

TECHNICAL
FIELD GUIDANCE

SITE INVESTIGATION PROCEDURES

NOTES

SITE INVESTIGATION PROCEDURES

GUIDANCE SUMMARY-AT-A-GLANCE

- # While no two spills are alike and, therefore, the scope of each site investigation varies, it is possible to group the various activities into these categories:
 - Identifying the type and source of the spill;
 - Determining the site history and property ownership;
 - Determining the extent of surface, subsurface, and structural contamination; and
 - Documenting the site investigation.

- # We don't expect each spill responder to be or become an expert in all the skill areas encompassed by a site investigation. Standby and other spill response contractors can supply much of the needed expertise. The BSPR Central Office and more of the regional offices now have hydrogeologists on staff who can assist you. Nonetheless, the more you understand, the more reasonable and supportable your decisions will be.

- # Determining the type and volume of material spilled very early in the spill investigation process is important to determining what levels of personal and respiratory protection may be required. BSPR's authority to clean up spills using state and federal monies is also limited to spills of petroleum products.

- # Physical/chemical properties of the spilled material determine: (a) the identity of the spill's source (if not already known), (b) how the material may have spread in the environment, (c) how much of a health and/or environmental hazard the spill may represent, and (d) what initial and longer-term corrective action measures may be needed to clean up the spill.

- # When the source of the spill is known, you should be able to get information on the characteristics of the spilled material from the owner/operator or through other technical assistance agencies. However, it is still advisable to sample the material for laboratory analysis to verify the information provided. All analyses should be conducted by a laboratory approved by DEC to perform the specific analysis required.

- # Don't deliberately smell, handle, or taste product or material contaminated by product (e.g., soil) to establish its identity. For an unknown believed to be, or containing some kind of, petroleum product or for an older gasoline spill, ask the laboratory to analyze the sample for total petroleum hydrocarbons using a gas chromatograph. If the tentative conclusion is that the product is relatively fresh gasoline, the sample should be reanalyzed for benzene, toluene, ethylbenzene, and toluene (BTEX).

NOTES

SITE INVESTIGATION PROCEDURES

GUIDANCE SUMMARY-AT-A-GLANCE

(continued)

- # The source(s) of a spill is sometimes readily apparent or is identified when a spill is reported. In other cases, you will have to piece together information derived from interviews, from your inspection of the site and surrounding area, from records, and from testing and sampling data to isolate the most probable spill sources. Start your search by examining potential sources within a few hundred feet of the discovered spill or nuisance condition and then expand the search radius uphill, upgradient, or upstream. It is possible that the spill's source may never be conclusively identified. This is especially a problem in urban settings.
- # The process of identifying the spill source can also involve backtracking from a discovered nuisance condition to the probable source area. A common example is moving upgradient (in the case of liquid and gaseous product) or downgradient (in some cases with vapors) along sewer manholes from the location of the discovered nuisance condition.
- # Assuming you are allowed on the premises to continue your investigation, ask to examine the following records (see page 29):
 - Equipment installation and maintenance data.
 - Inventory records.
 - Precision testing records.
 - Repair records.
 - Records of the water content in, or any water pump-outs from the tanks.
 - Records for any previous tank removal or abandonment projects.
- # Documenting property ownership and responsibility for the spill is important -- we want spillers to clean up spills themselves or reimburse the state for funds spent in a state-directed cleanup. Documentation concerns, should not, however, outweigh the emphasis you place on your primary concern: protection of human health and the environment and mitigation of environmental damage.
- # Site investigation methods for determining the extent of contamination vary to some degree for surface, subsurface, and structural contamination due to a spill. Investigatory methods for each of these contamination types are discussed in this section (begins on page 38).

NOTES

1.4 Site Investigation Procedures

During the investigation of a spill and spill site a standby contractor or the spiller collects the information that you will use to judge the degree of human health and/or environmental hazard posed by the spill. This information establishes the need for and the extent of cleanup (state- or RP-directed), and, eventually whether the cleanup can be discontinued. For state-directed spill response, your site investigation also involves making on-the-scene inquiries and inspections and doing a records search, when necessary, to establish responsibility for the spill.

Site investigation is often thought of as a discrete step in the spill response process, as presented in the introduction to this manual and as diagrammed in Exhibits 1.4-1 and 1.4-2. In reality, however, a site investigation is a continuous activity that starts with receipt of the spill report and the first visit to the site and ends with preparation of the Investigative Summary Report (ISR). In some cases, only a brief examination of the spill site, a limited records search, and a review of some sampling data may be all that is needed for you to reach a reasonable judgment on the degree of cleanup necessary. In other cases, you, a spill contractor, or a spiller will spend several weeks or months collecting and analyzing data until an informed decision can be made.

While a set of investigation procedures may be useful for one spill and inappropriate for another, it is possible to group the various activities into these categories:

- # Identifying the type and source of the spill;
- # Determining the site history and property ownership;
- # Determining the extent of surface, subsurface, and (occasionally) structural contamination; and
- # Documenting the site investigation.

Otherwise, physical factors such as geological conditions; the presence and depth of sewers, basements, and wells; the amount of material spilled; the proximity of sensitive populations and surface water; the relative congestion of the area; and many other variables will determine the course of an investigation for a particular spill and site. Exhibit 1.4-3 provides another view of the objectives of the site investigation.

In this section, we provide general guidance for each of the basic site investigation activity areas outlined above, as well as guidelines for the design, conduct, and interpretation of sampling and analytical activities. We have presented the material in a rough chronological order, but keep in mind that a site investigation often proceeds on many fronts at once. We assume in this discussion of site investigation procedures that a response to any emergency condition that might exist is being or has been taken. More specifically, it is assumed that:

**Exhibit 1.4-1
Flow Chart of
Spill Response Process:
Initial Response and Investigation**

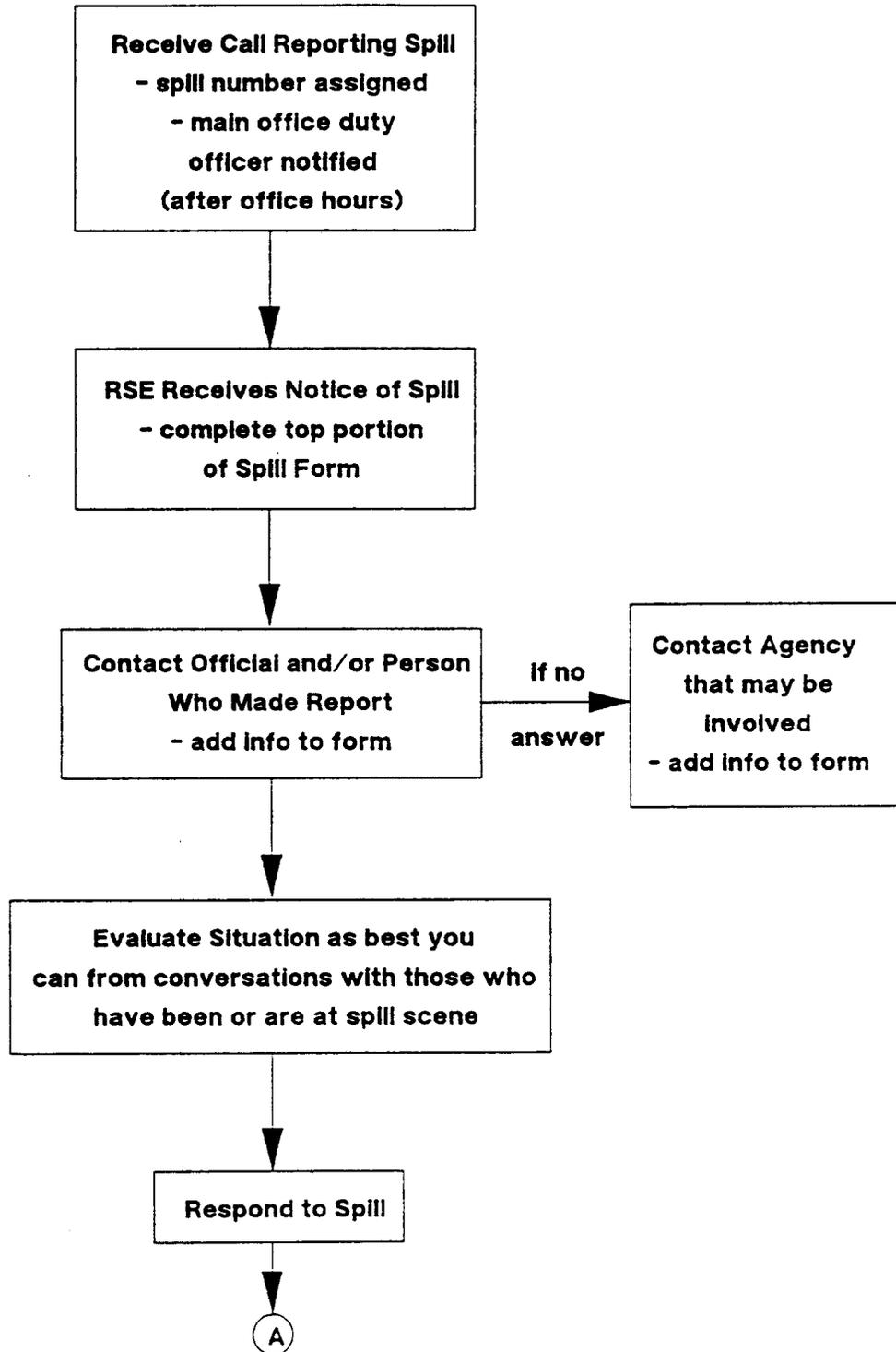
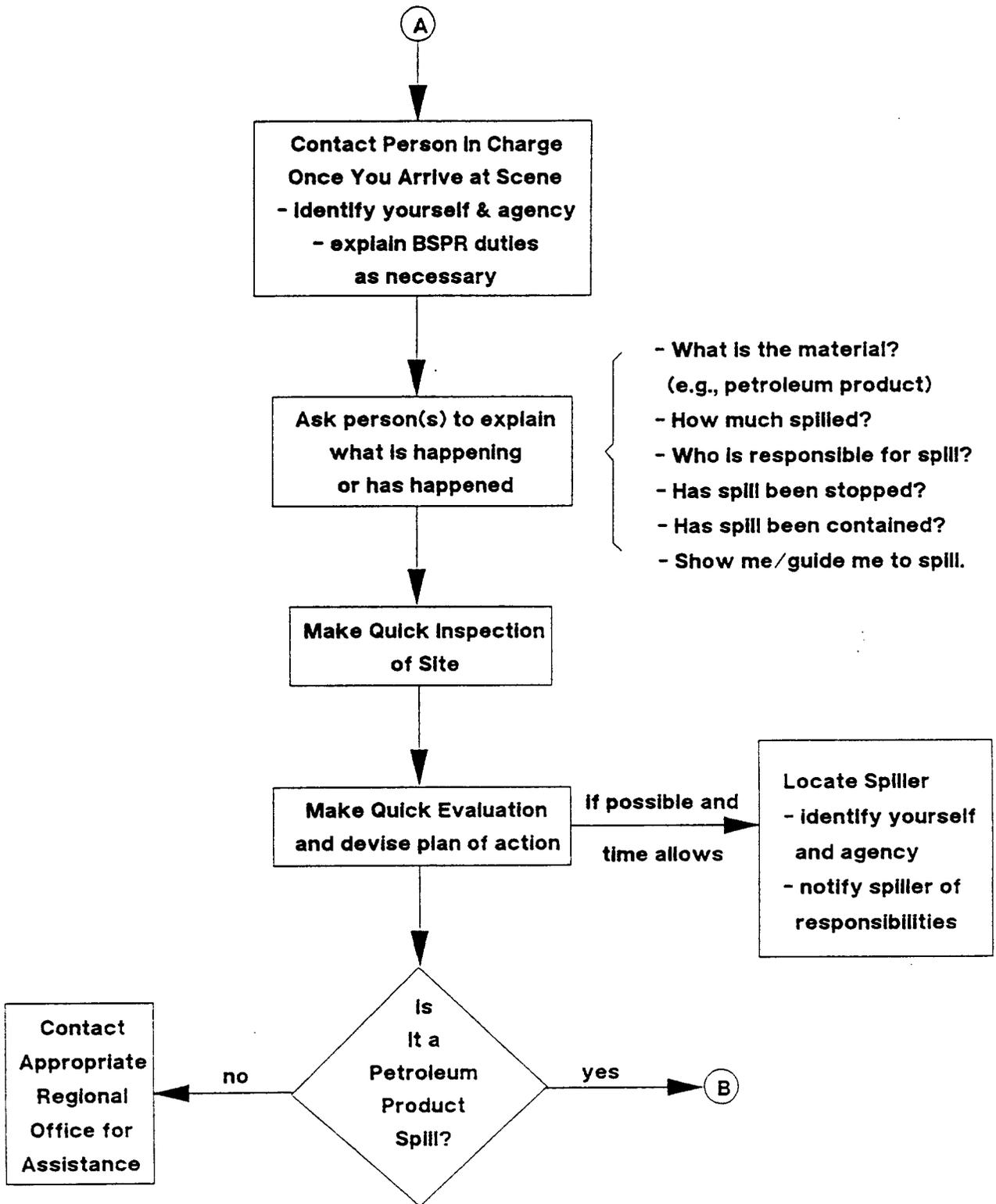


Exhibit 1.4-1
(continued)



**Exhibit 1.4-1
(continued)**

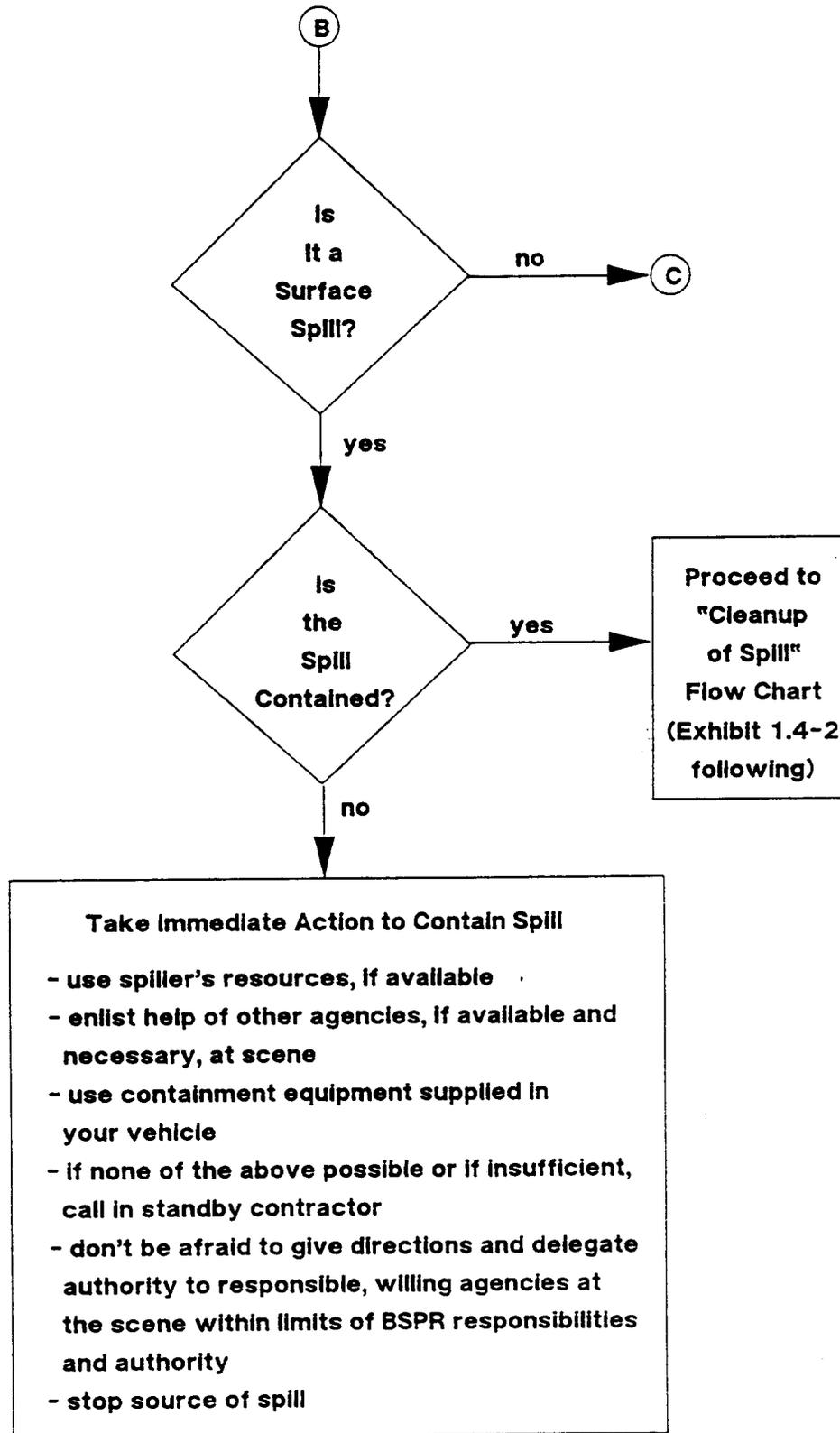
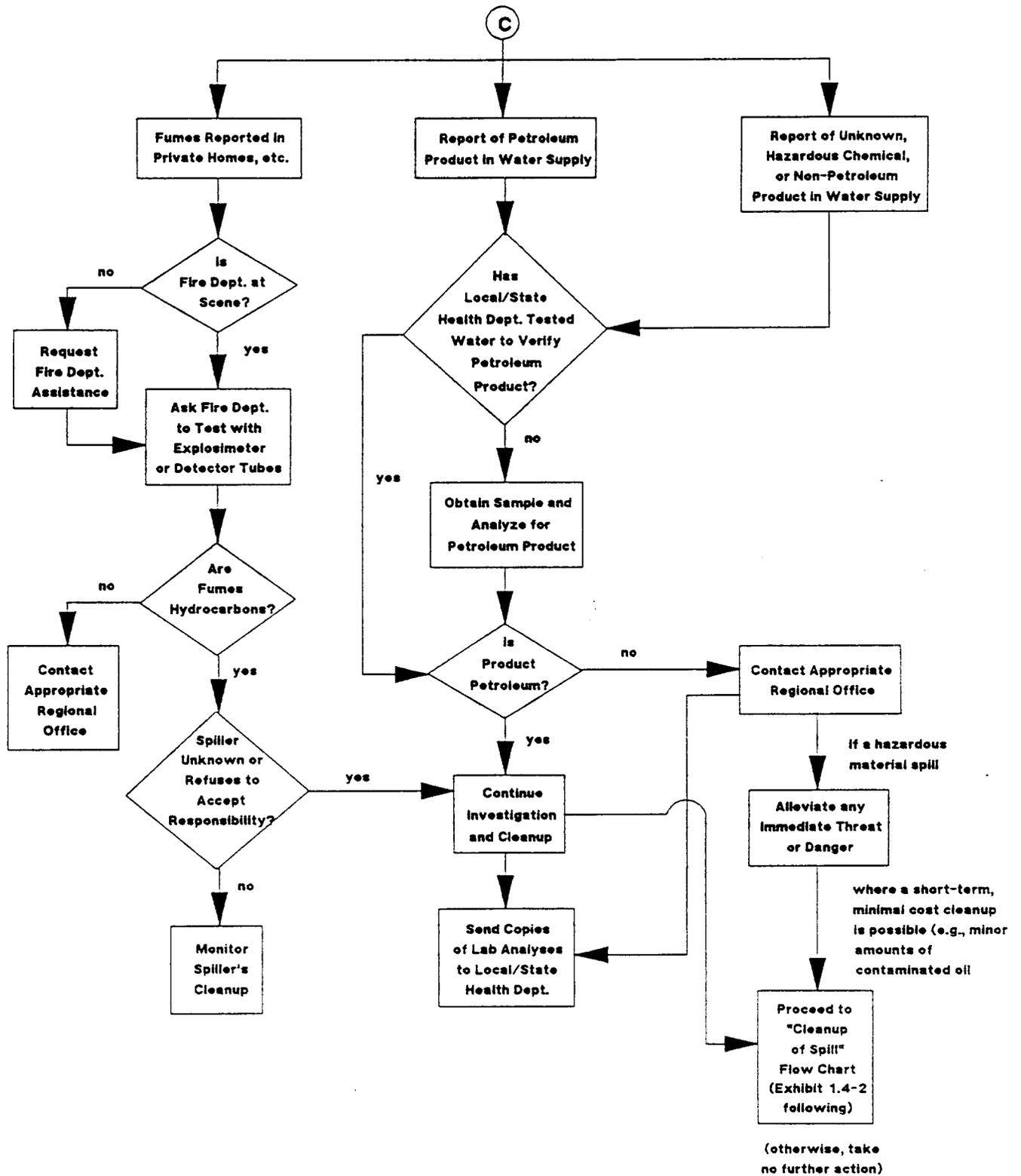


Exhibit 1.4-1
(continued)



