluid; usually transparent, but can be opaque; strong odor; rapid spreading; can be rinsed from plant sample by simple agitation	May be flammable; high rate of evaporative loss of volatile components; assumed to be highly toxic to marine or aquatic biota when fresh; tend to form unstable emulsions; may penetrate substrates
2	Non-adhering oils	Medium to heavy paraffin-base refined and crude oils	Moderate to high viscosity; waxy or oily feel; can be rinsed from surfaces by low-pressure water flushing	Generally removable from surfaces; penetration of substrates variable; toxicity variable; includes water in oil emulsions
3	Heavy sticky oils	Residual fuel oils; medium to heavy asphaltic and mixed-base crudes	Typically opaque brown or black; sticky or tarry; viscous; cannot be rinsed from plant sample by agitation	High viscosity; hard to remove from surfaces; tends to form stable emulsions; high specific gravity and potential for sinking after weathering; low substrate penetration; low toxicity (biological effects due primarily to smothering); will interfere with many types of recovery equipment
4	Non-fluid oils (at ambient temperature)	Residual and heavy crude oils (all types)	Tarry or waxy lumps	Non-spreading; cannot be recovered from water surfaces using most conventional cleanup equipment; cannot be pumped without preheating or slurring; initially relatively non-toxic; may melt and flow when stranded in sun

through hazard identification, vulnerability and exposure analysis, and event and fault tree analysis, a facility owner or operator will be able to assess the potential harm caused by a spill at the facility. Ways in which to mitigate, or even eliminate, a facility's potential for harm may also be identified.

Risk management

With the knowledge gained from the first step of risk assessment, the facility owner or operator can create a contingency plan, which consists of countermeasures to be taken if a spill becomes unmanageable. Contingency plans should identify a spill response coordinator, company and contracted resources, and the methods to use resources most effectively. Much of the information required for the completion of a contingency plan can be derived from the associated risk assessment.

When a facility-specific contingency plan is prepared, several different procedures and classes of equipment can be considered for use during the removal phase of an oil spill; however, it is extremely important to choose the right tools for the job. The type of oil involved, as well as the nature of the spill conditions, must be identified before any removal actions can be undertaken. More often than not, the availability of required resources is the greatest difficulty encountered during the initiation of a spill response. It is important to establish a spill contractor and equipment inventory list, with special consideration being given to the abilities of a spill contractor and the availability of equipment. To facilitate decision-making procedures, the establishment of some form of decision matrix can be useful. This matrix should provide decision-makers with the ability to identify the particular contractor who is properly equipped to respond quickly to a spill.

Most facilities use company personnel for response to an oil spill; however, occasionally more experienced personnel are required. One of the major disadvantages to the use of company personnel, who are primarily assigned duties related to company operations, for cleanup procedures is the lack of extensive spill training. Without the help of well-trained experts, additional complications may arise during spill removal.

Planned response use and implementation. Proper employment of spill resources can be achieved through the use of a pre-deployment policy. For example, appropriate boom placement on a waterway can prevent extensive cleanup operations. The determination of locations and placements of booms, which should provide possible off-site migration patterns and access points, can be determined by examining the facility schematic. It is important to understand the limitations of spill equipment; the improper deployment of personnel and equipment can be a costly mistake. The ability to employ equipment is often subject to available access points. The identification of access points is extremely important, and permission to use selected roads must be obtained in advance. Extensive communications prior to, during, and following a spill response are imperative. The use of radio and telephone communication can reduce the incidence of costly mistakes. The failure to communicate continually in an informative manner is by far the most critical factor in spill response activities.

Spill containment is another facet of proper contingency planning. Once oil has been discharged into the environment, a variety of techniques to contain the spill may be employed. Decisions must be made with respect to the use of dispersants, absorbents, skimmers, vacuum trucks, and the nature of waste disposal. All of these techniques require extensive planning before containment plans can be carried out; some of these methods require permission from federal, state, and local authorities. To better illustrate facility policies regarding spill containment, a schematic with specific placement of equipment should be prepared.