**Exhibit 1.4-2
Flow Chart of
Spill Response Process:
Further Investigation and Cleanup of Spill**

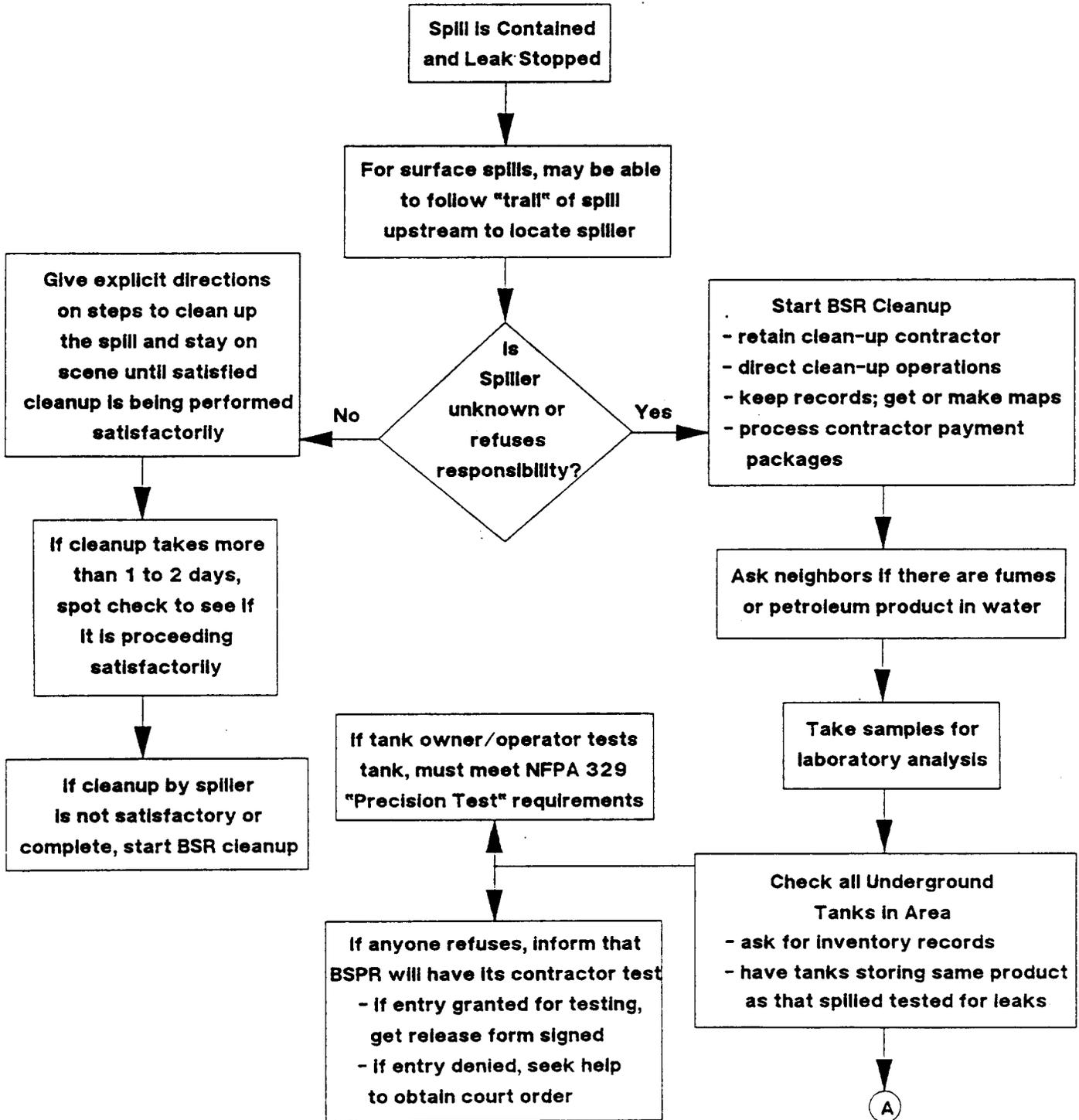


Exhibit 1.4-2
continued

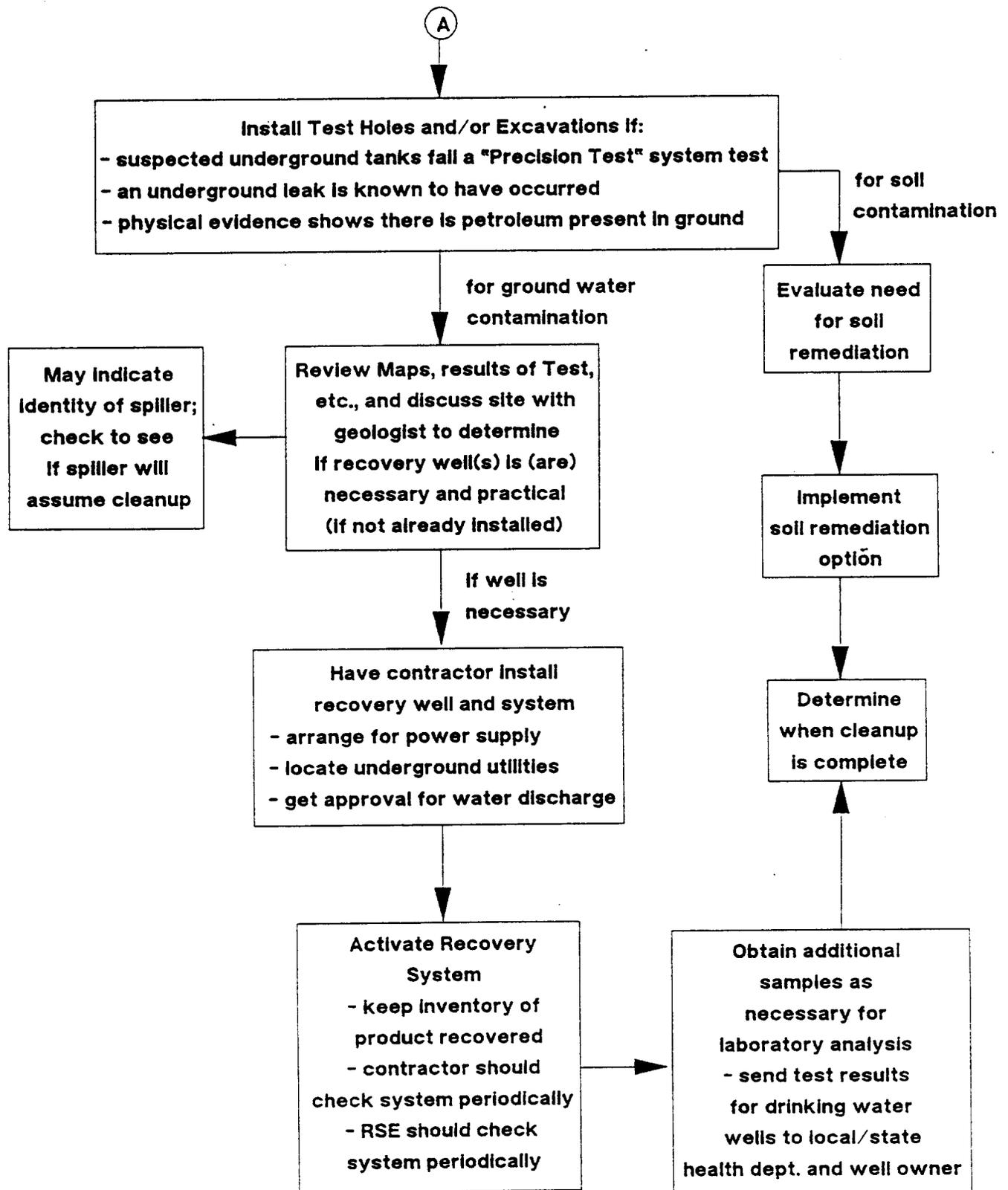


Exhibit 1.4-3

Site Investigation Objectives

1. Determine Spill Type and Type of Release (Sudden or Long-Term)
 - # underground storage tank
 - # aboveground storage tank
 - # tank truck
 - # other
 2. Determine Spill Location
 - # facility name & address
 - # facility type
 - # if transportation spill, name of road and corresponding mile markers and/or cross roads
 - # primary and principal aquifer determination
 3. Determine Product Type
 - # leaded gasoline
 - # unleaded gasoline
 - # diesel fuel
 - # fuel oil (#)
 - # kerosene
 - # jet fuel
 - # used oil
 - # other
 - # unknown
 4. Date Spill was Discovered
 5. Discovery Method (e.g., tank test failure, vapors in home)
 6. Determine if Fire/Explosion Hazard exists
 7. Determine Threatened and/or Impacted Resources
 - # soil
 - # ground water
 - # surface water
 - # storm sewer
 - # wetland
 - # other
 8. Determine Need for Immediate Clean-Up Actions
-

- # you have selected and called out a standby contractor, if needed (see Part 1, Section 2);
- # the immediate fire and safety hazards are being addressed (see Part 1, Sections 3.1 and 6.2);
- # the spill has been stopped, if the source is known (see Part 1, Section 3.2); and
- # readily apparent free product has been confined and removed (Part 1, Sections 6.2, 6.4, and 6.5).

Any on-site investigation cannot begin safely until all imminent health and safety hazards are under control and initial measures have been taken to minimize the impact of the spill.

Note that to properly conduct a site investigation you must possess or have access to a wide range of specialized skills. Whether you're directing the cleanup or overseeing an RP-directed cleanup, you'll need some expertise in (or, at a minimum, access to good references on) the chemistry, health effects, and environmental behavior of different petroleum and chemical products. We provide some background in these topics in this section (page 18) as well as guidance on structuring a search for the source of a spill (page 19). You'll need to know how to locate, work with, and/or interpret aerial photographs, tax records, and other legal documentation to establish property ownership and operational details (i.e., the possible identity of the spiller). For subsurface spills, like those from underground storage tanks, you need to be familiar with geological and hydrogeological principles (as well as have access to the experts) in order to make decisions about locating monitoring pits and/or wells and to interpret the complex, and sometimes confusing, monitoring data that are generated over time (see page 41).

We don't expect each spill responder to be or become an expert in all the skill areas encompassed by a site investigation. Standby and other spill response contractors can supply much of the needed expertise. The BSPR Central Office and more of the regional offices now have hydrogeologists on staff who can assist you. Nonetheless, the more you understand, the more reasonable and supportable your decisions will be.

Other portions of this manual containing guidance relevant to the conduct of site investigations include:

- # Introduction, Overview of the Spill Response Program, Section B, **Roles of the DEC Spill Responder** (provides an overview of spill responder's roles in the spill response process);
- # Part 1, Section 1.2, **Enforcement of Spiller Responsibility**, and Section 1.3, **Access and Right-of-Entry** (discusses BSPR procedures for notifying spillers of their responsibilities for spill cleanup, BSPR authority to enter private property to investigate a spill, and procedures for gaining access);

- # Part 1, Section 2, **Contractor Selection and Call-Out** (reviews procedures for calling out standby spill contractors to respond to a spill);
- # Part 1, Section 3.1, **Emergency Response to Fire and Safety Hazards**, and Section 3.2, **Confining and Containing Releases** (reviews spill responder's role in an emergency response and proper emergency response procedures);
- # Part 1, Section 6, **Corrective Action** (provides guidance on the investigation and initial remediation of vapor hazards in structures and sewers; free product in structures and sewers; free product on the soil surface; free product on surface water; contaminated soil; and contaminated ground water);
- # Part 2, Section 1, **Personal Health and Safety Protection** (provides guidance on health and safety practices and guidelines for spill responders);
- # Part 2, Section 2, **Equipment Training, Calibration, and Maintenance** (provides guidance on the use, calibration, and maintenance of field screening equipment);
- # Part 2, Section 3, **Proper Management of Spill Residuals and Debris** (discusses proper treatment and/or disposal of residuals or debris generated in spill response activities);
- # Part 2, Section 4, **Quality Assurance/Quality Control Procedures** (provides QA/QC guidelines for sample collection, analysis, and chain-of-custody procedures).

1. Identifying the Type of Spilled Material

Determining the type and volume of material spilled very early in the spill investigation process is critical. First, this information is important in determining what levels of personal and respiratory protection may be required so that you are prepared before you arrive on the spill scene. Second, BSPR's authority to clean up spills using state and federal monies is limited to spills of petroleum products. Although spill responders assist in the emergency response to a hazardous material spill, the cleanup of a hazardous material spill is the responsibility of the Hazardous Waste Remediation Division.¹ If the spilled material is a non-petroleum product, contact other regional DEC offices. For sewage or non-hazardous material spills (e.g., vegetable oil or dairy products) contact the Regional Water Quality Section. For gaseous releases, contact the Air Pollution Control Section. For hazardous material spills, contact the Bureau of Hazardous Waste Remediation.

¹ *Hazardous materials include substances listed in the Code of Federal Regulations (CFR) 40, Part 261, by EPA as hazardous wastes or any other hazardous raw materials.*

Knowing the physical/chemical properties of the spilled material you can determine: (a) the identity of the spill's source (if not already known), (b) how the material may have spread in the environment (e.g., it is very volatile or very soluble in water), (c) how much of a health and/or environmental hazard the spill may represent (e.g., it is flammable), and (d) what initial and longer-term corrective action measures may be needed to clean up the spill (e.g., the material binds tightly to soils). Exhibit 1.4-4 shows the likely partitioning of different petroleum constituents. Such information has a bearing on where (i.e., in which medium) a particular contaminant might be detected.

When the source of the spill is known (e.g., an overturned tanker truck or a leaking aboveground tank), you should be able to get information on the characteristics of the spilled material from the owner/operator or through other technical assistance agencies (see Part 1, Section 3, Emergency Response). Nevertheless, it is still advisable to order a laboratory analysis of samples of the material to verify the information provided by the owner/operator. Several typical field scenarios and the sampling response are presented in Exhibit 1.4-5.

Obtaining a sample of the material spilled is even more critical when the source of the spill is unknown or in dispute.² First, learn as much as possible from the physical characteristics of the material such as its color, odor, or viscosity. For example, super unleaded gasoline is often pink in color and a #6 fuel oil will be very viscous, almost asphalt-like (see also Attachments 1.4-1 and 1.4-2). Many petroleum products will leave a sheen on water. This characteristic can be tested for by means of the so-called "jar test" where contaminated soil is placed in a jar of water, shaken, and allowed to settle to see if an oil sheen forms on the water surface. **Don't deliberately smell, handle, or taste product or material contaminated by product (e.g., soil) to establish its identity** as these techniques present a significant health risk.

Second, you can also use some direct-reading instruments to establish the presence qualitatively and, in some cases, the identity of a contaminant.³ If substance spilled is believed to be volatile, the following instruments can be used to obtain direct readings of vapors coming off the spill mass, contaminated water, or an area or sample of contaminated soil:

- # **Photoionization Detector** detects most organic and selected inorganic compounds;

² *Make sure to establish a Project Identification Number (PIN) first. Later, when the responsible party has been identified, the costs incurred by the state for sampling can be billed to the spiller.*

³ *Calibrate these instruments to the manufacturer's instructions before and after every use. Refer to Part 1, Section B, Equipment Training, Calibration, and Maintenance, for more information.*

Exhibit 1.4-4

**Likely Partitioning of Petroleum
Product Constituents**

Will Predominantly Absorb to Soil Particles	Will Predominantly Volatilize into the Air or Soil Gas	Will Predominantly Solubilize in Water	Will be Found in Multiple Media
benzo(a)pyrene	(n)hexane	phenol	benzene
phenanthrene	(n)heptane	MTBE	ethyl benzene
benz(a)anthracene	(n)pentane		naphthalene
tetraethyl lead	1-pentane		toluene
			(o)xylene

Exhibit 1.4-5
Sampling Recommendations for Different Field Scenarios

Situation	Type of Sampling Suggested
Report of petroleum odor in well water. Investigation shows several possible sources in area.	Use DOH Method 310-13 to identify the type of petroleum product in the well. To help cross-match, also take a sample from each potential source for comparison.
Downgradient monitoring well is free of product presently, but there has been a spill at an upgradient gasoline station.	To match the gasoline in the station, use DOH Method 310-13 to identify petroleum products in water. Obtain sample from station for comparison. Use 503.1 to detect dissolved BTX. Use a modified Method 624 to detect MTBE.
Report of gasoline odors in home. Investigation confirms odors smell like gasoline.	Coordinate indoor air sampling with DOH following DOH Indoor Air Sampling Protocol.
Discover soil pile at a service station that is being remodeled. Soil has an oily odor.	Use DOH Method 310-13 after extraction or 312-4 for soil to determine if petroleum contamination.
Several abandoned drums found in an empty field. Drums contain a black liquid and there is a varnish-like odor.	Use Methods 624 and 625 to determine if substance is a petroleum product or a solvent.
Recovery system installed for a diesel spill is discharging "clean" water to a nearby stream. Should an air stripper be used to treat the "clean" water?	Use Method 610 for PAH and 503.1 or 524.2 for comparison to state standards for such a discharge. An oil and grease analysis may be needed.
Reports of chemical odor (like a solvent) in the well water of several homes. No known gasoline station in area. A previous BTX analysis of well water samples indicated no detectable levels.	Use Methods 601 and 503.1 to identify if the substance is a solvent or a petroleum product.
Report of a petroleum odor in a well. No source can be identified. Homeowner heats with gas.	Use Method 503.1 to identify if odor is petroleum with the exceptions of fuel oil and diesel. Use Method 914C in the Standard Methods to check for pseudomonas.
Unknown substance seeping from stream bank into stream.	Use Methods 624 and 625 to analyze a liquid sample. If a liquid sample cannot be obtained, use Methods 8240 and 8270 to test sample.

NOTES

- # **Organic Vapor Analyzer** measures trace levels of organic vapors;
- # **Detector Tubes** can identify a specific chemical group in a short amount of time based on a color change in the material inside the tube; and
- # **Explosimeter (or Combustible Gas Indicator)** measures vapor concentrations sufficient to support an explosion.

Be conservative in your reporting of readings for an unknown contaminant using these instruments. Report your readings, for example, as a "needle deflection" or "positive instrument response" rather than referring to a specific concentration value. A reading of zero should be reported as "no instrument response" rather than as "clean" or "no contamination". As a general rule, these instruments cannot detect vapors at concentrations below 1 ppm. These instruments have also shown a poor correlation with laboratory results, especially in situations where the spill has weathered (i.e., much of the volatile fraction has volatilized) or when the soil is contaminated by migrating vapors as opposed to free product. These instruments should not be used at diesel tank spills since diesel fuels contain far less volatiles than does gasoline. Some direct-reading instruments that detect a particular class of substances (e.g., detector tubes) are also subject to interferences (i.e., may also react to other substances) and may give a false reading.

Finally, collect samples of the spilled material for laboratory analysis. All analyses should be conducted by a laboratory approved by DEC to perform the specific analysis required. Make sure that the samples collected are of adequate quality to ensure an efficient and informative analysis. The following factors affect the quality of samples collected and, thus, the analytical results:

- # Decontamination of equipment;
- # Preparation of sample containers;
- # Sample preservation;
- # QA/QC procedures for sample collection; and
- # Chain-of-custody recordkeeping.

Follow the guidance provided in Part 2, Section 4, Quality Assurance/Quality Control Procedures, concerning these factors for the collection and analysis of field samples.

a. Sample Analysis Considerations

Gasoline is a mixture of over 200 petroleum-derived chemicals plus several synthetic additives (see Attachment 1.4-1 at the end of this section). The majority of gasoline components range from C4 to C12 hydrocarbons, and include both straight-chain and aromatic hydrocarbons. Diesel fuels, on the other hand, consist primarily of C10 to C23 straight-chain hydrocarbons (the C16 and C17 hydrocarbons predominate) with very few aromatic constituents. These differences in composition must be

NOTES

kept in mind when deciding upon chemical analyses for petroleum constituents in samples.

For a suspected spill of a gasoline product, samples should be analyzed for benzene, toluene, ethylbenzene, and total xylenes (BTEX), methyl-tertiary butyl ether (MTBE), and total petroleum hydrocarbons (TPH). This group of constituents is found in most gasoline blends in fairly high concentrations and comprise the more mobile (to varying degrees) fraction (see also Attachments 1.4-1 and 1.4-2 to this section). Benzene, in particular, is of concern because it is a known human carcinogen, is very volatile, and has a relatively high water solubility. However, because BTEX are more mobile than the remaining constituents, an analysis of BTEX alone, without characterizing the entire contaminated soil profile, cannot be used to quantify the amount of petroleum contamination in soil. In addition, BTEX is present in much lower concentrations in fuel oils (actually toluene will be present in a fuel oil in higher concentrations than benzene or xylene) and, therefore, is not a reliable indicator. Older (two or more years) gasoline spills of gasoline will have also lost most of the BTEX fraction (see Attachment 1.4-1 for an expanded discussion of weathered spills). The older the gasoline spill, therefore, the more it will look like a fuel oil when analyzed in the laboratory. Few laboratories have the capability to analyze for other constituents known to be part of commercial gasoline blends that could still be found in a weathered sample.

It is hard to distinguish between weathered gasoline product and fuel oil. If you have a possible old leaded gasoline spill, you can ask the laboratory to analyze the sample for lead, but since lead doesn't travel very far in soils, the laboratory may not find it in a sample taken at some distance from the source of the spill. In addition, unless the laboratory can analyze for organic lead, a total lead analysis will also measure natural organic and inorganic lead levels and not just lead levels due to the spill alone (i.e., it is possible to obtain a false reading, especially for soils high in inorganic lead). Reliable measures of organic lead contamination can only be obtained where background total lead concentrations are known or can be analyzed.

For these reasons, therefore, we recommend that a TPH analysis also be conducted to check for other less mobile petroleum constituents. For an unknown believed to be, or to contain some kind of, petroleum product, for older spills, or for known spills of diesel and fuel oils, the laboratory should be asked to analyze the sample first for TPH using a gas chromatograph (GC). This analysis detects straight-chain hydrocarbons and aromatic constituents, and the results are reported as the sum of all hydrocarbons in the sample, rather than as individual chemicals. The GC analysis should then be compared against the patterns for different petroleum product standards to determine if the pattern resembles, for

NOTES

example, gasoline-type product or a fuel oil. If the tentative indication is that the product is gasoline, the sample should be analyzed for BTEX.⁴

Refer to Exhibits 1.4-6 and 1.4-7 for additional guidelines on analytical methods. For more guidance on sampling and analysis procedures, including guidance on where to sample, see the subsection on **Determining the Extent of Contamination** on Page 38.

NYSDEC does have monthly sampling and yearly laboratory analysis requirements for monitoring wells at major petroleum storage facilities, i.e., those facilities that have an aggregate storage capacity of 400,000 gallons or more of petroleum. All sampling and testing must be conducted by a private or "out-of-house" laboratory approved by NYSDOH to perform the specific analyses required. The Department will allow the facility operator to perform monthly monitoring for free product.

Each monitoring well at a major facility must be sampled monthly for free product (either by visual means, use of product paste, or electronically). Three to five well water volumes must be purged before taking a sample. If free product is found, the facility operator must notify NYSDEC immediately and testing for purgeable aromatics and petroleum products in water becomes unnecessary.

Initially after installation and then six months after the initial testing, all monitoring wells must be sampled and tested for purgeable aromatics (EPA 503.1) or petroleum products (DOH 310-13) in water. Based on both the first and six-month testing results, NYSDEC will then establish a facility-specific testing schedule with at least one laboratory test performed annually. All results from laboratory analysis must be submitted to the appropriate regional office.

2. Identifying the Source(s) of Spill

The source(s) of a spill is sometimes readily apparent or is identified when a spill is reported. In other cases, you will have to piece together information derived from interviews, from your inspection of the site and surrounding area, from records, and from testing and sampling data to isolate the most probable spill sources (there can be more than one). The type of product spilled (see subsection 1 above) will provide clues as to the probable source(s). Gasoline

⁴ While TPH levels generally indicate fuel contamination, certain sites may have natural or historical use characteristics (e.g., natural hydrocarbon production) that make interpreting the analytical results difficult. Reported soil concentrations of volatile organic chemicals may also vary with soil type. Complete recovery of volatiles during sample collection is difficult in sandy soils due to losses from evaporation, and adsorption may limit extraction efficiency in clayey soils. Soils with high organic and/or clay materials are more difficult to analyze than those with minimal amounts of these materials.

Exhibit 1.4-6

Alternative Analytical Methods

Analytical Methods	General Description	Applicability	Limitations
<p>T O T A L P E T R O L E U M H Y D R O C A R B O N S (TPH or PHC)</p>	<p># Uses GC/FID analysis to measure concentration of total petroleum hydrocarbons extracted from sample using a solvent</p> <p># Must specifically request "fingerprint" analysis for identification of types of petroleum hydrocarbons</p>	<p># Can be used to analyze water and soil samples</p> <p># Most applicable for determining presence of oils (i.e., fuel oil, waste oil, etc.)</p> <p># Can provide information on "weathered" product</p> <p># Should specify if analysis of dissolved fraction of ground water is desired</p>	<p># Need to specify to laboratory the type of data desired</p> <p># Possible to use to identify presence of gasoline product but loss of gasoline can occur during extraction</p> <p># Identification of product types can be approximate unless samples of pure product (i.e., from the suspected source) are analyzed</p>
<p>I N F R A R E D (I R - - E P A Method 418.1)</p>	<p># Measures concentration of total petroleum hydrocarbons extracted from sample using freon</p>	<p># Can be used to analyze water and soil samples</p> <p># Most applicable for determining presence of oils</p> <p># Can be used to measure lighter oils</p>	<p># Does not provide identification of types of hydrocarbons</p> <p># Subject to interference since analysis also measures non-petroleum hydrocarbons (e.g., organic acids)</p> <p># Possible for gasoline sites, however, loss of up to 1/2 of total gasoline can occur during extraction</p>
<p>O I L A N D G R E A S E (S t a n d a r d Method 503)</p>	<p># Measures weight of oil and grease extracted from sample using freon</p>	<p># Can be used to analyze soil and water samples</p> <p># Better for heavy oils</p>	<p># Inappropriate for gasoline or oils with volatile fraction (e.g., waste oils with solvent contamination) due to loss of volatiles during extraction</p>
<p>G A S C H R O M A T O - G R A P H Y (GC- EPA Method 602- water; EPA Method 8020- soil)</p>	<p># Measures purgeable aromatics (volatile fraction) using purge and trap method</p> <p># Provides data on benzene, toluene, ethyl benzene, and total xylenes (BTEX). (May need to request xylene data specifically.)</p> <p># Compound I.D. is not definitive, i.e., compared to mass spectrometry (MS) results, which are verifiable</p>	<p># Good for gasoline</p> <p># Can detect some solvents in waste oils</p>	<p># Not optimum for fuel oils (particularly heavier oils) since those compounds lack significant volatile fractions</p>

Exhibit 1.4-6

Alternative Analytical Methods (continued)

Analytical Methods	General Description	Applicability	Limitations
G C (E P A Method 601-water; EPA Method 8010-soil)	# Measures purgeable halocarbons using purge and trap method # As with Method 602, compound I.D. cannot be confirmed	# Best for detecting presence of solvents in waste oils	# Not applicable for petroleum hydrocarbons
G C / M a s s Spectrometry (MS) (EPA Method 624-water; EPA Method 8240-soil)	# Measures purgeable halocarbons and aromatics # Provides positive identification of BTEX constituents	# Most applicable for gasoline	# Not optimum for fuel oils (particularly heavier oils) since those compounds lack significant volatile fraction

Exhibit 1.4-7

EPA Analytical Methods

Analytical Group	Constituent	Analytical Method
Gasoline (motor gasoline, aviation gasoline, and gasohol)	1,2-Dichloroethane	EPA Method 8010
	Benzene	EPA Method 8020
	Toluene	EPA Method 8020
	Ethylbenzene	EPA Method 8020
	Total Xylenes	EPA Method 8020
	Total Volatile Organic Aromatics	All detectable compounds by EPA Method 8020
	1,2-Dibromoethane	EPA Method 8010 with ECD substituted (EDB) for Hall detector, 2 column confirmation
	Methyl-Tertiary-Butyl-Ether	EPA Method 8020
	Total Petroleum Hydrocarbon	EPA Method 418.1
	Middle Distillates (kerosene, diesel, jet fuel, and light fuel oils)	Napthalenes 2-methylnaphthalene, 1-methylnaphthalene, and others with peaks greater than 10 ppb
Benzene		EPA Method 8020
Toluene		EPA Method 8020
Total Xylenes		EPA Method 8020
Ethylbenzene		EPA Method 8020
n-Propylbenzene		EPA Method 8020
Total Volatile Organic Aromatics		All detectable compounds by EPA Method 8020
Volatile Organic Halocarbons		All detectable compounds by EPA Method 8020
Total Petroleum Hydrocarbon		EPA Method 418.1
Other or Unknown		Priority Pollutant: Metals
	Priority Pollutant: Volatile Organics	EPA Method 8240
	Priority Pollutant: Extractable Organics	EPA Method 8270
	Non-priority Pollutant: Organics (with GC/MS peaks greater than 10 ppb)	EPA Methods 8240 and 8270
	Total Petroleum Hydrocarbons	EPA Method 418.1

NOTES

contamination in a drinking water well suggests a source like a nearby gasoline station, automobile dealer or repair shop, or bus fleet operation among the many types of businesses that can operate gasoline tanks (see Exhibit 1.4-8). Fuel oil in a well, on the other hand, suggests the possibility of a home heating oil tank leak or overfill or problems with the tanks of a fuel oil distributor down the street. Compare what you come to learn about the type of spill with what you learn about possible sources in the area.

It is possible, of course, to never identify the spill's source conclusively. This is especially a problem in urban settings, like New York City, for several reasons. First, city zoning regulations tend to group similar sources with the result that there may be numerous gasoline stations in one area.⁵ Second, there is considerable turnover in property ownership, many sublease arrangements, and/or many abandoned properties in some cities like New York. The task of unraveling the property ownership trail may be so time consuming that the spill responder might better spend the time just cleaning up the spill.⁶ Third, there tend to be many more conduits and utility lines underlying an urban site. These conduits and lines will act as preferential flow paths to distribute the spill over a wide area making tracking the spill back to its source almost, if not entirely, impossible.⁷

Under conditions such as these, your role is essentially to be the detective who pieces together information from a variety of sources. If any persons involved in or were witnesses to a reported spill, obtain spill-related information directly from them. Police reports may also contain such information. Residents also frequently know a great deal about the past history of a site (e.g., that it was a former gasoline station), including who may have owned the site previously, or about businesses in the vicinity that could be the source (e.g., local residents saw a tank being removed from the ground at a particular gasoline station). The local fire department will also typically know a great deal about possible area sources and may have records concerning tank installations and removals. Local fire or police department personnel may have already talked to the suspected spiller(s) as well and may have had better success in getting some information. In smaller towns, real estate agents and the postmaster will often know quite a bit about the past owners of local properties. There may also be a town or local area historian who may be a good resource as well.

⁵ *This particular factor is, of course, not peculiar to city settings. Several potential sources may also be grouped together at a single intersection or along a single stretch of road in suburban and rural settings as well.*

⁶ *In addition, the property owner may not be the spiller.*

⁷ *There also tend to be more broken or leaking water mains in the city (especially the older cities) that will influence the flow of a subsurface spill.*

Exhibit 1.4-8

Possible Petroleum Spill Sources

Service Stations
Motor Vehicle Garages
Automobile Dealerships
Convenience Stores
Municipal Garages
Abandoned or Converted Service Stations
Fleet Operators (e.g., taxicab and vehicle rental companies)
Cleaning Establishments
Industrial Plants, including refineries, terminals, & bulk plants
Schools, Hospitals, & Other Institutions
Airports
Pipelines
Abandoned Oil & Gas Wells
Subsurface Disposal and Injection Systems
Home Heating Oil
Oil for Farming Use

Source: American Petroleum Institute. June 1980. Underground Spill Cleanup Manual. API Publication 1628.

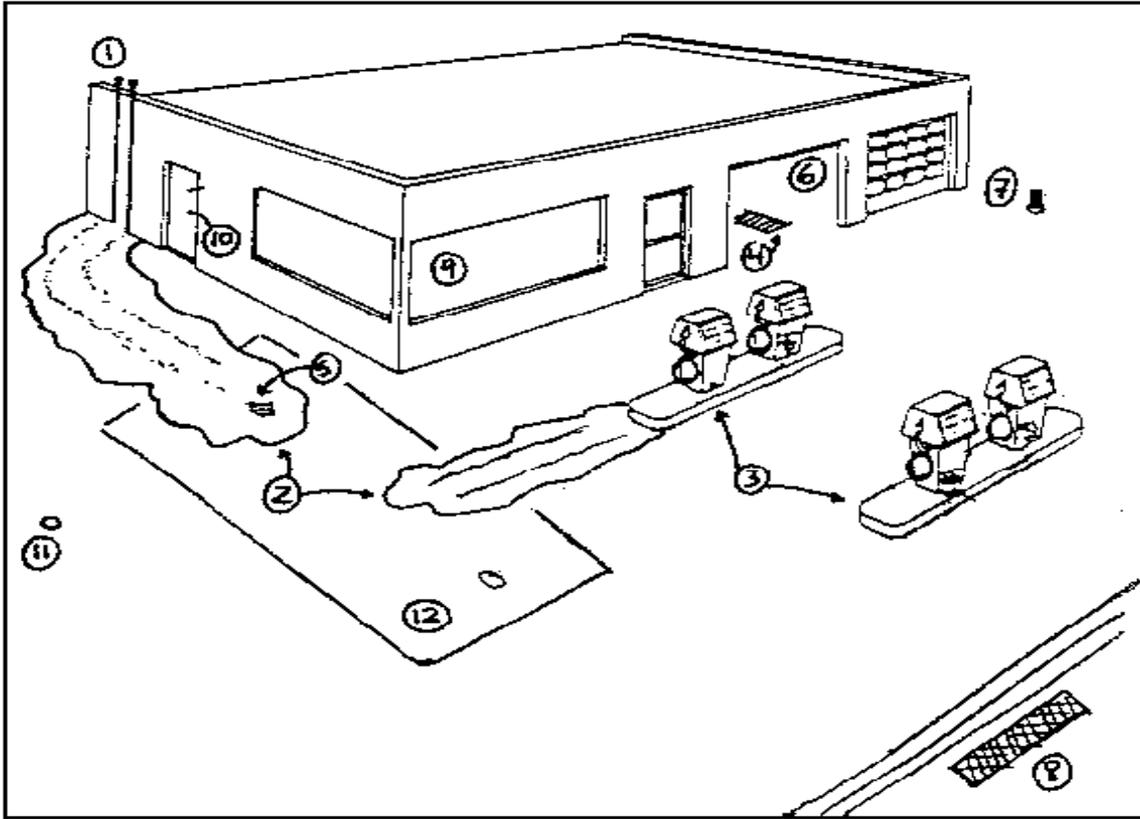
Your on-site inspection of possible sources may also turn up evidence of a spill. The key is to know what to look for as evidence of a spill or release at different types of facilities.

At a gasoline service station, there are several areas you should check where evidence of a spill might be uncovered. Each of these areas is referenced on a schematic of a typical gasoline service station in Exhibit 1.4-9.

- # Area #1 -- Vent Pipes. Check their condition. Does the number of vent pipes correspond to the number of known tanks?
- # Area #2 -- Pavement Patching. Evidence that the pavement has been patched/repared may indicate that subsurface problems (e.g., tank leak, piping leak, pump failure) may have occurred in the past or fairly recently. Check age and condition of the patched area. Look for oil stains, subsidence, buckling of pavement, etc.
- # Area #3 -- Pump Islands. Look for cracks and/or stains at base of pumps. Check to see if pumps are in good repair and not tilted as if they were struck. Check to see if piping is disconnected. Look for evidence of meter tampering, abraded hoses, and gasoline-eroded asphalt in paved area near island.
- # Area #4 -- Storm Drains. Are trench or "zipper" drains clean of oil and silt? Where do these drains lead? Any evidence of staining indicating gasoline or oil has been flushed into these drains? Any indication of excavation or other repair work around these drains?
- # Area #5 -- Fill Boxes. Check to see if soil around fill boxes has been eroded by water/gasoline spills (any petroleum odor to soil?). Are box and pipe tilted in the ground? Is the box cap missing? Any excavation/repair work in evidence? Gauge boxes and pipes.
- # Area #6 -- Repair Bay(s). Look for cracks in the pavement in this area or for signs of concrete patching. Look for drains and evidence of frequent and significant spills (e.g., concrete staining, discoloration).
- # Area #7 -- Waste Oil Collection Area. Waste oil may be collected and stored in an aboveground tank, underground tank, or in drums. Look for evidence of spills around any filler spouts or containment areas. Check to see if waste oil

Exhibit 1.4-9

Schematic of a Gasoline Station: Areas to Check for Evidence of Spills



- | | |
|-----------------------|----------------------------|
| 1 = Vent pipes | 7 = Waste Oil Collection |
| 2 = Pavement patching | 8 = Street Drains |
| 3 = Pump islands | 9 = Station records |
| 4 = Storm drains | 10 = Bathroom(s) |
| 5 = Fill boxes | 11 = Vapor recovery system |
| 6 = Repair bay(s) | 12 = Underground tanks |

NOTES

has been disposed of in on-site dry wells or pits. Has waste gasoline been disposed of with the waste oil? If yes, establish dates. Check the inventory of any waste oil tank. Use a tape with water paste if you suspect that the tank is below the water table.

- # Area #8 -- Street Drains. Check for evidence of product dumping in nearby sewers and batch basins. Check for petroleum vapors.
- # Area #9 -- Station Records. Check inventory book; Petroleum Bulk Storage License (PBS) if eligible; tank/piping test records; waste oil disposal receipts; violation orders from other agencies (if any); and other property/tank owner records, including leases. Check the alarm panel for the leak detection system. Is the power switched off?
- # Area #10 -- Bathroom(s). Look for dumping of waste oil and/or gasoline down bathroom toilets or sinks. Some station owners/operators decant the water from their gasoline tanks into these facilities, which can lead to potentially explosive vapors in sewers. Confirm whether bathroom drains lead to sewer or septic system.
- # Area #11 -- Vapor Recovery System. Some vapor recovery lines have condensate basins. Check to see if there is any product accumulation or evidence of a leak.
- # Area #12 -- Underground Tanks. Gauge tanks with a water paste tape to check for water contamination, which may indicate ground-water infiltration. As a general rule-of-thumb, smaller tanks usually mean an older station. Check to see if PBS license conforms to what you find.

We recommend that each regional office develop schematics such as for other kinds of facilities prevalent in their area.

A general search strategy for locating the spill source(s) would be as follows. Generally, the source of a flammable liquid will be near the location of the discovery of unconfined liquids or vapors. Start a check of the potential sources within a few hundred feet of where the nuisance condition or spill was discovered. Begin with the nearest and most obvious potential source(s) and work outward from there. All potential sources should be investigated regardless of the age of the source. Move uphill, upgradient of the presumed ground-water flow direction (based on surface topography), or upstream of the sewer or conduit flow in expanding your search radius. If this initial search fails to discover an obvious source, go back to the nearby potential source(s) and request that the owners/operators test their equipment for leaks while you continue to expand the search radius.

The process of identifying the spill source may involve backtracking from a discovered nuisance condition to the probable source area. A common example of the backtracking scenario occurs in the investigation of free product and/or vapors in

NOTES

sewers. Move upgradient (in the case of liquid and gaseous product) or downgradient (in some cases with vapors) from the location of the discovered nuisance condition along the branches of a sewer line while measuring vapor concentrations and/or looking for an accumulation of free product in the each manhole.⁸ Measure vapor concentrations with a combustible gas meter or photoionization detector equipped with a long sampling probe; do not enter the sewer to obtain a reading. Free product can be detected using absorbent material tied to a length of string or rope, which may be left secured in the manhole to help isolate the contaminant entry point. Eventually, you will reach a manhole where you can no longer see/detect free product or get a vapor reading; backtrack to your last positive reading or observation and you're probably in the vicinity of the source of the spill.

There are also geophysical and soil gas survey methods that can be employed to isolate sources of subsurface spills. For example, a metal detector or terrain conductivity unit (in the in-phase survey mode) can be used to locate underground tanks. A terrain conductivity meter can also be used to detect soil conductivity changes (i.e., decreases in conductivity below background readings), which indicates the presence of organics in the subsurface. Soil gas samples can be collected at fairly shallow depths (one to four feet) over an area (e.g., between two suspect tanks) to detect volatile contamination emanating from one or more sources. Each method is fairly non-intrusive and can be conducted with a minimum of disruption to ongoing site operations, taking as little as one day, depending on the size of the area to be covered. Special equipment and training are required, however, and both methods cannot be used in all geologic settings (e.g., the use of soil gas in heavy clay soils must be done cautiously). Both methods are limited in their ability to detect low levels of contamination.

Knowing that you've found what you're looking for is also not easy. Your search for the source of a particular spill may turn up evidence of another old spill separate from or even mixed in with the more recent spill. Make sure that the source you identify matches what is known about the spill (e.g., the possible volume of material spilled) before you stop this phase of the site investigation.

The final phase of identifying the spill source is obtaining data that confirms one or more probable sources as the actual source(s) of the spill. For example, you may have backtracked the spill to an intersection with a gasoline station on each corner. Approach each owner/operator to ask about their tanks. In doing so, follow the guidelines discussed in Part 1, Section 1.3, Access and Right-of-Entry. Assuming you are allowed on the premises to continue your investigation, look for indications of recent excavations or patched concrete or asphalt. Inspect the product dispensers to see if they have been dented as if hit by a vehicle, as this may indicate damage to the underground piping. Operate the remote pumps to see if they are leaking and check for evidence of any spill in this area. Ask to examine the following records:

⁸ *Some vapors can migrate upstream for a few hundred feet. This is a common occurrence during the winter months when the air in the sewer is warmed by the sewer flow and vents upward. This is the same effect as that which occurs in a chimney.*

NOTES

- # **Equipment installation and maintenance data.** Check if the installation and maintenance records reveal any inadequacies in practices or procedures, or whether the tank may be located within the seasonal water table. Determine if there was a recent overfill or other surface spill.
- # **Petroleum Bulk Storage certificates.** The owner of any petroleum storage facility having a capacity of over 1,100 gallons must register the facility with NYSDEC and renew this registration every five years. These registration certificates contain information on the ownership and operation of the facility, and contain other data on the design and operational features of the facility.
- # **Inventory records.** Discrepancies in the daily tank inventory records can identify a leaking tank system. These records can be used to estimate the cumulative amount of the spill. Determine if accurate daily inventory records are maintained. If the records are poor, the facility should be regarded as a potential source and a candidate for precision testing. If the records are properly maintained and reconciled, review them for discrepancies and loss trends.
- # **Precision testing records.** Examine the precision testing records to determine the past performance of the tank system (i.e., tanks and piping). Be suspicious of any indication that problems were experienced in testing the system or that multiple tests were conducted over a short period of time.
- # **Repair records.** Examine the records concerning any repaired components of the tank system as these will often be the source of a spill, either before or after the repair was completed.
- # **Records of the water content in, or any water pump-outs from, the tanks.** The presence of water in a tank UST may indicate a hole in the tank wall or a loose joint that has allowed ground water to flow into the tank and probably product out of the tank as well.
- # **Records for any previous tank removal or abandonment projects.** Examine any available documentation of the condition of the tanks when they were removed and of the tank excavation. Look for evidence that product, water, and/or soil was removed from the excavation. If the tank system was abandoned in place, determine if product was removed from the tank(s) and whether any product may have remained.