Waste disposal options. Although waste disposal practices vary from area to area, some of the most common practices are reclamation, incineration, biodegradation, and land farming. These options must be selected in accordance with state and local contingency plans. The decision to dispose of waste should never be made hastily, as this can prove to be costly. The locations of potential disposal sites near a facility or spill site should be identified and cataloged for future reference. When a disposal option has been selected, primary consideration should be given to procedures for carrying it out. Each of the

various methods of waste disposal have distinct advantages and disadvantages. For example, in order to incinerate oily waste, qualified personnel must be present in the event that a fire becomes uncontrollable. This method of waste disposal is extremely efficient for oil-soaked branches and brush that cannot be salvaged.

Disposal planning can provide field response personnel the knowledge necessary to mitigate a spill incident effectively. Upon completion of a spill response, an assessment of the contingency plan should be considered. The success of future spill responses can be judged by the improvements made to the existing contingency plan.

Execution of the contingency plan

A contingency plan should define response equipment that is available or must be purchased, as well as the procedures necessary to use the equipment. The facility owner or operator must follow the plan set forth in the contingency plan. The following items are examples of information and equipment that commonly need to be in place or purchased, as required by a contingency plan:

- Contractor listing
- Manpower listing
- Heavy equipment
- Transportation
- Vacuum trucks
- Boats
- Communications
- Booms
- Skimmers
- Absorbents
- Dispersants
- Disposal options

If these preparations are completed, the facility is likely to have an excellent contingency plan and to be well prepared for responding to an oil spill.

When a spill is discovered, the responsible party must initiate actions that will mitigate the spill event. These actions usually follow rigid requirements that are set forth in the facility's spill contingency plan. These requirements involve specific procedures related to notification, spill response, and mitigation.

Once a spill response has been determined to be necessary, certain types of data are required for an appropriate response action. Information regarding the spill and the affected, or potentially affected, area should be collected. Although most of this information should be available as a result of contingency planning, variable data (such as meteorological conditions) that are available only at the time of the incident should be collected to determine the most effective response. The checklist provided in the Appendix, which is a general synopsis of the spill data, will aid in selecting protection or cleanup methods. Time, location, and the volume of the spill, as well as the characteristics of the oil, will be used in determining the extent of the spill. Meteorological, wildlife, and water body data, which is extremely important to the success of spill response efforts, can be collected through various information channels, including the National Weather Bureau, topographical maps, and aerial reconnaissance. Once this information is gathered, the responders can act effectively.

Summary

All spill incidents cannot be predicted. Contingency planning provides the basis for functional responses during emergency situations. Understanding this philosophy will enable planners to predict possible spill scenarios with improved accuracy.

Appendix

Spill Data

Source: _____
Time: _____
Date: _____



Documents

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Volume of discharge: _____

Size and location of slick: _____

Direction of slick: _____

- Type of oil:
1. Light volatile oils
 2. Non-adhering oils
 3. Heavy, adhering oils
 4. Non-fluids oils

Meteorological Data

Air temperature: _____

Wind speed: _____

Precipitation: _____

Visibility: _____

Hydrological Data: _____

Additional Data: _____

A COMPARISON OF REGULATIONS RELATED TO THE OIL SPCC PROGRAM

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ABSTRACT: Several federal agencies regulate selected aspects of the production, refining, transportation, and storage of petroleum and petroleum products. Based on analyses of such programs, the U.S. Environmental Protection Agency (EPA) may propose modifications to the Oil Spill Prevention, Control, and Countermeasures (SPCC) program. These proposed changes would be likely to result in improved consistency with other government and industry standards.

Regulatory changes may occur in two extensive and significant areas: adoption of specific and widely recognized industry and regulatory tank standards, and mandatory contingency planning at all facilities covered by the SPCC regulations. Relevant industrial, trade association, and technical standards generated by the American Petroleum Institute, the Underwriters Laboratories, Inc., the National Fire Protection Association, the American National Standards Institute, and the National Association of Corrosion Engineers have been reviewed for applicability to the SPCC regulations. Areas of concern include materials specifications, welding requirements, pressure testing prior to service, overpressure and vacuum relief requirements, design specifications, hydrostatic testing requirements, and siting specifications.

Related federal statutes and regulations include the Resource Conservation and Recovery Act, U.S. Coast Guard regulations, the Occupational Safety and Health Act, Office of Pipeline Safety regulations, Minerals Management Service regulations, and Underground Storage Tank regulations. Regulatory references to tank and ancillary equipment integrity, tank and ancillary equipment standards, containment, inspections and testing, leak prevention and detection, and contingency planning could be adopted in the revised SPCC regulations.

The U.S. Environmental Protection Agency (EPA) Spill Prevention, Control, and Countermeasures (SPCC) program regulates nontransportation-related facilities that may reasonably be expected to discharge oil into or upon the navigable water of the United States or its adjoining shorelines, and that have oil storage capacities of more than 660 gallons in a single tank or collectively 1,320 gallons or more

Table 1. Storage tank codes and standards of industry and private concerns

Key areas/questions covered by code or standard	Piping code	Pressure vessel code	Storage tank codes and standards												
			ANSI B31.3	ASME Section VIII	API 650	API 620	API series 12				API inspection guide	UL 58	UL 142	NFPA 30	ANSI B96.1
							12B	12D	12P	12R1					
Organization ₁	I	I	I	I	I	I	I	I	I	I	P	P	I	I	
Material specifications/ requirements	X	X	X	X	X	X	X	X			X	X		X	
Welding specifications/ requirements	X	X	X	X		X								X	
Preservice pressure testing requirements	X	X	X	X		X	X				X	X	X	X	
Overpressure/vacuum relief requirements	X	X	X	X	X	X	X	X			X	X	X	X	
Basic sizing rules	X	X	X	X	X	X	X				X	X		X	
Siting requirements	X		X	X				X					X	X	
Leak detection guidance										X			X		
In-service inspection requirements										X					
Return to service inspection/ test requirements										X			X		

1. P = private, I = industry

Source: C-E Environmental, Inc. Analysis

aboveground, or 42,000 gallons or more underground. The SPCC program, which was established in 1973 to set minimum standards for certain aspects of facility design, operation, and procedures, regulates more than 650,000 facilities.

Several other federal agencies regulate selected aspects of the production, refining, transportation, and storage of petroleum and petroleum products. Industry standards used throughout the private sector are often adopted or incorporated by reference in the regulatory or standards-setting language of such programs. As a result of accidental oil discharges that have occurred during recent years, EPA is reviewing related federal programs, as well as industry guidelines, to identify components that would strengthen the current SPCC program. Regulatory changes may occur in two significant areas: adoption of specific industry and regulatory standards, and mandatory contingency planning at all facilities covered by SPCC regulations. Provisions on the applicability of the SPCC regulations are likely to remain unchanged.

Industry and regulatory tank standards

Industry standards. EPA SPCC regulations do not now require adherence to specific standards with respect to aboveground storage tanks for petroleum products. Many standards, however, are commonly and voluntarily followed by SPCC-regulated facilities and should be considered in good spill prevention programs. These standards include those issued by the American Society of Mechanical Engineers (ASME), American Petroleum Institute (API), Underwriters Laboratories, Inc. (UL), National Fire Protection Association (NFPA), American National Standards Institute (ANSI), and National Association of Corrosion Engineers (NACE). Two sets of standards issued by these organizations have emerged as major guidance resources for oil facilities: API 650, which describes specifications for aboveground storage tanks; and NFPA 30, which describes procedures for handling ignitable liquid wastes.

Revisions to the SPCC regulations may require compliance with applicable industrial and scientific codes and standards presently in existence. In addition to tank structures, standards could be applied to all piping, valves, fittings, and auxiliary equipment. Relevant standards address materials specifications, welding requirements, pressure testing prior to service, overpressure and vacuum relief requirements, design specifications with respect to sizing, and siting specifications. Table 1 presents the various codes and standards that are related to these areas of concern.