For state-directed spill response, the worksheets included as Attachment 1.4-3 at the end of this section may be used in organizing the information collected.

Unless the owner/operator can provide you with recent tank system precision test results (no more than a year old), ask that his or her tank systems (piping and tanks) be tested for possible leaks. If the owner/operator refuses or is unable to test the tank systems, ask for his or her permission to let DEC test the tanks, indicating that if the test shows that the system is leaking and is the source of the spill that the owner/operator will be billed for the cost of testing. If permission is granted, follow the testing guidelines discussed below. If permission is not granted, inform the owner/operator that he or she may still be identified as the spiller and held responsible for cleaning up the spill.

The basic tank testing methods include volumetric leak test methods and nonvolumetric leak test methods. A volumetric leak test is the most accurate tank testing method for detecting a leak in a storage tank or delivery system. This tank testing method involves sealing and pressurizing a tank or piping system to test for leaks based on changes in volume of stored product. Make sure that any tank test is performed according to the National Fire Protection Association (NFPA) 329, "Precision Test" requirements (summarized in Exhibit 1.4-10) and by a qualified precision testing company. A comparison of these methods is provided in Exhibit 1.4-11.⁹ Nonvolumetric leak tests include a variety of tank test methods, such as acoustical monitoring, air tracer systems, or internal tank inspections. Leak tests performed using many of these methods are not accepted by DEC. A list of methods considered unacceptable and the reasons why DEC does not permit their use is provided in Exhibit 1.4-12.

An internal inspection for certain bulk storage tanks may be acceptable as an alternative to tightness testing. Guidance for conducting internal inspections is provided in Exhibit 1.4-13 along with a list of the acceptable methods.

General guidelines to follow when inspecting the exterior of an aboveground storage tank for evidence of a spill include the following:

⁹ *The U.S. EPA has also made extensive studies of leak detection methods for underground storage tank systems. Although EPA makes no recommendations, the Agency's report -- Underground Tank Leak Detection Methods: A State-of-the-Art Review, EPA/600-2-86/001, January 1986 -- is a good review of all the available methods.*

Exhibit 1.4-10

Summary of Precision Tests Requirements

1. **Precision Test** means any test that takes into consideration the temperature coefficient of expansion of the product being tested as related to any temperature change during the test, and is capable of detecting a loss of 0.05 gal (190 ml) per hour (a limiting criterion widely accepted by most authorities).

2. A test chosen from currently available technology to reasonably determine whether an underground liquid storage and handling system is leaking should be used.^a Precision Tests should be performed by qualified technical personnel experienced in the use of the test method and in the interpretation of data produced.

3. The test procedure should measure the amount of liquid lost based upon fundamentally sound principles. It should detect a leak anywhere in the complete underground storage and handling equipment. If the net change exceeds 0.05 gal (190 ml) per hour or equivalent criterion established for the technology employed, a leak is likely to exist, and appropriate corrective action is necessary.

4. The Precision Test should account for all the variables that will affect the determination of the leak rate. Besides equipment accuracy and operator error, factors that may affect the precision of the testing include:^b

- # Temperature;
- # Deformation of the tank or piping;
- # Depth of water table;
- # Entrapped vapor; and
- # Evaporation.

^a See Underground Tank Leak Detection Methods: A State-of-the-Art Review, EPA/600/2-86/001, January 1986, for a detailed review of various tank leak detection methods. Also refer to TOGS Memo 4.1.2 and 6 NYCRR Part 613 requirements.

^b Refer to NFPA 329 for a detailed discussion of the effects of these factors on Precision Tests.

Source: NFPA 329 (1987)

Exhibit 1.4-11

Comparison of Precision Test Methods Accepted by NYSDEC

	Ainlay Tank Tegrity	Horner Ezy-Check	Heath Petro Tite	Hunter Leak Locator	Mooney Test	Tank Auditor
<i>Principle of Operation</i>	-pressure measurement by a coil type manometer, determine product level change in a propane bubbling system	-pressure measurement, determine product level change in an air bubbling system	-pressurize a system by a standpipe -keep the level constant by product adding or removing -measure volume change -product circulation by pump	-"principle of buoyancy" the apparent loss in weight of any object submerged in a liquid is equal to the weight of the displaced volume of liquid	-level change measurement with a dipstick	-"principle of buoyancy"
<i>Claimed Accuracy (gal/hr)</i>	-0.02	-less than 0.01	-less than 0.05	-0.05 even at product level at the center of a tank	-0.02	-0.00001 in fill pipe -0.03 at center of 10.5' diameter tank
<i>Approx. Cost</i>	-\$225/day + exps. (3 tanks/day)	-\$300/tank	-\$75/1000 gal.	-\$500/tank	-\$250/tank	-\$400/tank
<i>Single Tank Prep. for Test</i>	-fill tank evening before	-fill 4 hrs. prior to test (usually test at night)	-fill tank prior to test	-typically fill tank before testing	-fill tank 12-14 hrs. prior to test	-none
<i>Tests Single or Multiple Tanks</i>	-2	-2	-4	-3	-3	-1
<i>Potential for Printed Readout</i>	-no	-yes	-no	-yes	-no	-yes
<i>Tests @ Pressure No Greater Than 5 PSIG</i>	-yes	-yes	-sometimes no	-yes	-yes	-yes
<i>Total Downtime for Testing</i>	-10-12 hrs. (filled night before 1.5 hrs of testing)	-4-6 hrs. (2 hr. wait after fill up, 1 hr. test)	-6-8 hrs.	-3-4 hrs.	-14-16 hrs. (12-14 hr. wait after fill up, 1-2 hr. test)	-1.5-3 hrs.
<i>Requires Empty/Full/Overfilled Tank for Test</i>	-full	-full	-overfilled	-typically full	-full	-typically full

Source: TOGS Memo 4.1.2 (August 16, 1986).

Exhibit 1.4-11

**Comparison of Precision Test Methods Accepted by NYSDEC
(continued)**

	Ainlay Tank Tegrity	Horner Ezy-Check	Heath Petro Tite	Hunter Leak Locator	Mooney Test	Tank Auditor
<i>Temperature Compensation</i>	- 3 temperature sensors - 0.01°F accuracy	- averaging temperature coil - 0.001°F accuracy	- one temperature sensor - 0.003°F accuracy - product circulation	- one temperature sensor at mid-volume - 0.001°F accuracy - 3 sensors at unusual conditions	- 5 temperature sensors - 0.001°F accuracy	- use reference tubs
<i>Ground-water Masking</i>	- may conduct testing when leak is completely masked	- conduct test by standpipe if water table is suspected	- tests by standpipe	- may conduct testing when leak is completely masked	- may conduct testing when leak is completely masked	- the test is performed at two different levels
<i>End Deflection</i>	- overnight wait after fill up - if tank is filled one hour before test, deflection is recognized by evaluation of results	- recognized by tests results evaluation	- stops the end deflection within 2 hours by test results evaluation	- end deflection occurs immediately after fill up - 1.5 hour wait for temperature adjustment	- test 12-14 hours after filling	- test at normal operating conditions or 3-6 hrs. after delivery
<i>Vapor Pockets</i>	- if vapor pocket is recognized, tank top will be excavated and the vapor removed by drilling	- could be released by a float tube - uses standpipe to stabilize vapor pocket	- the presence of vapor pockets is recognized by observing bubbles in the standpipe	- compensate if the pocket is released - not affected during in-tank testing	- no compensation	- not compensated during testing in a filled tank - not applicable during in-tank testing
<i>Evaporation</i>	- uses propane gas to reduce evaporation - short testing intervals	- testing time is short - overnight testing (usually) - could use standpipe	- the graduate top is capped	- compensated by a hollow sensor filled with product	- compensated by using an evaporation cap	- short testing - compensated by temperature probe
<i>Wind</i>	- not compensated	- partially compensated by printed result evaluation	- not affected	- partially compensated	- not compensated	- compensated

Source: TOGS Memo 4.1.2 (August 16, 1986).

Exhibit 1.4-11

**Comparison of Precision Test Methods Accepted by NYSDEC
(continued)**

	Ainlay Tank Tegrity	Horner Ezy-Check	Heath Petro Tite	Hunter Leak Locator	Mooney Test	Tank Auditor
<i>Vibration</i>	- not compensated	- partially compensated by result evaluation or by using a standpipe	- not affected	- partially compensated	- not compensated	- not compensated
<i>Noise</i>	- not affected	- not affected	- not affected	- not affected	- not affected	- not affected
<i>Tank Geometry</i>	- not compensated for temperature compensation - reduced by calibration	- not compensated for temperature compensation	- not compensated for temperature compensation	- not compensated for temperature compensation	- not compensated for temperature compensation	- compensated by calibration
<i>Instrumentation Limitation</i>	- leak rate measurement when volume change is less than 0.06 gal. during test	- no limitation for typical tank testing (4-inch fill pipe)	- no limitation for typical tank testing (4-inch fill pipe)	- sometimes due to tank inclination	- no limitation for typical tank testing (4-inch fill pipe)	- sometimes due to tank inclination
<i>Operator Error</i>	- insignificant	- insignificant	- insignificant	- insignificant	- insignificant	- insignificant
<i>Atmospheric Pressure</i>	- not affected	- not affected	- not affected	- compensated	- not affected	- not affected
<i>Inclined Tank</i>	- by calibration	- by calibration	- by calibration	- by calibration	- by calibration	- by calibration
<i>Power Variation</i>	- not affected	- not affected	- not affected	- not compensated	- affected	- not compensated

Source: TOGS Memo 4.1.2 (August 16, 1986)

Exhibit 1.4-12

Tank Test Methods Currently Unacceptable to NYSDEC

Test results obtained using any of the following methods are considered to be unacceptable to DEC for one or more of the reasons listed below.

- A. The following tank testing methods are unacceptable because they are run only on partially full tanks and, therefore, do not test the entire tank:
- # ARCO HTC Underground Tank Leak Detector; and
 - # Ethyl Tank Sentry.
- B. The following tank testing methods are unacceptable because they are more properly used as monitoring rather than testing methods and/or because they cannot detect leaks as small as 0.05 gallons per hour:
- # Standpipe (Hydrostatic) test;
 - # Pneumatic (Air Pressure) test;
 - # Inventory Reconciliation;
 - # Veeder-Root Tank Level Sensor (TLS); and
 - # Smith and Dennison Helium Test.
- C. The following tank testing methods are unacceptable because they are experimental or not commercially available:
- # Certi-Tek Testing;
 - # Helium Differential Pressure Testing;
 - # PALD-2 Leak Detector;
 - # SRI Laser Beam Leak Detection;
 - # Acoustical Monitoring System (AMS);
 - # Ultrasound, Ultrasonic Leak Detector;
 - # Varian Leak Detector;
 - # Vacutect (Tanknology); and
 - # TRC Rapid Leak Detector.
-

Source: TOGS Memo 4.1.2 (August 16, 1986)

Exhibit 1.4-13

Guidance for Internal Tank Inspections

Internal inspection will be accepted as an alternative to precision tightness tests under the following conditions:

- # Tank size is greater than 50,000 gallons;
- # Tanks are considered "technically impossible to test" in reference to precision test. For example, a tank that is only one half under the ground is susceptible to variations in temperature, and cannot adequately be evaluated by precision testing methods.

Initially, all product and tank bottoms must be removed, and the tank interior cleaned to remove loose scale, corrosion, and residual product. Tank entry is an extremely dangerous procedure and should only be performed by properly trained and equipped personnel. Tanks containing gasoline residues are explosive, and all possible ignition sources should be kept at a safe distance. Positive ventilation and standby personnel should also be provided as additional precautionary measures. Further information on safety precautions is provided by the American Petroleum Institute (API) and National Fire Protection Association (NFPA) publications.*

In some locations and for some types of equipment, adequate inspection consists of visual inspection of the tank shell to detect corrosion, and a more detailed inspection by using one or more of the following methods:

- # Ultrasonic techniques;
- # Acoustic emission techniques;
- # Aural inspection (ballpeen hammer test);
- # Magnetic particle inspection;
- # Liquid penetrant inspection;
- # Fluorescent inspection; or
- # Electromagnetic inspection.

* References for fire and safety precautions: (1) API Publication 2015, Cleaning Petroleum Storage Tanks, 1982; (2) API Publication 2015A, Guide for Controlling the Lead Hazard Associated with Tank Entry and Cleaning, June 1982; (c) NFPA 30, Flammable and Combustible Liquids Code, 1984.

Source: TOGS Memo 4.1.2 (August 16, 1986).

NOTES

- # Discoloration of paint is often an indication of leakage or overfills.
- # Check for gross leaks resulting from corrosion or cracks. Check all fixtures and seams.
- # Check valves, pipe fittings, and hoses for evidence of wear due to high liquid turbulence or velocity changes that stress the system. Leaks are most likely to occur around pipe bends, elbows, tees, and other restrictions (e.g., orifice plates and throttling valves).
- # Check loading and unloading hoses used as flexible connections between vehicles and storage tanks, these are extremely vulnerable to wear and tear.
- # Check product transfer pumps and compressors for deterioration from mechanical wear, erosion, or corrosion. They can also fail because of improper operating conditions; piping stresses; cavitation and foundation deterioration; foundation cracks; uneven settling; missing anchor bolts; faulty pump seals; excessive vibrations and noise; deterioration of insulation; and excessive dirt. A burning odor or smoke may indicate pump and compressor failure.
- # Examine heat exchangers or condensers and inspect the pressure-release valves and bladder-height gauges in vapor control systems.
- # Concrete curbing around the base of the foundation and foundation ringwalls can crack or decay. Concrete pads, base rings, piers, column legs, stands, and any other general support structures should be examined for cracks and splitting. Wooden tank supports should be checked for rotting. Anchor bolts should also be checked for structural integrity and tightness.

Once you have identified the most probable source, your on-site inspection should focus on such questions as the following:

1. If a leak has occurred, has it been stopped?
2. Has the fire department been consulted to determine whether or not a fire hazard or explosive situation exists? Is there any safety hazard? Are vapor exposures significant to workers/residents in nearby buildings through windows, ventilation systems, or subsurface electrical vaults? Is ponded product finding its way into sewer lines and posing a potential explosion hazard?
3. Does ponded product exist in the excavation, on the ground water, or elsewhere in the area?

NOTES

4. Is this site near sensitive land uses (e.g., next to homes, a school)?
5. Are existing pathways of concern apparent (i.e., sewer laterals, utility conduits, nearby wells, surface runoff)?

3. Determining the Site History and Property Ownership

Interviews should be combined with checks of the Petroleum Bulk Storage records searches of the historical records concerning land uses and property ownership over time. The latter can include a review of a historical series of aerial photographs, interviews with a town or local area historian, a search through the tax records and maps, and a search of the property deed recordings. A key question in this regard is how much time should you spend in tracking down people and records in an attempt to document responsibility for a spill (remember, identifying who owns property does not necessarily identify the possible spiller). The answer is, "it depends." Documenting responsibility for the spill is a very important concern -- we want spillers to clean up spills themselves or reimburse the state for funds spent in a State-directed cleanup. These concerns, however, should not outweigh the emphasis you place on your primary concern: protection of human health and the environment. If you believe a spill is serious enough to demand an immediate clean-up effort, then you should concentrate on the cleanup and not spend time documenting ownership and establishing the chain-of-events leading up to the spill. At the same time, there comes a point in each spill response where there will be sufficient time to work on establishing spiller responsibility; it shouldn't be ignored.

Remember that establishing property ownership definitively may prove very difficult for spills in urban settings where properties are often abandoned or change ownership frequently.

4. Determining the Extent of Contamination

A critical consideration in your estimation of the severity of the spill and the urgency and complexity of the clean-up effort will be how much area has been impacted, and who or what might be exposed to the contamination in that area. Determining the horizontal (and, in some cases, vertical) extent of contamination must occur fairly quickly unless you have other information to indicate otherwise. Learning that you have a small, localized spill that has soaked into a few inches of soil versus a free and dissolved product plume stretching towards a municipal well field, for example, would be very important information towards determining how and how fast you must investigate the problem. The latter scenario may mean there is little time to waste (depending upon the velocity of ground-water flow and the influence of the pumping wells) investigating the extent of contamination (i.e., how close to the well field is it?), or that actions must be taken quickly to buy the time to investigate the situation carefully (e.g., stop pumping the municipal wells closest to the source).

NOTES

Site investigation methods for determining the extent of contamination vary to some degree for surface, subsurface, and structural contamination due to a spill. Investigatory methods for each of these contamination types are covered below.

a. Determining the Extent of a Surface Spill

Contamination on the ground or water surface may not necessarily originate from an obvious surface spill (therefore, an investigation of a surface spill may actually involve investigating a subsurface spill). For example, a subsurface spill can contaminate surface waters and soil after product has migrated through the soil and via ground water to emerge as a surface seep (see Determining the Extent of a Subsurface Spill on Page 40). However, it is usually easier to determine the extent of surface spill than it is to determine the extent of a subsurface spill because the contamination is more easily seen or measured, especially for a liquid or solid product spill. A surface spill of a gaseous product is more difficult to track without access to sophisticated monitoring stations unless there is contaminant deposition from the vapor cloud that can be measured in the surface soil and/or water.

The extent of contamination from a surface spill depends on the physical properties of the released product, the amount and duration of the release, and on various site-specific characteristics. The transport of the released product is affected by certain properties: specific gravity, solubility, viscosity, and volatility. The specific gravity of the released product determines whether it will float on or sink into the water. The degree of solubility of the product constituents in water determines how difficult it may be to separate the dissolved contaminant from water. The viscosity of the released product also affects its mobility in the environment. If the spilled product is particularly volatile, a spill may evaporate before it travels any great distance to contaminate soil or water. These properties, together with other site-specific factors, determine how fast the spill may move through the environment.

The effects of soil type on the transport of released product are discussed in the next subsection, Determining the Extent of a Subsurface Spill. Other site-specific characteristics, such as the topography of the spill area, surface drainage patterns, and utility line configurations, also affect the direction and/or pattern of surface contamination. Streams and utility lines provide excellent conduits for transporting the released product. Cracks in the sidewalk in more urban settings also complicate the spread of a surface spill. Assessing the levels of contamination at various spots in a stream, utility system, or water supply source can help define the extent of contamination. Depending upon the size of a spill, a visual survey of the area may be sufficient to track its path, or you may need to consult aerial photographs or topographic maps and other geographic information for the

NOTES

area.¹⁰ Use maps and photographs whenever possible to effectively illustrate the areas (lands, surface waters, and the like) that are known to be contaminated or appear susceptible to contamination. For spills yielding hazardous gases, record the principal wind direction and its speed from data obtainable through local weather stations or airports and use this information to predict how fast and in what likely direction the vapor cloud will migrate.

b. Determining the Extent of a Subsurface Spill

Determining the extent of contamination from a subsurface spill includes examining both **soil contamination** and **ground-water contamination** (free and/or dissolved product). Subsurface spills will always contaminate some area of soil. How much soil becomes contaminated is determined by how quickly the spill was detected, how much was spilled (a very large leak can be detected very quickly and a small leak that isn't detected can amount to a large spill over time), and how easily the material moves through soil. Whether ground water also becomes contaminated by a subsurface spill depends on these same factors plus the depth to ground water at the site. An underground tank located near or within the seasonal high water table, if it leaks, will contaminate ground water. An intervening clay layer may act to retard contaminant migration.¹¹

However, if contaminated soil is not removed or otherwise remediated, it can act as a continuing source of free product and dissolved contaminants as rainwater leaches contaminants deeper into the soil or as a function of changes in water table elevation. As a general rule (based on ground-water modeling studies), the greater the amount of contaminated soil, independent of the contaminant concentrations, the greater the risk of ground-water contamination and the higher the expected dissolved contaminant concentrations.

Depending upon the size and duration of the spill, investigating the extent of contamination from a subsurface spill can be both costly and time consuming. Before digging monitoring pits or installing soil borings and ground-water monitoring wells, make as much use as possible of water quality data from existing water supply (or other) wells and from surface water (which is usually hydraulically connected to ground water) located in the vicinity of the spill. These data provide information on the contaminant concentrations to which people are exposed and can give you an idea of how far ground-water contamination may have spread.

¹⁰ Common sources for such maps and photos include: United States Geological Survey (USGS), the Soil Conservation District Offices, the engineering or architectural firms that designed or built nearby structures, local surveyors, the town or city department of public works, libraries, and stationery stores.

¹¹ High hydrocarbon concentrations in a deep clay layer could be regarded as evidence that the downward migration of the contaminants is restricted. Alternatively, this clay layer could be regarded as a long-term source of contaminants. This example illustrates that the same observation can be interpreted very differently.

NOTES

Access available geologic information to determine soil types, soil composition, type of bedrock and depth to bedrock, and depth to ground water. This literature search can determine, for example, that the site is underlain by shallow, fractured bedrock, or that there are sand layers in the near-surface and largely clayey soils. In the former instance, attempting to track contamination in the bedrock ground water would be exceedingly difficult given all the possible migration paths the contamination can take. It is conceivable that many monitoring wells could be drilled in this environment and not intercept the contamination at all. Accordingly, one might not drill wells at all, but might dig a trench down and into bedrock as a more effective monitoring and recovery technique since the trench will intercept a greater number of flow paths.