Specifications and requirements for construction materials in tank systems are provided in nearly all industrial standards, including ANSI B31.3, ANSI B96.1, ASME section VIII, API 650, API 620, API series 12, UL 58, and UL 142. With respect to welding specifications, ANSI B31.3, ANSI B96.1, ASME section VIII, API 650, API 620, and API Series 12 apply. Preservice pressure testing requirements for tank systems are specified by the same codes outlined for welding specifications, as well as those set forth by NFPA 30, UL 58, and UL 142. All industrial standards covered in this review, with the exception of the API inspection guide, outline specific requirements for overpressure and vacuum relief.

Basic sizing rules are specified by the majority of these standards; however, siting requirements are found in fewer—ANSI B31.3, API 650, API 620, API 12R1, NFPA 30, and ANSI B96.1. Only the API inspection guide and NFPA 30 provide leak detection guidance and test requirements for systems that are being returned to service. Finally, and unfortunately, only the API inspection guide requires in-service inspections.

Regulatory standards. Six federal programs may be compared to the EPA SPCC program. Some are issued from within the EPA, while others are managed by other federal organizations. These programs are the Resource Conservation and Recovery Act (RCRA) as enforced by EPA, U.S. Coast Guard (USCG) regulations, the Occupational Safety and Health Act (OSHA), the U.S. Department of Transportation's Office of Pipeline Safety (OPS) regulations, the U.S. Department of the Interior's Minerals Management Service (MMS) regulations, and Underground Storage Tank (UST) regulations as enforced by EPA. Various standards outlined in these regulations are critical to good spill prevention programs, and could be adopted or incorporated by reference in the SPCC regulations in the

future. Such standards address tank and ancillary equipment integrity, tank and ancillary equipment standards, containment, inspections and testing, and leak prevention and detection. The SPCC regulations, as outlined in 40 Code of Federal Regulations (CFR) Parts 109, 110, 112, 113, and 114, are currently presented as recommendations; however, revisions to these regulations could include mandatory compliance.

The six programs under review were examined by applications to the SPCC program. Under RCRA, facilities that generate, treat, store, or dispose of hazardous wastes, as defined in 40 CFR 261.3, are subject to compliance. USCG regulates facilities capable of transferring oil in bulk to or from any vessel with a capacity of 250 or more barrels of oil, as outlined in 33 CFR Part 154, and the transfer of oil on navigable waters to, from, or within vessels with capacities of 250 or more barrels of oil, as outlined in 33 CFR Part 156. Under 29 CFR 1910.106, the Occupational Safety and Health Administration regulates occupational settings where flammable and combustible liquids are present. Pipeline facilities and the transportation of hazardous liquids by pipeline in interstate and foreign commerce are regulated under OPS in 49 CFR Part 195. MMS is authorized to regulate all operations conducted under a lease issued or maintained at a facility on the outer continental shelf. UST, the last program reviewed, regulates any single tank, or combination of tanks, that are positioned 10 percent or more beneath the earth's surface.

Operation approvals or permits are required by four of these programs. Under RCRA, an EPA identification number must first be obtained. An operating permit, which usually involves a lengthy and extremely detailed application process, must then be obtained before operations are allowed to begin. If ownership of a permitted facility is transferred, a notification of RCRA requirements must be provided to the new owner by the previous owner. USCG requires a letter of intent to be submitted 60 days prior to commencement of facility operations. Along with the letter of intent, an operations manual must be submitted for review and approval by the Coast Guard. Following approval, a letter of adequacy must be received from the Coast Guard before operation startup. Noncompliance with 33 CFR Part 156 can result in immediate suspension of operations by the Coast Guard. MMS requires an exploration plan, or a development and production plan, to be submitted to MMS prior to operations, in addition to an environmental report. As for USCG, noncompliance with MMS regulations can result in an immediate suspension of operations. Last, the UST program requires a notification of tank installation or use to be submitted to the Office of Underground Storage Tanks (OUST).