In the latter instance, you would want to locate monitoring wells in these channel sands as the contamination is likely to preferentially flow along these more permeable pathways. Again, it is conceivable that, lacking this knowledge, one could drill monitoring wells in this environment and completely miss the migrating subsurface contamination.

One way to minimize the "hit or miss" aspect of a well drilling program is to utilize techniques like soil gas monitoring and terrain conductivity. These techniques are essentially screening methods that can be used to quickly assess an area to generate data on the extent of subsurface contamination sufficient to guide where confirmatory sampling (soil borings and monitoring wells) should be conducted. This latter point is important. Soil gas and/or geophysical surveys **alone** cannot conclusively map the extent of subsurface contamination.¹² Each must be used in combination with a confirmatory sampling program, that is, it is still necessary to drill soil borings and/or sample ground water for contaminants. The benefit to using these techniques, however, is that they generate more information that you can use to guide your selection of drilling locations. The result can be that potentially fewer borings/wells are installed in comparison to a drilling program based upon, for example, moving out from a source in ever-larger concentric circles or squares.

Soil Properties

Soil type and composition directly affects the permeability of the soil to the released product. Liquids or vapors enter, accumulate, or flow through soil or rock in the void or pore spaces between the particles that make up the soil or rock. The size of the voids in soil vary from large (gravel), to small (sand and topsoil), to essentially zero (dense clay). This variation

¹² *These methods are also subject to interferences. Geophysical methods, for example, are sensitive to sources of electromagnetic radiation (e.g., overhead power lines). Other volatile materials within the subsurface can present interferences for soil gas methods. Methane gas is one such example, particularly in municipal landfills, in wetland areas, or in any area of extensive fill.*

in void size and the interconnections between the void spaces translates in differences in permeability to product (or water or water and product) that can range from several feet per minute in gravel to one foot per day in shale or sandstone. Hydraulic conductivity is an index by which to measure the permeability of soil or rock. Exhibit 1.4-14 provides a quick reference to the range in hydraulic conductivity for selected soils and rocks for estimating potential flow rate.¹³

The flow pattern of a subsurface spill is more difficult to predict in heterogeneous soils or those with irregular patterns of fractured bedrock (Exhibit 1.4-15). A subsurface spill mass that encounters an impermeable clay layer will accumulate and then spread laterally until it can once again migrate downward through more permeable earth materials. As noted earlier, a fractured bedrock flow system often makes it very difficult to predict the direction of subsurface flow. Similarly, areas where fill materials have been deposited (e.g., along shorelines or in wetland areas) may exhibit complicated flow patterns.

Not all of the subsurface spill will reach ground water, however. Significant amounts of the product will remain trapped in the void spaces in the earth materials to remain in what is known as the residual saturation state (see Part 1, Section 6.7, Ground-Water Remediation). The type of soil and the depth to ground water will directly affect the amount of released product that remains in the residual saturation state. In addition, as the void spaces fill with water (i.e., become more saturated), there is less pore space left for the continued downward migration of product. Consequently, the spill mass begins to spread along the water table (see Part 1, Section 6.7, Ground-Water Remediation). If the product has a specific gravity less than water (water has a specific gravity of one), the result is a free product layer although some of the more soluble product constituents will dissolve into the aquifer. If the product has a specific gravity greater than water, the product mass will sink into and, perhaps, through the aquifer until it reaches a confining layer. Again, the more soluble constituents in this "sinking product" will dissolve into the aquifer.

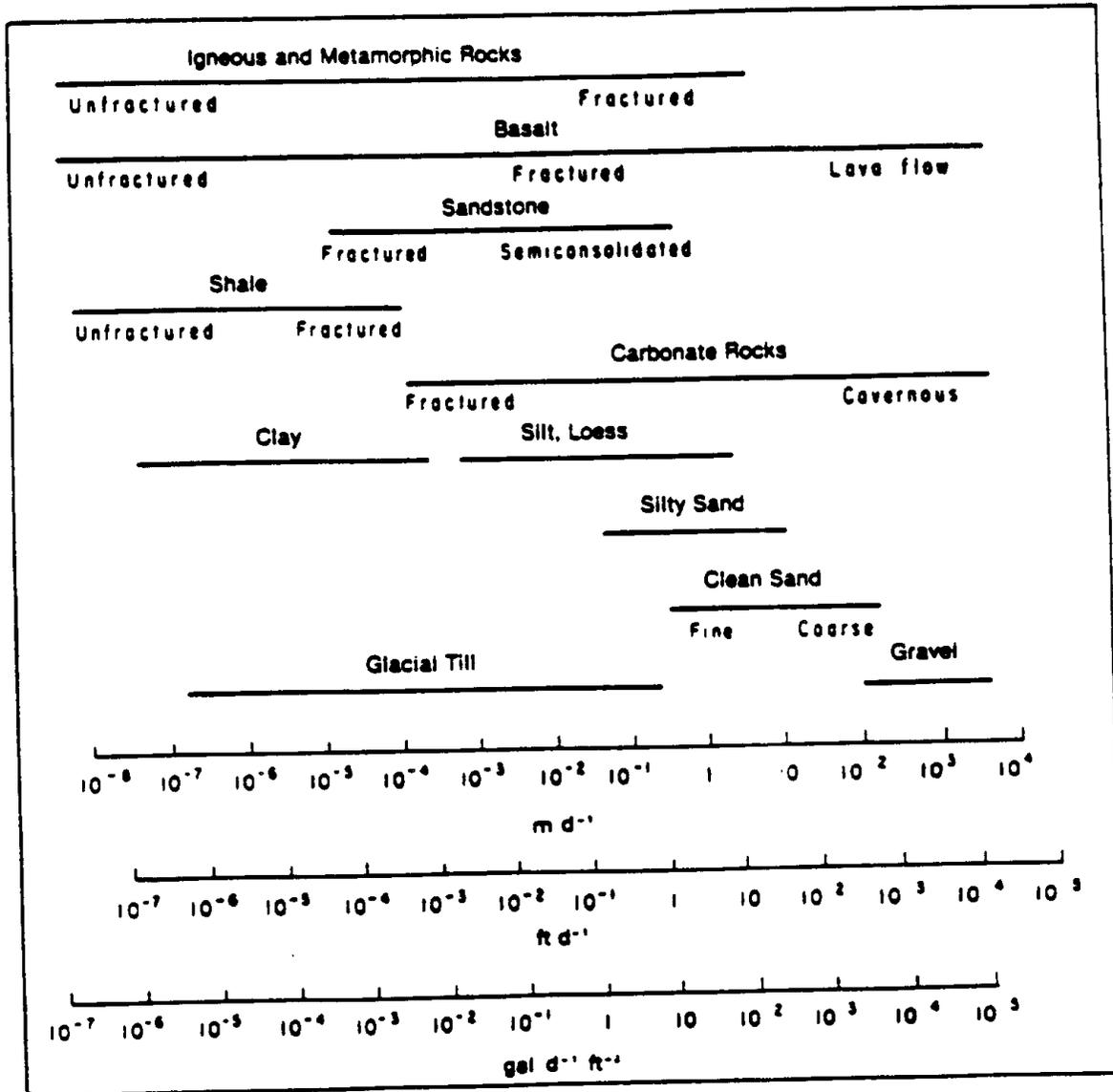
¹³ The hydraulic conductivity, K , is defined by

$$K = \frac{v}{i}$$

where v is the flow rate, and i is the hydraulic gradient (defined as the drop in pressure head per unit distance between two points in the soil). K is generally determined in the laboratory under controlled flow conditions when v and i are known. Alternately, the flow rate, v , can be estimated from field measurements for i and a laboratory-determined value for K .

Exhibit 1.4-14

Hydraulic Conductivity of Selected Soils and Rocks

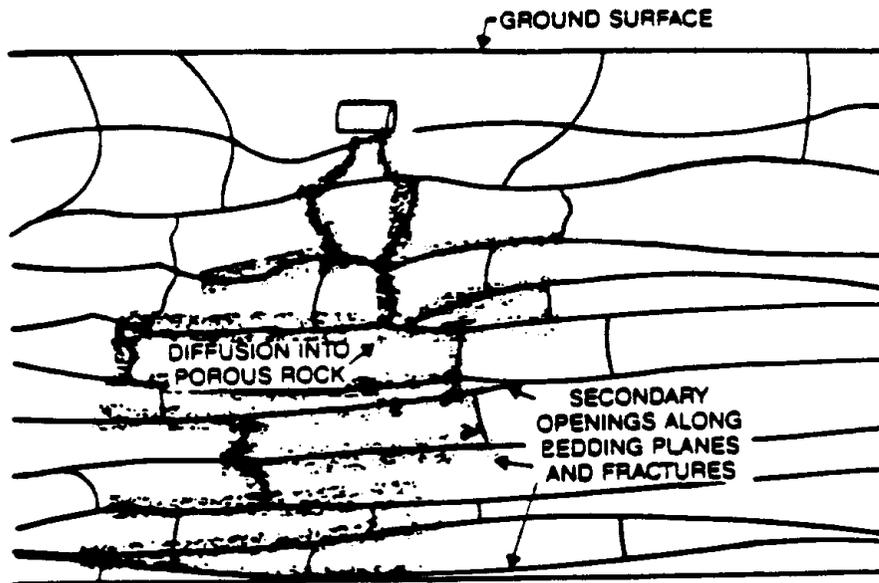


Source: United States Geological Survey (1982).

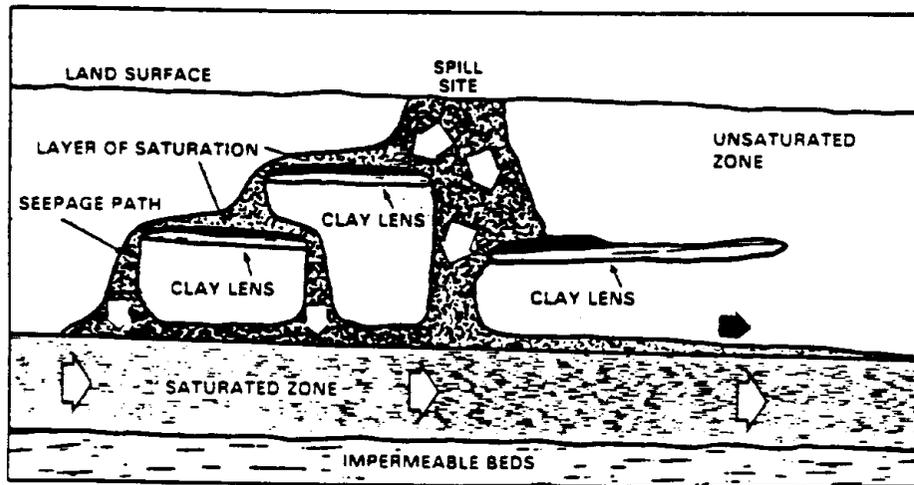
Exhibit 1.4-15

Heterogeneities of Soil and Rock

(a) Migration of Free Product in Fractured Rocks



(b) Effect of Clay Lens in Soil



Source: (a) [1], (b) [2].

NOTES

Information on soil characteristics is generally available from the state geological survey office, the U.S. Geological Survey, the Soil Conservation Service, area universities, and from samples you can take when you install monitoring pits, soil borings, monitoring wells, recovery wells, interceptor trenches, or soil ventilation systems. A local public works department can also be a source of valuable information concerning the types of materials encountered in excavations, water table depths, and probable direction of flow. A geologist should log all borings. Be careful in making hasty assumptions and inferences about the soil characteristics over a large area based on only a few soil samples as soils are rarely uniform over an extensive area. Building foundations, sewer lines, water mains, and utility conduits add to the heterogeneity of the subsurface materials and will often provide preferential flow paths for contaminant migration.

Hydrogeology

Having the following hydrogeologic information is essential for assessing the extent of subsurface contamination:

- # **Minimum depth from ground surface to the water table.** Depth to ground water, or the water table, directly affects the probability of ground-water contamination from a spill. For example, with increased depth to ground water, an increased amount of the spilled product can be retained in the void spaces. It is possible for all of the product to be adsorbed in these spaces before it reaches the water table. Note, however, that this reservoir of product will represent a continuing source of contamination over time to the point that eventually some of the contamination will reach ground water.

- # **Slope of the water table.** The slope (gradient) of the water table determines in which direction free product and dissolved material will migrate. The slope of water table can be determined by comparing the water levels at three or more monitoring wells, and often is approximated by the ground surface topography and slope. Ground water and free product will flow from higher to lower elevations.

- # **Seasonal fluctuations of the water table.** A typical water table will fluctuate up and down in response to seasonal changes, variations in rainfall, and in response to ground-water usage. A rising water table will carry free petroleum product upward (possibly causing nuisance conditions, like free product or vapors in a basement, to reappear), and will trap some product below the water table. A falling water table will leave behind residual product in the void spaces (see Exhibit 1.4-16). The result is a greater distribution of product in the subsurface and product trapped

NOTES

below the water table will generally not be recoverable unless the water table drops precipitously (see Part 1, Section 6.7, Ground-Water Remediation).

- # **Hydraulic connection between the ground-water system and nearby surface water.** Ground water is often hydraulically connected to surface water; that is, ground water contributes to the surface water flow. A subsurface spill can migrate in ground water to appear later in the surface water or as a seep as shown in Exhibit 1.4-17.

Other Site-Specific Characteristics

As noted above, the presence of sewer or utility lines at a spill site can provide for preferential flow paths (i.e., along the higher permeability backfill material) for liquid and vapor contamination to migrate in directions not expected on the basis of the local geology or hydrogeology. Locating these underground utilities is important for another reason as well: you will need to know the location of all the underground utilities before beginning a drilling program. The presence of existing pumping wells in the vicinity will also influence ground-water flow patterns potentially in directions not expected on the basis of the surface topography. The records on these wells may also provide important geological and hydrogeological information for your investigation such as stratigraphic data and the depth to ground water.

Field Monitoring

Much of the site investigation to determine the extent of a subsurface spill will involve the collecting of data from the sampling of subsurface soils and ground water. Designing a monitoring program involves two related considerations. Select monitoring locations to learn as much as possible about subsurface conditions and to establish the vertical and horizontal extent of contamination. In addition, some monitoring locations should be located to help measure the progress of remedial measures taken at the site.

Exhibit 1.4-16
VERTICAL EXPANSION OF CONTAMINATED SOIL ZONE
BY FLUCTUATING WATER TABLE

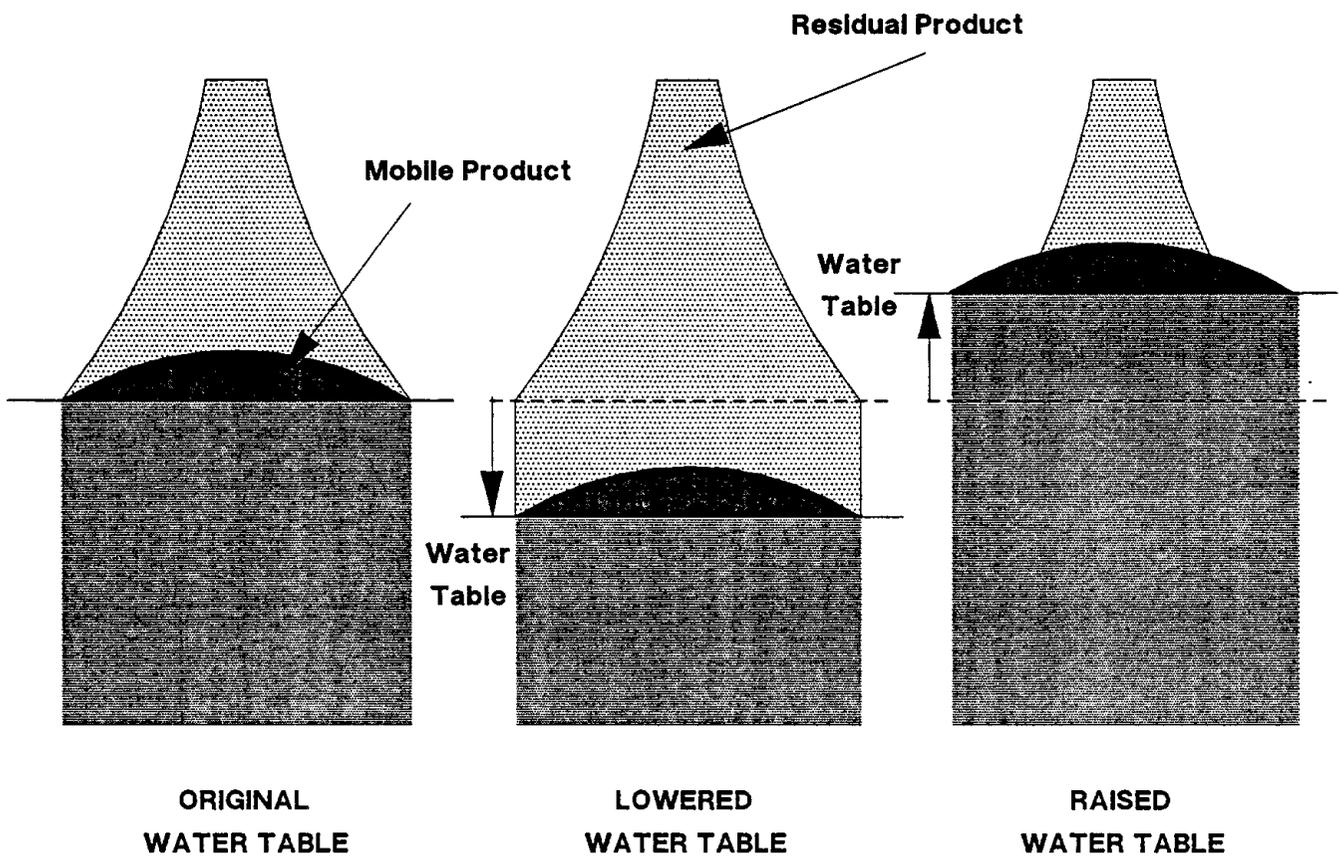
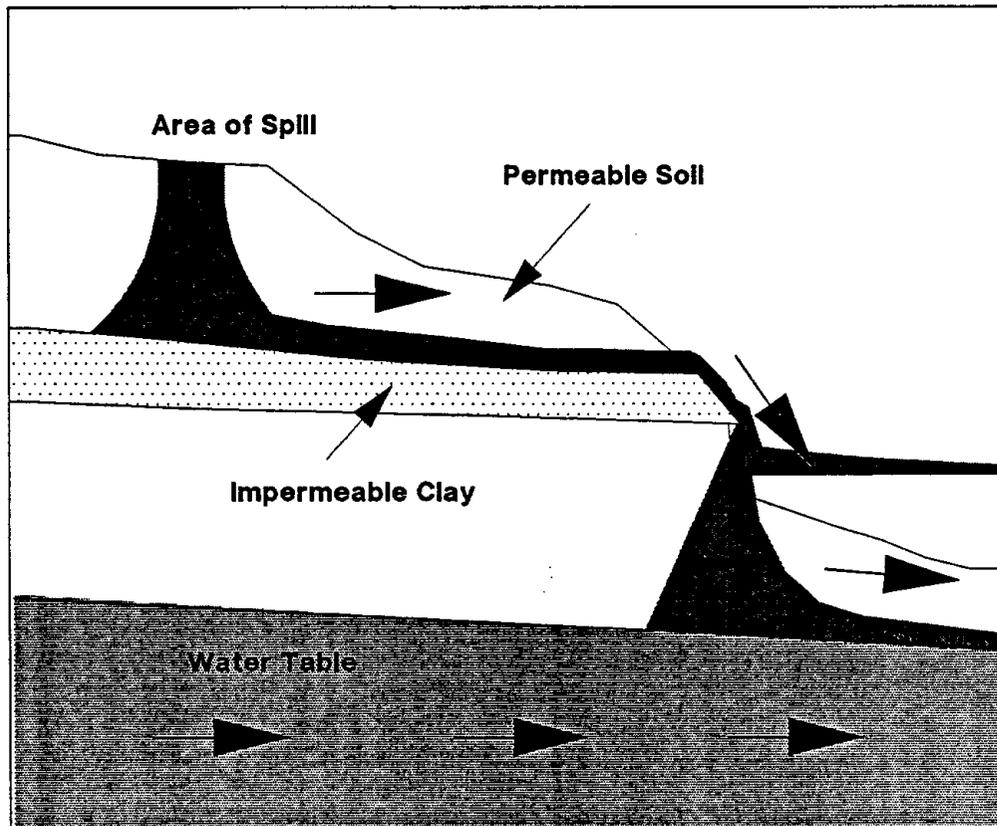


Exhibit 1.4-17
POSSIBLE MIGRATION OF PRODUCT TO OUTCROP,
FOLLOWED BY SURFACE CONTAMINATION



NOTES

Both monitoring pits or trenches and monitoring wells are used. Monitoring pits/trenches work well when bedrock and ground water are shallow (i.e., less than 15 feet). A monitoring pit/trench can reveal considerable information about the stratigraphic soil layers between ground surface and bedrock. In addition, since the pit/trench intercepts a large area of flow paths or channels, it is possible to have them double as effective product collection and recovery systems in subsurface environments, such as fractured, near-surface bedrock, where intercepting the contaminant flow with a well would have been a "hit or miss" proposition. The use of monitoring pits/trenches is limited, however, by the depth to which pits/trenches can be dug without the use of special equipment. Using a backhoe, this maximum depth is about 15 feet, and as the depth increases, more consideration must be given to shoring the sides of the trench to prevent collapse. In addition, trenches are difficult to keep open in very wet soils where the walls will tend to slough in.