A review of related federal regulations regarding the integrity of tank and ancillary equipment indicates that RCRA requires certification (which must accompany a RCRA permit application) by a professional engineer (PE), to document design standards, tank age, corrosion protection, leak testing results, and cathodic protection. API and NACE standards are recommended for use as guidelines. USCG issues specific requirements for hose assemblies, burst pressure, loading arms, closure, monitoring devices, and small discharge containment; ANSI B16.5, B16.24, B31.3 and B31.3a are recommended as guidelines. OSHA requires tanks to be spaced 3 to 20 feet apart, and that proper venting and fire resistant supports be installed. API 620 and 2000, the ASME Boiler and Pressure Code, ANSI 31, and UL standards are suggested by OSHA as guidelines. The Office of Pipeline Safety outlines specific minimum requirements for the design and construction of pipes, valves, and pumps, and specifically requires certain API, ASME, MMS, ANSI, and American Society for Testing Materials (ASTM) standards to be followed. The use of "best available and safest technologies" is loosely recommended by MMS. The sixth federal program under review, the UST regulations, specifies proper installation and design practices, corrosion protection, filling practices, repair limitations, closure requirements, leak detection, reporting requirements, and corrective action. UST also recommends that a national consensus of codes of practice be followed, including NFPA, ANSI, ASME, and API.

Three of these programs contain specific provisions for containment. RCRA requires secondary containment with appropriate material composition, adequate sizing to accommodate 100 percent of each tank's capacity, adequate base support, and a base that is sloped. According to OSHA, dikes must also be able to contain 100 percent of each tank's capacity. In addition, dike walls must average less than 6 feet in height, and earthen dikes must be more than 3 feet in width.

Table 2. Related federal regulations

	Resource Conservation and Recovery Act	Coast Guard	Occupational Safety and Health Act	Office of Pipeline Safety	Minerals Management Service	Office of Underground Storage Tanks
Applicability	Facilities that generate, treat, store, or dispose of hazardous wastes as defined in 40 CFR 261.3	Facilities capable of transferring oil in bulk to or from any vessel with a capacity of 250 or more barrels of oil as outlined in 33 CFR 154	Occupational settings where flammable and combustible liquids are present as outlined in 29 CFR 1910.106	Pipeline facilities and the transportation of hazardous liquids by pipeline in interstate and foreign commerce as outlined in 49 CFR 195	All operations conducted under a lease issued or maintained at a facility on the outer continental shelf	Any one or combination of tanks, including attached underground pipes, 10 percent or more beneath the surface (certain small tanks, residential systems and surface impoundments excluded)
Approval requirements and permits	EPA identification number RCRA operating permit Facility transfer of ownership requires notification of RCRA requirements to new owner by previous owner	Transfer of oil on navigable waters to, from, or within vessels with 250 or more barrels of oil as outlined in 33 CFR 156 Letter of intent submitted 60 days prior to operations			Exploration plan or development and production plan submitted prior to operations	Notification of tank existence or installation is required
Tank and ancillary equipment integrity	Certified by PE to include design standards, tank age, corrosion protection, leak test results, and cathodic protection Certification of integrity submitted with RCRA permit application Interim status facilities must keep certification on file	Operations manual, submitted with the letter of intent, to be reviewed and approved by USCG Letter of adequacy issued by USCG prior to operations Noncompliance of 33 CFR 156 can result in immediate suspension of operations			Environmental report submitted prior to operations Noncompliance can result in immediate suspension of operations Study program conducted by lessee, if requested during suspension	
Tank and ancillary equipment standards	API and NACE recommended as guidelines	Requirements for hose assemblies, burst pressure, loading arms, closure, monitoring devices, and small discharge containment	Tanks spaced at least 3-20 feet apart Venting Fire resistant supports	Specific minimum requirements for design, construction of pipes, valves and pumps 12-inch underground pipe clearance	Use of "best available and safest technologies"	Proper installation and design practices, corrosion protection, filling practices, repair limitations, closure requirements, leak detection, reporting requirements, corrective action
Containment	Secondary containment with proper composition material, adequate size to contain 100% tank capacity, base support, and sloped base Optional secondary devices such as liners, vaults, and double-walled tanks, recommended	ANSI B16.5, B16.24, B31.3 and B31.3a recommended as guidelines	API 620 and 2000, ASME Boiler and Pressure Code, or UL standards, suggested ANSI 831 recommended for piping Dikes must be able to contain 100% tank capacity Dike walls must average less than 6 feet in height Earthen dikes more than 3 feet in height must be 2 feet in width at top	API, ASME, MMS, ANSI, and ASTM standards cited and incorporated in regulations	Curbs, gutters, drip pans, and drains installed in deck areas to collect all contaminants not authorized for discharge Artificial islands, such as on the Alaskan North Slope, must have an impervious berm	National consensus codes of practice (NFPA, ANSI, ASME, API)
Inspections and testing	Inspection schedule submitted with RCRA permit application Facility inspections conducted weekly Tank system inspections conducted daily Testing of emergency equipment Annual inspection of cathodic prevention	Declaration of inspection completed prior to oil transfer Facility inspections performed annually Hydrostatic testing of hosing required	One-time testing (including hydrostatic) for strength and tightness ASME, API, or UL compliance must be marked on tank prior to use Periodic OSHA inspections	Pipes must be tested during construction Cathodic protection must be tested by test leads Required hydrostatic testing Annual facility pipeline system inspections Biennial inspection of valves	Annual onsite facility inspection Periodic onsite inspections without prior notice Monitoring of environmental impacts Corrosion testing of wells Operators must self-inspect facilities daily	Inspection on installation can be conducted Postinstallation integrity test Internal inspections, where feasible Various kinds of testing can be done
Leak prevention and detection	Secondary containment leak detection certified by PE in RCRA permit application Interim status facilities must keep certification on file	Hydrostatic testing of hoses		Each component of a pipeline system must be provided with corrosion protection	Use of blowout preventers Frequent pressure testing of well casing	Corrosion protection Soil gas monitoring Water table monitoring In-tank monitoring Interception well monitoring