If the contamination is known to have reached depths greater than 15 feet or so, you will need to install soil borings and monitoring wells to sample soils at depth and sample ground-water quality. Various drilling methods are used depending upon the drilling depth and the nature of the geologic materials that must be passed through (see Exhibits 1.4-18 and 1.4-19). Caution should be exercised in drilling through contaminated zones and confining layers so as to not provide a route for contaminants to migrate vertically. Any well drilled through a contaminated zone or confining layers should be adequately sealed. It may be prudent not to drill through confining layers in certain areas, or to drill only partly into them to determine their effectiveness in retarding the vertical movement of contaminants. Before drilling also contact utility companies ("Miss Utility") so that buried pipes and cables can be located. A minimum of three borings, taken below or next to the underground tank or the area previously occupied by the tank, should be used for soil sampling to check for lateral and vertical movement of contaminants. Additional borings may be necessary in some locations, particularly where the associated piping is suspected of leaking. Soil samples should be taken for laboratory analysis of total

Exhibit 1.4-18 Basic Well Drilling Methods

Drill Type ^a	Normal Diameter Hole	Maximum Depth	Average Time Per Hole	Normal Expense	Advantages	Disadvantages
1 Mud Rotary Air Rotary	4"-20"	Unlimited	Fast	Expensive	<ol style="list-style-type: none"> 1. Good for deep holes 2. Can be used in soils and relatively soft rock 3. Wide availability 4. Controls caving 	<ol style="list-style-type: none"> 1. Need to use drilling fluid 2. Potential bore hole damage from drilling fluid.
2 Solid Stem Auger	4"-8"	100-150 ft.	Fast under suitable soil conditions	Inexpensive to moderate	<ol style="list-style-type: none"> 1. Wide availability 2. Very mobile 3. Can obtain dry soil samples while drilling 	<ol style="list-style-type: none"> 1. Difficult to set casing in unsuitable soils (caving) 2. Cannot penetrate large stones, boulders, or bedrock 3. Normally cannot be used to install recovery wells 4. Difficult to obtain undifferentiated soil samples
3 Hollow Stem Auger	4"-12"	100-150 ft.	Fast under suitable soil conditions	Inexpensive to moderate	<ol style="list-style-type: none"> 1. Good for sandy soil 2. Can set casing thru hollow stem 3. Very mobile 4. Can obtain dry soil samples and split spoon samples 5. Controls caving 	<ol style="list-style-type: none"> 1. Casing diameter normally limited to 4"-6" 2. Cannot penetrate boulders or bedrock 3. Limited avail- ability

**Exhibit 1.4-18
Basic Well Drilling Methods
(continued)**

Drill Type ^a	Normal Diameter Hole	Maximum Depth	Average Time Per Hole	Normal Expense	Advantages	Disadvantages
4 Kelley Auger	8"-48"	100 ft.	Fast	Moderate to expensive	<ol style="list-style-type: none"> 1. Can install large-diam. recovery wells 2. Drills holes with minimum soil wall disturbance or contamination 3. Can obtain good disturbed soil samples 	<ol style="list-style-type: none"> 1 Large equipment 2 Seldom available in rural areas 3 May require casing while drilling 4 Does not work in wet sandy soils
5 Bucket Auger	12"-72"	90 ft.	Fast	Moderate to expensive	<ol style="list-style-type: none"> 1. Can obtain good disturbed soil samples 2. Can install large-diam. recovery wells 3. Good in sandy soils 	<ol style="list-style-type: none"> 1 Typically requires drilling fluid 2 Normally very large operating area required
6 Cable Tools	4"-16"	Unlimited	Slow	Inexpensive to moderate	<ol style="list-style-type: none"> 1. Wide availability 2. Can be used in soil or rock 	<ol style="list-style-type: none"> 1 Slower than other methods 2 Hole often crooked 3 May require casing while drilling

^aSee Part 3, Section 1, for a description of these drilling methods.

**Exhibit 1.4-18
Basic Well Drilling Methods
(continued)**

Drill Type^a	Normal Diameter Hole	Maximum Depth	Average Time Per Hole	Normal Expense	Advantages	Disadvantages
7. Air Hammer	4"-12"	Unlimited	Fast	Expensive	Fast penetration in consolidated rock	<ol style="list-style-type: none"> 1. Inefficient in unconsolidated soil 2. Geophysical logs not available 3. Control of dust/air release 4. Excessive water inflow will limit use
8. Casing Driving (well point)	2"-24"	60 ft.	Slow to moderate	Inexpensive	<ol style="list-style-type: none"> 1. Wide availability 2. Very portable 	<ol style="list-style-type: none"> 1. Limited to unconsolidated soil; cannot penetrate large boulders or bedrock 2. No soil samples 3. Generally inefficient method to install recovery well
9. Dug Wells	Unlimited	10-20 ft.	Fast	Inexpensive	<ol style="list-style-type: none"> 1. Wide availability 2. Very large-diam. hole easily available 	<ol style="list-style-type: none"> 1. Caving can be severe problem 2. Limited depth 3. Greater explosive hazard during excavating into hydrocarbons
10. Reverse Rotary	4"-36"	Unlimited	Fast	Expensive	<ol style="list-style-type: none"> 1. Same as rotary 2. Good in loose, sandy soil 	<ol style="list-style-type: none"> 1. Same as rotary
11. Reverse Air	4"-50"	Unlimited	Fast	Expensive	<ol style="list-style-type: none"> 1. Good for large-diameter holes 2. Less drilling fluid required 	<ol style="list-style-type: none"> 1. Need dual-walled drilling pipe 2. Increased drill pipe handling
12. Jetting	3"-12"	100 ft.	Fast	Moderate	Good in loose sand	Need to use water as drilling fluid

Source: [2]

Exhibit 1.4-19
Relative Performance of Different Drilling Methods
in Various Types of Geologic Formations

Type of Formation	Cable Tool	Direct Rotary (with fluids)	Direct Rotary (with air)	Direct Rotary (Down-the-hole air hammer)	Direct Rotary (Drill-through casing hammer)	Reverse Rotary (with fluids)	Reverse Rotary (Dual Wall)	Hydraulic Percussion	Jetting	Driven	Auger
Dune Sand	2	5	NR ^a	NR	6	5 ^b	6	5	5	3	5
Loose sand and gravel	2	5	NR	NR	6	5 ^b	6	5	5	3	5
Quicksand	2	5	NR	NR	6	5 ^b	6	5	5	NR	1
Loose boulders in alluvial fans or glacial drift	3-2	2-1	NR	NR	5	2-1	4	1	1	NR	1
Clay and silt	3	5	NR	NR	5	5	5	3	3	NR	3
Firm shale	5	5	NR	NR	5	5	5	3	NR	NR	2
Sticky shale	3	5	NR	NR	5	3	5	3	NR	NR	2
Brittle shale	5	5	NR	NR	5	5	5	3	NR	NR	NR
Sandstone--poorly cemented	3	4	NR	NR	NR	4	5	4	NR	NR	NR
Sandstone--well cemented	3	3	5	NR	NR	3	5	3	NR	NR	NR
Chert nodules	5	3	3	NR	NR	3	3	5	NR	NR	NR
Limestone	5	5	5	6	NR	5	5	5	NR	NR	NR
Limestone with chert nodule	5	3	5	6	NR	3	3	5	NR	NR	NR
Limestone with small cracks or fractures	5	3	5	6	NR	2	5	5	NR	NR	NR
Limestone, cavernous	5	3-1	2	5	NR	1	5	1	NR	NR	NR
Dolomite	5	5	5	6	NR	5	5	5	NR	NR	NR
Basalts, thin layers sedimentary rocks	5	3	5	6	NR	3	5	5	NR	NR	NR
Basalts--thick layers	3	3	4	5	NR	3	4	3	NR	NR	NR
Basalts--highly fractured (lost circulation zones)	3	1	3	3	NR	1	4	1	NR	NR	NR
Metamorphic rocks	3	3	4	5	NR	3	4	3	NR	NR	NR
Granite	3	3	5	5	NR	3	4	3	NR	NR	NR

Rate of penetration: 1 = impossible; 2 = difficult; 3 = slow; 4 = medium; 5 = rapid; 6 = very rapid.

aNR = not recommended.

bAssuming sufficient hydrostatic pressure is available to contain active sand (under high confining pressures)

Source: [3]

NOTES

petroleum hydrocarbons (TPH) and benzene, toluene, ethylbenzene, and total xylenes (BTEX). Sampling for methyl-tertiary butyl ether (MTBE) may also be appropriate as it is quite soluble in water and may be present at the leading edge of a migrating contaminant plume. If the tank is being closed in place, the top of the tank should be exposed. Three (3) samples should be taken, two in the area where the tank and piping meet and the other at the opposite end of the tank (unless exposing the top of the tank reveals other areas where leakage appears likely. If the tank is being or has been removed, soil samples should be taken one to two feet below the bottom of the excavation at likely leak locations, and should be taken as soon as possible after the tank is removed.¹⁴ These samples should be taken from the excavation (as opposed to being taken from locations next to the excavation) for each tank suspected to have leaked. Likely leak locations include: areas around the tank and piping, or where they used to be; areas around the tank or piping, or where they used to be, that look.

In completing each boring, take split-spoon samples starting at ground surface and then at least every five feet thereafter until ground water is encountered or until auger refusal. If a dissimilar layer of soil is found to exist entirely between the five-foot sampling intervals, obtain a sample from this layer. Sampling protocols are provided in Attachment 1.4-4 to this section. A geologist should log each boring.

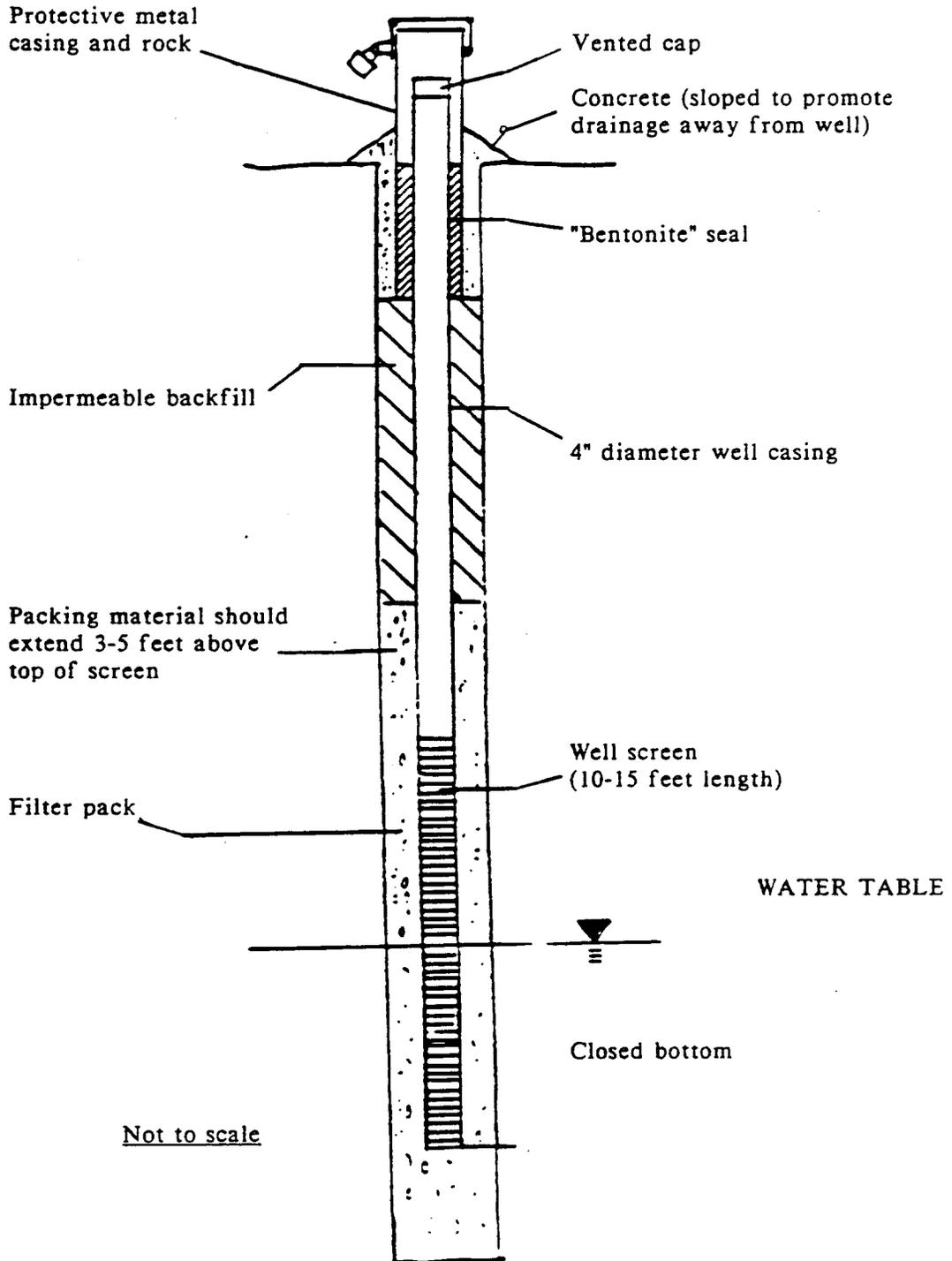
The components of a typical monitoring well are illustrated in Exhibit 1.4-20, and DEC specifications for installing monitoring wells are listed in Exhibit 1.4-21. Two important considerations in well design are (1) the chemical compatibility between the spilled material and the well construction materials, and (2) the wettability and size of the well screen.

Exhibit 1.4-22 shows the chemical compatibility between petroleum products and certain types of well casings and screens. Polyvinylchloride (PVC) screens are the mostly frequently used because of the low cost of materials and installation. The probability that a PVC screen will dissolve under field conditions is low, but will depend upon the concentration of the petroleum product in the ground water surrounding the well and the length of the

¹⁴*It may or may not be safe to enter the excavation to obtain these samples due to the possibility of vapor hazards or collapse of the excavation walls. If it is not safe to enter the excavation to obtain the sample with a trowel or hand auger, these samples may be obtained from a backhoe bucket. Accuracy is improved by disturbing the soil as little as possible so as to not cause the release of volatile contaminants.*

Exhibit 1.4-20

Typical Monitoring Well



Source: NYSDEC TOGS 4.1.1 (1987).

Exhibit 1.4-21

Specifications of Ground-Water Monitoring Wells

1. All wells are to have a nominal four (4) inch diameter.
 2. Boring logs shall be recorded for each boring. Samples shall be taken from each soil layer encountered or, at a maximum, at five (5) foot intervals to obtain a general description of the underlying soils.
 3. Wells must be installed plumb and straight.
 4. Flush-threaded joints must be used to avoid contamination of well by glued joints.
 5. Well screens must be machine slotted and of sufficient length and placement to accommodate seasonal variations in the water table. (Length will generally be 10' to 15' with the mean water table in the middle of the screen.)
 6. The filter pack must be compatible with the soil around the screened portion of the well and with the screen opening. It must extend approximately one foot below the screen and three-to-five feet above the screen.
 7. The well must be sealed with an impermeable material between the casing and the bore hole and capped with concrete or other suitable material to prevent contamination from the surface.
 8. The well must be sufficiently developed to ensure that samples will accurately represent the condition of the ground water.
 9. Survey well elevations to a known datum point.
 10. The tops of the wells must be enclosed by a protective metal casing and locked.
 11. All wells must be marked clearly as monitoring wells.
-

Source: NYSDEC TOGS 4.1.1 (1987)

Exhibit 1.4-22

**Chemical Compatibility Between Selected Well Casing and Screen Materials
and Petroleum Products**

	<u>Stainless Steel</u>			Bronze	Cyclac (ABS)	Kynar	Polypropylene	<u>Polyvinylchloride</u>		Teflon
	316	304	440					PVC		
<i>Benzene</i>	<i>B</i>	<i>B</i>	<i>B</i>	<i>A</i>	<i>D</i>	<i>A</i>	<i>C</i>		<i>C</i>	<i>A</i>
<i>Hexane</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	-	<i>A</i>	<i>B</i>		<i>B</i>	<i>A</i>
<i>Toluene</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>D</i>	<i>A</i>	<i>C</i>		<i>D</i>	<i>A</i>
<i>Xylene</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>D</i>	<i>A</i>	<i>C</i>		<i>D</i>	<i>A</i>
<i>Naptha</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>B</i>	<i>D</i>	<i>A</i>	<i>C</i>		<i>C</i>	<i>A</i>
<i>Gasoline</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>D</i>	<i>A</i>	<i>C</i>		<i>C</i>	<i>A</i>
<i>Turpentine</i>	<i>A</i>	<i>A</i>	<i>B</i>	<i>C</i>	-	<i>A</i>	<i>B</i>		<i>B</i>	<i>A</i>
<i>Kerosene</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>D</i>	<i>A</i>	<i>A</i>		<i>A</i>	<i>A</i>
<i>Jet Fuel</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	-	<i>A</i>	<i>A</i>		<i>A</i>	<i>A</i>
<i>Diesel Fuel</i>	<i>A</i>	<i>A</i>	-	<i>A</i>	-	<i>A</i>	<i>A</i>		<i>A</i>	<i>A</i>
<i>Fuel Oils</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>D</i>	<i>A</i>	<i>C</i>		<i>A</i>	<i>A</i>
<i>Lube Oil</i>	<i>A</i>	<i>A</i>	<i>A</i>	<i>A</i>	-	<i>A</i>	<i>A</i>		<i>B</i>	<i>A</i>
<i>Creosols</i>	<i>A</i>	<i>A</i>	-	<i>C</i>	<i>D</i>	<i>A</i>	<i>D</i>		<i>D</i>	-
<i>Asphalt</i>	<i>A</i>	<i>B</i>	<i>B</i>	<i>A</i>	-	<i>A</i>	<i>B</i>		<i>A</i>	<i>A</i>

A = No Effect B = Minor Effect C = Moderate Effect D = Severe Effect

Source: Cole Parmer (1987)

NOTES

monitoring period. Stainless steel is better suited to more corrosive environments for long-term monitoring, but is about three times more costly than PVC. Teflon[®] is even more durable than stainless steel, but its use is generally limited to severe conditions because of its higher cost.

Wettability is a term used to describe the affinity of a liquid to a solid surface. The relative wettabilities of water and the spilled material to the well screen affects the amount of material entering the well. Wettability may not be an important concern when the released material is dissolved in ground water; on the other hand, if the spilled material does not mix with water (e.g., petroleum), the samples collected from the monitoring well may not adequately represent the conditions of the area surrounding the well. Additional guidance on well construction materials and design is provided in Part 1, Section 6.7, Ground-Water Remediation.

Ground-water elevations are best determined by short-screened (one to five feet) piezometers. More broadly screened ground-water monitoring wells are used to determine gradient, but cannot be used to determine the vertical components of the gradient. Well screens must be machine slotted and of sufficient length and placement to accommodate seasonal variations in the water table. Generally, the screen will need to extend five feet above the high water table elevation (i.e., the entire screen is ten to fifteen feet long) in order to ensure that any floating product will flow freely into the well.

The actual placement of monitoring wells and the number required are dependent on spill- and site-specific information. A minimum of three wells is needed to establish ground-water flow direction.¹⁵ If the water table surface is irregular or the vertical components of flow are significant, a minimum of four wells will be needed. At least one well should be located hydraulically upgradient of the spill source to establish background ground-water quality. A general rule-of-thumb is that as the heterogeneity of the subsurface environment increases, the number of wells should increase, and their positioning should reflect what is known about the subsurface geology. Typically, more wells will be placed on the downgradient side of the spill source for potential contamination. Wells arranged in the configuration of a rectangle or equilateral triangle improve the chance that a well is positioned correctly to obtain a downgradient sample.

¹⁵ *Determining ground-water velocity requires conducting slug tests to estimate hydraulic conductivity, and physical soil tests to estimate porosity may be needed. Slug tests consist of a sudden introduction of a known volume of water (or a cylinder of known volume) and then measuring the time it takes for the water level in the well to stabilize. A bail test is similar except a known volume of water is removed.*

NOTES

In guidance issued on special ground-water protection conditions for major onshore petroleum facilities, NYSDEC specifies these monitoring well locational and design requirements:

- # Major facilities (except those facilities or portions thereof storing No. 6 fuel oil or heavier oils) shall install ground-water monitoring wells outside of their secondary containment systems. If it is impractical to install wells outside the containment system, these wells may be installed inside or on the dike walls if: (a) their wells casings extend at least three feet above the ground (or to a height to prevent product from entering the well in event of a spill); (b) the wells are sealed to prevent product flow down around the casing in the event of a spill; and (c) written approval from NYSDEC is obtained;
- # At least one well must be installed hydraulically upgradient of the facility to be representative of the ambient ground-water quality in the uppermost aquifer only and not affected by the facility; and
- # At least three wells must be installed hydraulically downgradient of the facility to detect ground-water contamination in the uppermost aquifer only.

Well Development and Sampling

Each installed well must be developed; that is, the well must be purged of drilling fluids and sediment that may have moved through the filter pack and well screen. Otherwise, the presence of these fluids and sediment may restrict the flow of water and product from the aquifer materials into the well.

Well development is accomplished by cyclic removal of water from the well using a pump or a bailer. Air-lift and diaphragm pumps are used for well development when there is an expectation that sand will be withdrawn with water; this sand would damage a centrifugal pump. A surge block may also be used for well development. A rod attached to the surge block is used to manipulate the block up and down inside the well; this piston action forces water and sediment back and forth through the screen and filter pack.

Development of the well continues until there is no sediment in the removed water or until there seems to be no further improvement in water quality. Make note of the well water levels, and the clarity, color, and odor of the development water.¹⁶ The total volume of

¹⁶ There are instruments that can measure water turbidity in water. A nephelometer is one such instrument that measures the amount of light transmitted through and reflected by particles in a water sample. A nephelometric turbidity unit (N.T.U.) guideline of less than 5 units has been applied to judging the adequacy of well development activities.

NOTES

water and any product removed during development should be recorded. Development water must be managed in compliance with local, state, and federal regulations.

Before sampling a well (monitoring well or supply well), first measure the water level and product level, if product is present. It is then necessary to purge the well of the standing water in order to obtain a "representative" ground-water sample. Usually, three to five full volumes of standing well water will have to be purged, but continue purging any well capable of a sustained yield until there is 10 percent or less variability in three consecutive measurements of pH, temperature, and specific conductance. This is done by setting the pump intake just beneath the water surface and pumping at a low enough rate to keep the pump below the water surface. If a well is not capable of producing a sustained yield, purge the well completely and allow the water level to recover to 60 to 80 percent of the original level before taking a sample. It will be necessary to follow the water level down with the pump intake as the well is purged.

There are different kinds of equipment available for use in purging wells. The type of equipment is selected based upon the size of the well casing and the depth of water in the well. Equipment recommendations are provided in Exhibit 1.4-23. Avoid using air-lift equipment if product is present in the well as free product and vapor will be forced up the well -- this is a health and safety hazard.

When sampling a well, it is important to:

- # Select sampling devices constructed of inert materials such as stainless steel, non-flexible PVC, or Teflon (see Exhibit 1.4-24);
- # Place plastic sheeting around the wellhead so that sampling equipment does not come into contact with the soil or drilling fluids;
- # Measure and record the water level and free product thickness, if product is present, to the nearest 0.01 foot;

Exhibit 1.4-23

Recommended Purging Equipment

Diameter Casing	Bailer	Peristaltic Pump	Vacuum Pump	Airlift	Diaphragm "Trash" Pump	Submersible Diaphragm Pump	Submersible Electric Pump	Submersible Electric Pump with Packer
<u>1.25 inch</u>								
Water level <25 ft		X	X	X	X			
Water level >25 ft				X				
<u>2-inch</u>								
Water level <25 ft	X	X	X	X	X	X		
Water level >25 ft	X			X		X		
<u>4-inch</u>								
Water level <25 ft	X	X	X	X	X	X	X	X
Water level >25 ft	X			X		X	X	X
<u>6-inch</u>								
Water level <25 ft				X	X		X	X
Water level >25 ft				X			X	X
<u>8-inch</u>								
Water level <25 ft				X	X		X	X
Water level >25 ft				X			X	X

Source: [4]

Exhibit 1.4-24
Advantages and Disadvantages of Different
Ground-Water Sample Collection Methods

Category	Method	Advantages	Disadvantages	
<i>Down-Hole Collection Devices</i>		<i>Methods in this category offer a greater potential to preserve sample integrity than many other methods because pressure differences are not used to collect sample.</i>	<i>Most devices in this category are unsuitable for purging because they provide only small, volumes of water. This problem can be avoided by using another method, which may be disruptive, to purge the well prior to using the down-hole collection device for sampling.</i>	
		<i>Bailers</i>	<i>Inexpensive to purchase or fabricate and economical to operate. This may permit the assignment of one collection device for each installation to be sampled, thereby circumventing problems of cross-contamination.</i>	<i>Usually very time consuming when used for purging installations, especially when the device has to be lowered to great depths. It can also be very physically demanding on the operator when the device is lowered and raised by hand.</i>
			<i>Very simple to operate and requires no special skills.</i>	<i>Can cause chemical alterations due to degassing, volatilization, or atmospheric invasion when transferring the sample to the storage container.</i>
			<i>Easily cleaned, though cleaning of ropes and/or cables may be more difficult.</i>	
			<i>Can be made of inert materials.</i>	
		<i>Mechanical Depth-Specific Samplers</i>	<i>Very portable, and requires no power source.</i>	
			<i>Inexpensive to construct.</i>	<i>Some of the materials used can cause contamination (e.g., rubber stoppers).</i>
			<i>Very portable and requires no power source.</i>	<i>Activating mechanism can be prone to malfunctions.</i>
			<i>Stratified sampler is well suited for sampling distinct layers of immiscible fluids.</i>	<i>May be difficult to operate at great depths.</i>
			<i>Can be made of inert materials.</i>	<i>Can cause chemical alternations when transferring sample to storage container.</i>
			<i>Stratified sampler is easily cleaned.</i>	<i>Difficult to transfer sample to storage container.</i>
		<i>Pneumatic Depth-Specific Samplers</i>	<i>Can be made of inert materials.</i>	<i>Kemmerer sampler is difficult to clean thoroughly.</i>
<i>Easily portable, and requires only a small power source (e.g., hand pump).</i>	<i>Types that are commercially available are moderately expensive.</i>			
<i>Solinst sampler and Syringe sampler can be flushed down-hole with the water to be sampled</i>	<i>Westbay sampler is only compatible with the Westbay casing system.</i>			
<i>Syringe of the syringe sampler can be used as a short-term storage container.</i>	<i>Solinst and Westbay samplers are difficult to clean.</i>			
<i>Syringe sampler is very inexpensive.</i>	<i>Materials used in disposable syringes of syringe samplers can contaminate the water.</i>			
	<i>Water sample comes in contact with pressurizing gas in Solinst and Westbay samplers (but not in syringe samplers).</i>			

Source: [5].

Exhibit 1.4-24
Advantages and Disadvantages of Different
Ground-Water Sample Collection Methods
(continued)

<i>Category</i>	<i>Method</i>	<i>Advantages</i>	<i>Disadvantages</i>
	<i>Suction-Lift Methods</i>	<p><i>Simple, convenient to operate, and easily portable.</i></p> <p><i>Inexpensive to purchase and to operate.</i></p> <p><i>Easily cleaned.</i></p> <p><i>Components can be of inert materials.</i></p> <p><i>Depending on the pumping mechanism, these methods can be very efficient for removing standing water from the sampling installations.</i></p> <p><i>Provides a continuous and variable flow-rate.</i></p>	<p><i>Limited to situations where the water level is less than 7-8 m (23-26 feet) below ground surface.</i></p> <p><i>Can cause sample bias as a result of degassing and atmospheric contamination, especially if the sample is taken from an in-line vacuum flask.</i></p> <p><i>Can cause contamination if water is allowed to touch pump components.</i></p>
<i>Positive-Displacement Methods</i>		<p><i>Methods in this category offer reduced possibility of degassing and volatilization because the sample is delivered to ground surface under positive pressure. In some situations, the pressure at ground surface may be substantially less than the natural water pressure in the formation and thus the degassing problem cannot be ignored entirely.</i></p> <p><i>Sample does not contact the atmosphere.</i></p> <p><i>Sampling pumps for use in monitoring wells as small as 3.8-5 cm (1.5-2 in) are commercially available.</i></p> <p><i>Most of the commercially available devices have a sufficient flow rate for purging wells.</i></p>	<p><i>Cost of the commercially available pumps used in these methods is substantial (roughly \$2,000 to \$5,000). It would therefore not be feasible to dedicate a sampling pump to each sampling point.</i></p> <p><i>Can be difficult to clean between sampling sessions.</i></p> <p><i>Cleaning of cables and/or delivery tubing is required between sampling points.</i></p> <p><i>Commercially available devices are too large for very small-diameter wells such as the bundle piezometers.</i></p>
	<i>Submersible Centrifugal Pumps</i>	<p><i>Can pump at large and variable flow rates.</i></p> <p><i>Johnson-Keck pumps can fit down wells as small as 5 cm (2 in).</i></p> <p><i>Johnson-Keck pump is easily portable.</i></p> <p><i>Conventional pumps are usually much cheaper than the Johnson-Keck pump.</i></p> <p><i>Johnson-Keck pump offers little potential for sample contamination because it is made mostly of stainless steel and Teflon.</i></p>	<p><i>Subject to excessive wear in abrasive or corrosive waters.</i></p> <p><i>Conventional submersible pumps cannot be used in wells with diameters less than about 12 cm (4 in).</i></p> <p><i>Potential for contaminating water because of contact with metals and lubricants is greater in conventional pumps.</i></p> <p><i>Johnson-Keck pump has intermittent flow (15 min on, 15 min off).</i></p>

Source: [5].

Exhibit 1.4-24
Advantages and Disadvantages of Different
Ground-Water Sample Collection Methods
(continued)

Category	Method	Advantages	Disadvantages
	Submersible Piston Pumps	<p>Gas-drive piston pumps have small power requirements.</p> <p>Gas-drive piston pump of Gillham and Johnson (1981) is inexpensive and can be assigned permanently to sampling point, thereby eliminating problems of cross-contamination.</p> <p>Double-acting pumps have continuous adjustable flow rates.</p> <p>Can be built of inert materials (most commercially available pumps are not, however).</p>	<p>Rod pumps require large power source and are permanently mounted.</p> <p>Difficult to clean.</p> <p>When used as part of a well, the gas drive pump of Gillham and Johnson (1981) cannot be retrieved for servicing or repair.</p> <p>Single-acting pumps have intermittent flow.</p>
	Gas Squeeze Pumps	<p>Can be built of inert materials.</p> <p>Commercially available pumps can fit in wells as small as 5 cm (2 in).</p> <p>Can easily be taken apart for cleaning.</p>	<p>Intermittent, but adjustable flow.</p> <p>Requires large, but portable, power source.</p> <p>Can be inconvenient to clean between sampling sessions.</p>
Gas-Lift Methods		<p>Simple to construct or are available commercially at relatively low cost.</p> <p>Can be used in very narrow wells.</p> <p>Can be easily portable.</p> <p>Easily cleaned.</p>	<p>Can only be used efficiently when roughly one-third of the underground portion of the device is submerged.</p> <p>Contamination of the sample with the driving gas, atmospheric contamination, and degassing are all unavoidable.</p> <p>Needs large power source (gas).</p>
Gas-Drive Methods		<p>Offers good potential for preserving sample integrity because (1) very little of the driving gas comes in contact with the water sample, and (2) the sample is driven by a gradient of positive pressure.</p> <p>Can be incorporated as part of the sampling installation, thereby removing the possibility of cross-contamination.</p> <p>The triple-tube sampler is well suited for wells of very narrow diameter (e.g., 0.95 cm [3/8 in]) where the only other possible sampling method is narrow-tube bailers, or suction-lift (when applicable).</p> <p>Inert materials can be used.</p>	<p>Not very efficient for purging wells larger than about 2.5 cm (1 in).</p> <p>Can be difficult to clean between sampling sessions.</p> <p>Because the driving gas comes in contact with the water, the beginning and the end of the slug of water obtained at the surface can be contaminated.</p> <p>When used as part of a permanent sampling installation, they cannot be retrieved for repair or servicing.</p> <p>Pumps intermittently and at a variable flow rate.</p>

Source: [5].

Exhibit 1.4-24
Advantages and Disadvantages of Different
Ground-Water Sample Collection Methods
(continued)

<i>Category</i>	<i>Method</i>	<i>Advantages</i>	<i>Disadvantages</i>
<i>Jet Pumps</i>		<p>Can be used at great depths.</p> <p>Useful for purging monitoring wells.</p>	<p>Uses circulating water which mixes with the pumped water. A large amount of water needs to be pumped before the circulating water has a composition that is close to the water in the installation.</p> <p>The water entering the venturi assembly is subjected to a pressure drop (which may be large), and can therefore undergo degassing and/or volatilization.</p> <p>The circulating pump at the surface can contaminate the pumped water because of its materials and lubricants.</p>
<i>Destructive Sampling Methods</i>		<p>Can provide very useful information in the reconnaissance surveys and in other specific field situations.</p> <p>Most of the techniques are used during the drilling operation and will not interfere with the construction of a permanent well.</p> <p>Coring-extraction methods are the only convenient means of obtaining several parameters related to both the liquid and soil phases (e.g., exchangeable cations, total microbial population, samples of the formation, etc.), and also, for certain situations they may be the least bias-inducing method (e.g., in very fine-grained formations).</p> <p>Temporary wells can, in some situations, be the most cost-effective way of obtaining preliminary and/or reconnaissance data.</p>	<p>Because no permanent well is left in the ground, these methods cannot be used for monitoring long-term trends in water quality. In most cases, however, they do not interfere with the construction of permanent wells.</p> <p>Can result in large drilling costs.</p> <p>Water contained in cores can be contaminated with drilling fluids and can undergo degassing and volatilization at the ground surface.</p>

Source: [5].

NOTES

- # Use a sampling technique suited to the contaminants of interest (e.g., do not use methods or pump at a rate that would liberate volatiles, if you are sampling for volatiles; and
- # Discard the first few volumes of water withdrawn from the well before taking a sample.

Do not collect water samples for dissolved contaminant analysis from any well where free product is present.

5. Determining the Extent of Structural Contamination

Both surface and subsurface spills can contaminate structures, including buildings, sewer lines, water mains, machinery equipment, or any other physical man-made features of the site. You may determine the extent of structural contamination through a visual inspection or sampling survey.

A visual inspection can identify gross contamination such as apparent free product pools or stained surfaces. Rafters, ventilation ducts, sumps, crawl spaces, window wells, and the like should be inspected for visual evidence of deterioration (e.g., as a result of strong chemical reactions) as well as for chemical residues.

Sampling surveys may identify contamination not apparent during visual inspections. A sampling survey can be as simple as using air monitoring instruments (e.g., HNu meters or organic vapor analyzer) to detect organic vapors or can involve taking samples from the surface of the structure. There are two basic techniques for sampling contamination on structural or equipment surfaces: wet-wipe and dry-wipe. With wet-wipe techniques water or some other solvent is used to extract material off the contaminated structural surface when it is wiped with a Q-tip or filter paper disk, whereas with dry-wipe techniques no solvent is used.

6. Documenting the Site Investigation

You must keep some sort of a chronological record of your site investigation activities for each spill whether it is a personal field logbook or completed Job Inspection Reports (see Part 4, Section 1, Case Documentation). Do not hesitate to record comments on the information you collect, but make sure facts are always distinguished from guesses or estimations. Do not record personal comments that could be regarded as offensive or make allegations in your field notes. Remember that these notes become part of the official case file, and as such, may be subject to legal scrutiny. It is, therefore, best to restrict your entries to observations of fact.

Include the following information/illustrations in the spill case records:

NOTES

- # A simple site and vicinity map (see Attachment 1.4-2 or develop your own);
- # Dates and times of activities and findings;
- # Names and titles of principal people involved in a specific event;
- # Source(s) of information;
- # Photographs of site conditions; and
- # Other unusual or noteworthy events you feel are important.

Again, the worksheets provided as an attachment to this section may be useful for organizing the information collected in a site investigation. Exhibit 1.4-25 summarizes additional recordkeeping guidelines.

The information contained in this chronological record will help you prepare the Investigative Summary Report (ISR), which is the official document of your findings from the investigations. Step-by-step guidance on preparing the ISR are provided in Part 4, Section 1, Case Documentation.

7. Site Restoration

Almost every spill investigation/cleanup will involve disturbing the site area in some way. How much time, effort, and money you should invest in restoring a site will depend on a number of factors, that is, your decision will vary by site and circumstance. The following, however, are some general guidelines for making that decision. Additional questions should be directed to your RSE or to Central Office staff.

1. First, make sure the affected parties understand what you intend to do and the possible consequences of those actions before you start any spill investigation/cleanup.
2. In cases of a suspected leaking tank, explain to the owner that you may:
 - Test the tank system, and if the system tests tight and there is no other evidence of a problem, the site will be restored by NYSDEC;
 - Test the tank system, and if the system is found to be leaking, you will remove the tanks and contaminated soil; possibly install monitoring wells and recovery system; and will restore the site to a safe condition only. NYSDEC will not install new tanks, hook up tanks, replace a leaking tank, repave an area, or rebuild the pump islands.

NOTES

3. Explain that due care will be exercised to minimize the impact of the investigation/cleanup work, but that this work has to be done to protect the environment/public health. (In some cases this will give the owner added incentive to clean up the spill himself or herself.)
4. When dealing with other parties affected by the spill, but not the cause of the spill, you should explain that you will restore the site to as close as possible to the original conditions, but that you are not authorized to do additional work. For example, if you remove part of a gravel driveway, you will replace it with a gravel driveway, not a black-top driveway.

Exhibit 1.4-25

Suggested Recordkeeping Practices Checklist for Spill Investigations

- # Fill out Spill Report Form with information received from caller.
 - # Phone parties with information on spill and record contacts (e.g., spiller, witnesses, other agency personnel).
 - # Record information gained in initial visit to spill site, including date and time of visit, your observations, statements by witnesses, statements by alleged spiller, actions taken, etc. Use Job Inspection Form or keep log book.
 - add brief summary to Spill Report Form
 - attach additional notes/reports to Spill Report Form
 - attach media reports or reports from other agencies
 - stick to factual events; no allegations or personal comments.
 - # Make a more detailed report on spill if subsequent visits to site are necessary. Cover chronological events.
 - include names and titles of principals involved in spill
 - state if and when samples, measurements, etc., were taken
 - include dates and times (if possible) of events such as contractor call-out or when alleged spiller was directed to start clean up
 - include any other information you deem important
 - include maps and refer to them in reports.
 - # Take all samples in accordance with approved procedures and follow quality assurance/quality control guidelines.
 - record time, date, and location of samples taken
 - # Take pictures of site features, path of spill (if evident), source of spill, free product (if evident), sampling locations.
 - number and date all pictures and indicate location and direction of picture taken on reverse side.
-

REFERENCES

1. Freeze, R.A. and Cherry, J.A. Ground Water, Prentice-Hall, Inc. Englewood Cliffs, NJ, 1979.
2. American Petroleum Institute. Underground Spill Cleanup Manual. API Publication 1628. June 1980.
3. Dricoll, F.G. Ground Water and Wells. 2nd Edition. Johnson Division, St. Paul, MN. 1986.
4. California Leaking Underground Fuel Tank Field Manual: Guidelines for Site Assessment, Cleanup, and Underground Storage Tank Closure. May 1988.
5. American Petroleum Institute. Advantages and Disadvantages of Ground-Water Sample Collection Methods. API Publication 4367.
6. Emergency Action Guides. Association of American Railroads. Washington, D.C. 1987.

ATTACHMENT 1.4-1

**CHEMICAL COMPOSITION OF GASOLINE
AND SELECTION OF INDICATOR CHEMICALS FOR ANALYSIS**

The following material was extracted from "The Appropriateness of Benzene as an Indicator Chemical for Leaking UST Sites" (March 1987), prepared for the U.S. EPA's Office of Underground Storage Tanks by Camp, Dresser, and McKee, Inc. Exhibit 1.4-26 on the chemical Composition was taken from the California Leaking Underground Fuel Tank Manual: *Guidelines for Site Assessment, Cleanup and Underground Storage Tank Closure* (May 1988).

Chemical Composition of Gasoline

Gasoline is a colorless blend of volatile liquid-petroleum fractions. A typical blend of gasoline will contain several hundred hydrocarbons. In addition, gasoline additives are blended into gasoline to function as anti-knock agents, anti-oxidants and sweetening inhibitors, metal deactivators, corrosion inhibitors, deicing and anti-stall agents, preignition preventors, dyes, and upper cylinder lubricants.

Aromatics are known to be the most toxic constituents in gasoline, although the toxicity of many of the additives--which are found in significantly smaller concentrations than the aromatics--is unknown. It is virtually impossible to create a detailed and specific breakdown of the chemicals in gasoline in general and of the additives in particular. The composition of gasoline varies in terms of the crude oil from which it was produced and with seasonal operating requirements. Product composition may change daily depending on refinery operations. Product additives can be changed seasonally to accommodate temperature changes. The lucrative market for effective chemical additives generates numerous new additive formulations each year. Moreover, because most additives are patented, their chemical formulations and uses in specific products are often considered proprietary. See also Exhibit 1.4-26.

1. Chemicals of Possible Concern Other Than Benzene, Toluene, and Xylene (BTX)

There are some 241 chemicals in petroleum products, of which nine constituents of gasoline are regulated under CERCLA as hazardous substances (including benzene, toluene, and xylene). In addition, there are four chemicals used as gasoline additives that are regulated under CERCLA. These 13 chemicals, which are currently known to be in gasoline and regulated under CERCLA, are listed in Exhibit 1.4-27.

The toxicities of these 13 compounds are also shown in Exhibit 1.4-27 based on final toxicity Reportable Quantity (RQ) categories assigned to each chemical under CERCLA. An RQ is that quantity of a substance which, if released, triggers a requirement to report that release. An RQ value reflects EPA's subjective judgment of which substances are the most hazardous. The lower the RQ value, the more toxic the substance. Various measures of toxicity have been established in other fields such as industrial hygiene and safety, cancer research, and wildlife conservation. However, these measures of toxicity are not necessarily equivalent to one another, or directly comparable. They do provide a relative benchmark for determining the principal chemicals of concern (albeit for different reasons) to protect public health and the environment.