Source: C-E Environmental, Inc. Analysis

and 2 feet in width at the top. MMS requires that curbs, gutters, drip pans, and drains shall be installed in deck areas to collect all contaminants not authorized for discharge. Artificial islands, such as on the Alaskan North Slope, must possess an impervious berm to comply with MMS regulations.

Although all of the federal programs reviewed include specifications for the inspection and testing of tanks and ancillary equipment, the SPCC regulations are currently among the least mandatory.

RCRA requires that an inspection schedule, which must accompany every RCRA permit application, must include inspections of every facility on a weekly basis, and tank system inspections on a daily

basis. Also included at the time of RCRA permit application is a PE certification that secondary containment leak detection capabilities has been installed. Testing of emergency equipment must be performed on a regular basis. Cathodic corrosion prevention equipment must also be inspected annually. USCG requires a declaration of inspection to be completed prior to all oil transfers, a facility inspection to be performed annually, and hydrostatic testing of hosing to be conducted, as required.

In contrast, OSHA requires only a one-time testing (including hydrostatic testing) for strength and tightness; however, compliance with ASME, API, or UL standards must be marked on all tanks prior



Documents

Document Sharing Hub

Table 3. Contingency planning

	Resource Conservation and Recovery Act	Coast Guard	Occupational Safety and Health Act	Office of Pipeline Safety	Minerals Management Services	Office of Underground Storage Tanks
Contingency planning	24-hour surveillance system, or controlled access barrier, required Danger signs posted	Emergency procedures delineated in the facility Operations Manual (33 CFR 154.310)		Maintain liaison with local authorities. Maintain current maps of system Pipeline markers as required	Environmental protection equipment Safety equipment Contingency plans for drill site and associated onshore activities	
Emergency preparedness	Contingency plan filed with state and local authorities, and submitted with RCRA permit application Assigned spill coordinators	Shutdown procedures Appropriate communication system Adequate lighting	Emergency venting Earthquake resistancy Elimination or control of ignition sources Preparedness plans incorporated in facility safety and health program Sign use	Manual for emergency procedures to be reviewed annually Shutdown procedures Post-accident review of employee activities	"Lessee shall take all steps necessary to prevent accidents and fires"	

Source: C-E Environmental, Inc. Analysis

to use. OSHA is authorized, at its discretion, to inspect facilities periodically.

OPS regulations include several elements of good inspection and testing procedures: testing of pipes during construction, testing of cathodic protection by use of test leads, hydrostatic testing, biennial inspections of valves, corrosion protection throughout pipeline systems, and annual inspections of facility pipeline systems. In MMS regulations, the use of blowout preventers is specified, as is the practice of frequently pressure-testing well casings.

Last, under UST regulations, corrosion protection and monitoring of soil gas levels, water tables, tanks, and interception wells are required.

A summary of this comparison of regulatory standards is presented in Table 2.

Contingency planning

A comparison of contingency planning activities required by the federal programs under review indicates that contingency planning is becoming an increasingly significant component of hazardous materials management plans. As the current SPCC regulations stand, contingency planning for facilities is required only in the event that a complete SPCC plan is not feasible; however, EPA has the authority to mandate site-specific contingency planning at all SPCC-regulated facilities.

The RCRA contingency planning provisions are extremely relevant to the SPCC program, and could serve as a model for modifications to the SPCC requirements. RCRA regulations require a written contingency plan to be submitted at the time of RCRA permit application, filed with state and local authorities, and maintained on site. The contingency plan must provide a list of persons qualified to act as emergency coordinators, a list of emergency equipment at the facility, and a facility evacuation plan. In addition, a 24-hour surveillance system must be operative at all RCRA-regulated facilities; in lieu of a surveillance system, access to a facility must be completely controlled by use of barriers. Danger signs are also required to be posted at appropriate locations throughout the facility property.

Spill prevention programs should coordinate closely with Title III of the Superfund Amendments and Reauthorization Act (SARA). Under Title III, owners and operators of regulated facilities are required to develop methods for determining the occurrence of a release and the area or population likely to be affected in the event of a release, and must identify transport routes for extremely hazardous substances. Title III also requires preparation of release response procedures, a list of community and facility emergency coordinators, notification procedures, evacuation plans, and emergency response and medical personnel training.

The National Oil and Hazardous Substances Pollution Contingency Plan (NCP), as authorized by the Comprehensive Environmental Response, Compensation, and Liability Act and the Clean Water Act, outlines guidelines for preparing federal, regional, and local contingency plans. Although NCP guidelines do not apply to facilities, relevant procedures for use in site-specific contingency planning may be adapted by industry and other federal programs.

Facilities subject to the USCG regulations must submit an operations manual, prior to commencement of operations, that establishes emergency shutdown procedures. The "person in charge" of an oil transfer operation must be fully qualified to serve as an emergency coordinator, and must ensure that adequate communication and lighting systems are maintained.

The Occupational Safety and Health Act standards for contingency planning require that an emergency action plan be prepared in writing and maintained on site at all facilities with ten or more employees. The emergency plan must describe escape procedures, medical services, designated persons in charge, and emergency training programs. OSHA provisions for a fire prevention plan require a listing of all fire hazards present at a facility, a description of handling and storage procedures, a description of fire protection equipment, identification of potential ignition sources, the names of persons in charge of fire equipment, housekeeping procedures, and maintenance of fire prevention equipment. OSHA hazard communication programs require container labeling, where appropriate, and other types of warnings and material safety data sheets.

The Office of Pipeline Safety requires that facilities establish close liaison with local facilities. At each site, a current map of pipeline systems must be maintained, and pipeline markers are to be installed, where appropriate. A manual for emergency procedures, which is to be reviewed annually in house, must include emergency shutdown procedures.

MMS requires the use of environmental protection equipment and safety equipment. Although regulations issued through MMS loosely require lessees of oil facilities to "take all steps necessary to prevent accidents and fires," contingency plans for drilling sites and associated onshore activities are required to be prepared.

A comparison of contingency planning and associated emergency response guidelines and requirements is presented in Table 3.

Conclusions

This analysis of programs related to EPA's SPCC program reflects four major points. First, oil facilities are regulated by several federal agencies, and not only by EPA. Second, other federal programs often enforce much stricter requirements than those imposed by the SPCC program's current guidelines. Third, EPA possesses the authority to promulgate new mandatory requirements for the storage of oil, and may elect to do so in the near future. Finally, certain elements of good spill prevention practices are common to federal regulatory programs.

Reference

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EVALUATION OF THE ACCURACY OF VOLUMETRIC LEAK DETECTION METHODS FOR UNDERGROUND STORAGE TANKS CONTAINING GASOLINE¹

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ABSTRACT: A United States Environmental Protection Agency (EPA) research program evaluated the current performance of commercially available volumetric test methods for the detection of small leaks in underground gasoline storage tanks. The evaluations were performed at the EPA Risk Reduction Engineering Laboratory's Underground Storage Tank Test Apparatus in Edison, New Jersey.

The methodology used for evaluation made it possible to determine and resolve most of the technological and engineering issues associated with volumetric leak detection, as well as to define the current practice of commercially available test methods. The approach used (1) experimentally validated models of the important sources of ambient noise that affect volume changes in nonleaking and leaking tanks, (2) a large data base of product-temperature changes that result from the delivery of product to a tank at a different temperature than the product in the tank, and (3) a mathematical model of each test method to estimate the performance of that method. The test-method model includes the instrumentation noise, the configuration of the sensors, the test protocol, the data analysis algorithms, and the detection criterion.

Twenty-five commercially available volumetric leak detection systems were evaluated. The leak rate measurable by these systems ranged from 0.26 to 6.78 L/h (0.07 to 1.79 gal/h), with a probability of detection of 0.95 and a probability of false alarm of 0.05. Five methods achieved a performance between 0.19 L/h (0.05 gal/h) and 0.57 L/h (0.15 gal/h). Only one method was able to detect leaks less than 0.57 L/h (0.15 gal/h) if the probability of detection was increased to 0.99 and the probability of false alarm was decreased to 0.01. The measurable leak rates ranged from 0.45 to 12.94 L/h (0.12 to 3.42 gal/h) with these more stringent detection and false alarm parameters.

The performance of the methods evaluated was primarily limited by test protocol, operational sensor configuration, data analysis, and calibration, rather than by hardware. The experimental analysis and model calculations suggested that substantial performance improvements can be realized by making procedural changes. With modifications, it is estimated that more than 60 percent of the methods should be able to achieve a probability of detection of 0.99 and a probability of false alarm of 0.01 for leak rates between 0.19 L/h (0.05 gal/h) and 0.56 L/h

(0.15 gal/h), and 100 percent should be able to achieve this performance for leak rates of approximately 0.76 L/h (0.20 gal/h).

Leaking underground storage tank systems represent a serious environmental threat. Estimates of the fraction of underground storage tank systems that may be leaking range from 10 to 25 percent. Records from past release incidents indicate that without the use of release detection, a release can become substantial before it is detected.^{10,11}

There are many commercially available methods for detecting leaks in underground storage tanks. Those which are the most widely used in the petroleum industry are in a category called volumetric tank tests (also known as "precision," "tank tightness," or "tank integrity" tests). The premise of a volumetric tank test, and hence its name, is that any change in the volume of fluid within a tank can be interpreted as a leak. Detection of these leaks is difficult because there are many physical mechanisms that produce volume changes that can be mistaken for leaks. Most of the volumetric tanks tests on the market today claim the ability to detect leaks as small as 0.19 L/h (0.05 gal/h). (This is the "practice" recommended in the National Fire Protection Association (NFPA) Pamphlet 329⁵ for volumetric tests in tanks less than 47,316 L (12,499 gal) in capacity). These volumetric tank tests, however, do not specify the reliability of their test results in terms of probability of detection (P_D) and probability of false alarm (P_{FA}) against this 0.19 L/h leak rate. The 1984 Hazardous and Solid Waste Amendments to the Resource Conservation and Recovery Act of 1976 charged the U.S. Environmental Protection Agency (EPA) with developing regulations for the detection of releases from underground storage tanks. The new regulations, released in September 1988, state that all volumetric tank test methods must have the capability of detecting leaks as small as 0.38 L/h (0.1 gal/h) with a P_D of 0.95 and a P_{FA} of 0.05. These are only minimum standards, and the tank owner-operator may want better protection against the possibility of a testing mistake.

Development of technically sound and defensible regulations required that both the threat to the environment and the technological limits of release detection be known. The threat to the environment

1. Mention of trade names or commercial products does not constitute an endorsement or recommendation for use.