Based on the RQ values contained in Exhibit 1.4-27, there are eight chemicals besides benzene, toluene, o-xylene, m-xylene, and p-xylene that might be of concern because of their toxicity:

- # ethylbenzene
- # naphthalene
- # phenol
- # ethylene dibromide (EDB)
- # ethylene dichloride (EDC)
- # tetraethyl lead (TEL)
- # dimethylamine
- # cyclohexane

To evaluate the relative health threats posed by these eight substances certain other factors are considered:

- # The percentage by volume and weight of each substance in gasoline;
- # The percentage of gasolines that contain each substance; (i.e., its prevalence in the marketplace);
- # The ease with which the substances move into the environment (mobility, fate, and transport);

2. Presence in Gasoline Products

Exhibit 1.4-27 includes data that address these factors for the 13 chemicals identified as hazardous substances. Data gaps exist, especially with regard to percentages by volume in gasoline and the percentage of gasolines that contain these compounds. We have attempted to fill in the data gaps, but, in some cases, the information is not necessarily reliable. A rating that reflects the confidence we have in the composition data is also included on Exhibit 1.4-27. A brief discussion of each compound is presented below.

Ethylbenzene

Ethylbenzene makes up a significant part of the aromatic portion of gasoline (up to 4.6% by volume). It is a colorless liquid used in both petroleum refining and the organic chemical industry.

EDB

Of the eight chemicals, EDB is one of the two pure products that are potential carcinogens. EDB is an additive, which has been found in concentrations of 177 ppm, 1.9 ppm, and 0.7 ppm for regular, unleaded, and super unleaded gasolines, respectively. It makes up 0.024 percent of gasoline by weight. What percentage of gasolines contain EDB is not precisely known, but it is estimated that less than 40 percent contain this chemical; that percentage is expected to decline as the use of lead in gasoline is phased out. EDB has also been widely used as an agricultural fumigant, which has led some to question the value of EDB as a reliable indicator of gasoline contamination, especially in agricultural areas.

EDC

EDC, another additive, is the other chemical that is a potential carcinogen. The exact percentage of EDC in gasoline, by weight, is not known, but it has been estimated to be less than the percentage, by weight, of EDB found in gasoline. It is not known what percentage of gasolines contain EDC, but, again, estimates are that less than 40 percent contain this chemical, and the percentage is likely to decline as the use of lead in gasoline is phased out.

Tetraethyl Lead

TEL is an additive that is being phased out per government order. Again, it is not known what percentage of gasolines contain TEL, but it is believed that less than 40 percent contain TEL; its use will decrease in the future. TEL does not readily partition into air or water. Rather, it has a strong affinity for soils and, in those rare instances when it is detected, it is typically found at or very near the spill source.

Naphthalene

Naphthalene is another chemical that does not move in the environment very easily. It is found in as much as 90 percent of gasolines being marketed today, accounting for less than 0.1 percent of the weight of gasoline.

Phenol

Phenol is known to biodegrade quickly into a less toxic compound. It is found in more than 90 percent of the gasolines being marketed today.

Dimethylamine

Few data were found on dimethylamine. Dimethylamine is one of the most soluble additives in gasoline.

Cyclohexane

Cyclohexane is another colorless component of gasoline. It makes up 0.17 percent of the weight of gasoline.

3. Fate and Transport

There are two types of fate mechanisms by which chemicals are transported or transformed. Physical processes, which include solubility, vaporization, and adsorption, transfer the substances across media/phase interfaces. Kinetic processes, which include biotic and abiotic chemical transformations, decrease the concentration of a chemical by degrading it into other products. How a chemical is affected by fate mechanisms depends on a number of specific chemical and environmental factors. Exhibit 1.4-27 lists the solubilities, vapor pressures, and adsorption coefficients that were available for the 13 chemicals that are regulated under CERCLA and also are found in gasoline.

Of the eight chemicals of concern, four are more soluble than benzene:

<u>Compound</u>	<u>Times more soluble than benzene</u>
EDB	2 times
EDC	4 times
Phenol	37 times
Dimethylamine	560 times

Only ethylbenzene is as volatile as benzene, toluene, or xylene.

Given that these chemicals move into air and water more easily than BTX, one would expect to find these even when BTX is not detected; but this is not necessarily the case. The likelihood of detecting a particular contaminant is more a function of its original concentration in gasoline as well as the extent to which it's used in a gasoline product.

For example, BTX is used in almost every gasoline, and can be detected in significant concentrations. One would expect to find BTX at almost every leaking gasoline UST site where free product exists.

On the other hand, EDB, which makes up only 0.02 percent of gasoline and is not used in every gasoline, would be found in significantly lower concentrations than benzene (or toluene or xylene). This does not mean that EDB will never be detected. EDB has been detected in wells in the vicinity of known gasoline releases in Florida and Maine, among other states. It is unclear, however, whether and to what extent the detected EDB originates from gasoline or from agricultural fumigants. Sampling for a wide range of compounds in the low parts per billion range could lead to a number of "false positives."

In focusing efforts on cleaning up BTX--which make up a considerably larger portion of gasoline and are found in much greater concentrations than any of the additives--the most significant public health and environmental concerns are being addressed. What remains are low levels of BTX and some of the additives. The health hazard posed by low level concentrations of these additives is unknown.

4. Measurement of Benzene and Other Hydrocarbons in Aged Plumes

Benzene is the gasoline constituent most often used to determine the extent of a leaking UST problem. Benzene is relatively volatile and soluble, so that it can usually be detected in both air and water. Toluene and xylene are sometimes used in conjunction with benzene to make these determinations. However, relying on measurements of benzene alone to provide an accurate characterization of the extent of a problem and the hazard it represents could lead to incorrect assumptions about where and how concentrated the plume is (and consequently, where the focus of corrective actions should be) especially with regard to aged plumes.

a. Monitoring Soil Gases in Aged Plumes

Soil gas monitoring can be used to determine the extent of dissolved plumes resulting from a gasoline release. The atmosphere above the ground acts as a sink while the free and/or dissolved portion of the gasoline spill acts as a source of volatile organics. Thus, a situation arises where volatile organics can move up through the unsaturated zone. Measuring the concentrations of diffusing volatile organics in shallow soil gas can provide an estimate of the direction, extent, and chemical composition of an underground gasoline plume. Most of the major volatile constituents found in gasoline can be successfully measured with this technique.

Measuring benzene in soil gas can -- in certain instances -- be used to determine the extent of the gasoline plume. However, because of benzene's volatility, solubility, and biodegradability, the results of soil gas monitoring for benzene will not be reliable if the sampling is not undertaken close to the source, or if the gasoline plume is significantly "weathered" (i.e., aged). If the plume has aged significantly, or has migrated from the source, chances are that significant amounts of benzene and other volatile organics have evaporated into the air or dissolved in the water, and what benzene remains in the soil gas is at such low concentrations that the remote vapor sensing equipment may not detect its presence. Therefore, to ensure more reliable determinations of the extent of a plume, groups of volatile organics should be measured, either as BTX or total volatile organics or total petroleum hydrocarbons, instead of just benzene (or any one specific volatile compound for that matter).

b. Monitoring Water Quality in Aged Plumes

Water quality samples taken from an aged plume are also likely to show different constituents than samples taken from a plume from a "newer" spill because different components of gasoline are adsorbed, hydrolyzed, biodegraded, and volatilized at different rates.

Studies of time for several gasoline constituents to biotransform in ground water under aerobic conditions has shown that after 124 days, significant amounts of five of the gasoline constituents of concern can be more or less removed or transformed. Virtually, all of the mass of BTX that was injected was biodegraded after 434 days.

These findings suggest that a spill that has been in the ground as long as six months can undergo significant chemical transformations. *A conservative assumption is that a gasoline plume that has been in the ground longer than 2 years can be considered an "aged" plume.*

It is possible that if a plume had been in the ground long enough, and all the free product had been removed, then no benzene, toluene, or xylene would be detected. If that were the case, and water quality samples showed no BTX to be present, a conclusion might be drawn that no release occurred. To avoid this misinterpretation, the analysis might focus on other constituents in gasoline that are more persistent than BTX or the alcohols. It is difficult, however, to find constituents that do not biodegrade or volatilize or hydrolyze to some degree.

The best indicator chemicals for aged plumes are refractory compounds that have high molecular weight. The more complex hydrocarbons (such as those associated with No. 2 and No. 6 fuel oils) are likely to be present to some degree after long periods of time. C22 compounds would take considerable time to break down (see Exhibit 1.4-28 at the end of this attachment). Other persistent chemicals, such as tetraethyl lead, which are not highly soluble or volatile, might be found in trace amounts close to the spill source. Because these compounds are not used in all fuels, they may not be detected at all locations.

Ground water beneath the floating product plume is enriched with ethylbenzene, benzene, toluene, and xylene. The more soluble compounds dissolve in ground water and disperse. One of the most soluble compounds in gasoline is methyl-tertiary butyl ether (MTBE).

MTBE is becoming one of the more popular octane-enhancing additives used by the gasoline companies, now that the use of tetraethyl lead is being phased out. Commercially produced beginning only in 1979, MTBE is now among the top 50 chemicals produced in the United States. It is used in only about 10 percent of the gasolines produced today. Its percentage in gasoline, by weight, is not known, nor is the degree of health threat posed by low level concentrations of MTBE. It is an irritant, like many other chemicals found in gasoline. It may be a nervous system depressant. It is up to 24 times more soluble than benzene.

Because it is one the most soluble compounds in gasoline, MTBE may be the only contaminant whose concentration exceeds the detection limit over large areas of the plume, especially at the edges of the plume. MTBE plumes are believed to occur as "haloes" around gasoline plumes. Thus, it is possible that a part of the plume might go undetected if benzene alone were used as the sole indicator compound. Sampling

for MTBE along with benzene might allow for a more accurate delineation of the gasoline plume, and more importantly, its direction and the extent of migration, if the plume source happened to be one of the 10 percent of gasolines that contain MTBE.

5. Analytical Measurement of Chemicals of Concern

Exhibit 1.4-27 presents the analytical method used for analyzing each constituent. There are two basic types of analysis: purge and trap gas chromatography (GC), which determines presence, and gas chromatography/mass spectrometry (GC/MS), which provides quantitative concentrations. A brief discussion of each follows:

Method 601 is a purge and trap gas chromatographic method used to determine the presence of 29 halocarbons. It can be used to detect EDB and EDC. Method 624 provides GC/MS conditions appropriate for the qualitative and quantitative confirmation of results.

Method 602 is a purge and trap gas chromatographic method used to determine the presence of various purgeable aromatics, including benzene, toluene, xylene, and ethylbenzene. Method 624 provides GC/MS conditions appropriate for the qualitative and quantitative confirmation of results.

Method 604 is a GC method used to determine the presence of phenols and certain substituted phenols. Method 625 provides GC/MS conditions appropriate for the quantitative confirmation of results.

Method 607 is a GC method used to determine the presence of nitrosamines. A modified method 607 can be used to determine the presence of dimethylamine. Method 625 provides GC/MS conditions appropriate for the qualitative and quantitative confirmation of results.

Method 610 is a GC method used to determine the presence of certain polynuclear aromatic hydrocarbons, including naphthalene. Method 625 provides GC/MS conditions appropriate for the qualitative and quantitative confirmation of results.

Method 624 can be used to quantitatively and qualitatively confirm the presence of (benzene, toluene, o-, m-, p-xylene, ethylbenzene, EDB, EDC, and cyclohexane) nine of the 13 compounds (volatile components).

Method 625 can be used to confirm three of the 13 compounds shown in Exhibit 1.4-27.

Exhibit 1.4-26

Physical/Chemical Data for Gasoline

Physical Description: A volatile colorless to amber or pale brown liquid, which may also be dyed various colors.

Chemical Description: A complex mixture of hydrocarbons, averaging five to ten carbon atoms per molecule.

Virgin gasoline usually contains:

- # Around 50 percent alkanes (paraffins)
- # Around 40 percent cyclic alkanes (naphthenes)
- # Around 10 percent aromatics.

Blended gasolines are mixtures of virgin gasoline, catalytically cracked gasoline, and thermally reformed gasolines, and may contain up to 30 percent alkenes (olefins).

Constants: Flash point: -38°F to -50° (-38.9 to 45.6°C) closed cup.

Density: 0.66 to 0.70

Auto-ignition temperature: minimum of 536°F (280°C); maximum of 853°F 456°C); varies with grade

Vapor density: 3 to 4 times that of air. Vapors may travel a considerable distance to a source of ignition and flash back. Vapors may persist in pits, hollows, and depressions.

Flammability limits of vapor in air:

- Upper: 7.1-7.6 percent
- Lower: 1.2-1.4 percent

Viscosity: Slightly less than water

Average boiling range: 140-390°F (60-99°C) at 1 atmosphere.

Source: [6].

Exhibit 1.4-27

Toxicity, Chemical Characteristics, and Treatment
 Characteristics of Benzene and other Toxic Compounds in Gasoline

COMPOUND	TOXICITY	MASS		PREVALENCE	FAIE & TRANSPORT			TREATABILITY		MEASUREMENT		CONFIDENCE IN DATA ⁴
	FINAL RQ (kg) ¹	% VOLUME IN GASOLINE	% WEIGHT IN GASOLINE ⁵	% OF GASOLINES CONTAINING CHEMICAL	WATER SOLUBILITY @ 20 degrees C (mg/l)	VAPOR PRESSURE (TORR) ²	DEGREE OF BIOGRADE-ABILITY	HENRY'S CONSTANT (atm·m ³ /mol)	GAC ADSORPTION COEFFICIENT (mg/l)	ANALYTICAL METHOD USED		
										GC	GC/MS	
1. BENZENE	4.54	1-2%	.81	>99%	1,780	750	SOME	0.00569	1	602	624	+
2. TOLUENE	45400	4.0%	12.02	>99%	815	220	SOME	0.00637	26	602	624	+
3. XYLENE-M	45400	5-8%	3.83	>99%	175	50	SOME	0.00704	85	602	624	+
4. XYLENE-O	45400	5-8%	1.93	>99%	162	60	SOME	0.00704	85	602	624	+
5. XYLENE-P	45400	5-8%	1.58	>99%	198	6.5	SOME	0.00704	85	602	624	+
6. ETHYLBENEZENE	45400	2-5%	1.70	>99%	152	7.0	SOME	0.00643	53	602	624	+
7. NAPHTHALENE	45.40	.7%	0.10	>90%	31.1	1.0 ³	READILY	0.0011	132	610	625	+
8. PHENOL	45400	-	-	>90%	66,667	0.5	READILY	0.454E-7	21	604	625	+
9. EDB	4.54	0.01%	0.024	<10%	4,310	11.0	SOME	0.00067	<1	601	624	0
10. EDC	45.40	0.01%	<0.024	<10%	8,690	61.0	SOME	0.00098	<1	601	624	0
11. TETRAETHYL LEAD	4.54	-	-	<10%	008	0.2	SOME	0.00060	>1	ATC/MC ABSORPTION MODIFIED 607		0
12. DIMETHYLAMINE	45400	-	-	-	1 X 10 ⁶	1,2450	READILY	0.00009	<1	MODIFIED 601		-
13. CYCLOHEXANE	45400	<0.7%	0.17	-	665	77.0	SOME	0.0001	>1	601	624	-

1. THE LOWER THE RQ VALUE, THE MORE TOXIC THE CHEMICAL IS IN PURE PRODUCT FORM

2. AT 20 DEGREES C UNLESS OTHERWISE NOTED

3. AT 53 DEGREES C

4. + = HIGHLY CONFIDENT; 0 = SOMEWHAT CONFIDENT; - = NOT CONFIDENT

5. SOURCE: MAYNARD AND SANDELS, 1969

Exhibit 1.4-28
Chemical Composition of Gasoline

Compound	Number of Carbons	Concentration (Percent by Weight) (a)	Reference
<u>Straight Chain Alkanes</u>			
Propane	3	0.01 - 0.14	8,10
n-Butane	4	3.93 - 4.70	8,10,11
n-Pentane	5	5.75 - 10.92	8,10,11
n-Hexane (b)	6	0.24 - 3.50	8,10,11
n-Heptane	7	0.31 - 1.96	10,11
n-Octane	8	0.36 - 1.43	10
n-Nonane	9	0.07 - 0.83	10
n-Decane	10	0.04 - 0.50	10
n-Undecane	11	0.05 - 0.22	10
n-dodecane	12	0.04 - 0.09	10
<u>Branched Alkanes</u>			
Isobutane	4	0.12 - 0.37	8,10
2,2-Dimethylbutane	6	0.17 - 0.84	10
2,3-Dimethylbutane	6	0.59 - 1.55	8,10,11
2,2,3-Trimethylbutane	7	0.01 - 0.04	10
Neopentane	5	0.02 - 0.05	10
Isopentane	5	6.07 - 10.17	8,10,11
2-Methylpentane	6	2.91 - 3.85	8,10,11
3-Methylpentane	6	2.4 (vol)	8,10,11
2,4-Dimethylpentane	7	0.23 - 1.71	8,10,11
2,3-Dimethylpentane	7	0.32 - 4.17	8,10,11
3,3-Dimethylpentane	7	0.02 - 0.03	10
2,2,3-Trimethylpentane	8	0.09 - 0.23	10,11
2,2,4-Trimethylpentane	8	0.32 - 4.58	8,10
2,3,3-Trimethylpentane	8	0.05 - 2.28	10
2,3,4-Trimethylpentane	8	0.11 - 2.80	10,11
2,4-Dimethyl-3-ethylpentane	9	0.03 - 0.07	10
2-Methylhexane	7	0.36 - 1.48	10
3-Methylhexane	7	0.30 - 1.77	10,11
2,4-Dimethylhexane	8	0.34 - 0.82	10
2,5-Dimethylhexane	8	0.24 - 0.52	10
3,4-Dimethylhexane	8	0.16 - 0.37	10
3-Ethylhexane	8	0.01	10
2-Methyl-3-ethylhexane	9	0.04 - 0.13	10
2,2,4-Trimethylhexane	9	0.11 - 0.18	10
2,2,5-Trimethylhexane	9	0.17 - 5.89	10

Exhibit 1.4-28
Chemical Composition of Gasoline
(continued)

Compound	Number of Carbons	Concentration (Percent by Weight) (a)	Reference
2,3,3-Trimethylhexane	9	0.05 - 0.12	10
2,3,5-Trimethylhexane	9	0.05 - 1.09	10
2,4,4-Trimethylhexane	9	0.02 - 0.16	10
2-Methylheptane	8	0.48 - 1.05	10
3-Methylheptane	8	0.63 - 1.54	10
4-Methylheptane	8	0.22 - 0.52	10
2,2-Dimethylheptane	9	0.01 - 0.08	10
2,3-Dimethylheptane	9	0.13 - 0.51	10
2,6-Dimethylheptane	9	0.07 - 0.23	10
3,3-Dimethylheptane	9	0.01 - 0.08	10
3,4-Dimethylheptane	9	0.07 - 0.33	10
2,2,4-Trimethylheptane	10	0.12 - 1.70	10
3,3,5-Trimethylheptane	10	0.02 - 0.06	10
3-Ethylheptane	10	0.02 - 0.16	10
2-Methyloctane	9	0.14 - 0.62	10
3-Methyloctane	9	0.34 - 0.85	10
4-Methyloctane	9	0.11 - 0.55	10
2,6-Dimethyloctane	10	0.06 - 0.12	10
2-Methylnonane	10	0.06 - 0.41	10
3-Methylnonane	10	0.06 - 0.32	10
4-Methylnonane	10	0.04 - 0.26	10
<u>Cycloalkanes</u>			
Cyclopentane	5	0.19 - 0.58	8,10
Methylcyclopentane	6	Not quantified	8
1-Methyl-cis-2-ethylcyclopentane	8	0.06 - 0.11	10
1-Methyl-trans-3-ethylcyclopentane	8	0.06 - 0.12	10
1-Cis-2-dimethylcyclopentane	7	0.07 - 0.13	10
1-Trans-2-dimethylcyclopentane	7	0.06 - 0.20	10
1,1,2-trimethylcyclopentane	8	0.06 - 0.11	10
1-Trans-2-cis-3-trimethylcyclopentane	8	0.01 - 0.25	10
1-Trans-2-cis-4-trimethylcyclopentane	8	0.03 - 0.16	10
Ethylcyclopentane	7	0.14 - 0.21	10
n-Propylcyclopentane	8	0.01 - 0.06	10
Isopropylcyclopentane	8	0.01 - 0.02	10
1-Trans-3-dimethylcyclohexane	8	0.05 - 0.12	10
Ethylcyclohexane	8	0.17 - 0.42	10

**Chemical Composition of Gasoline
(continued)**

Compound	Number of Carbons	Concentration (Percent by Weight) (a)	Reference
<u>Straight Chain Alkenes</u>			
cis-2-butene	4	0.13 - 0.17	10
trans-2-butene	4	0.16 - 0.20	10
Pentene-1	5	0.33 - 0.45	10
cis-2-pentene	5	0.43 - 0.67	8,10
trans-2-pentene	5	0.52 - 0.90	10,11
cis-2-hexene	6	0.15 - 0.24	10
trans-2-hexene	6	0.18 - 0.36	10
cis-3-hexene	6	0.11 - 0.13	10
trans-3-hexene	6	0.12 - 0.15	10
cis-3-heptene	7	0.14 - 0.17	10,11
trans-2-heptene	7	0.06 - 0.10	10
<u>Branched Alkenes</u>			
2-Methyl-1-butene	5	0.22 - 0.66	8,10,11
3-Methyl-1-butene	5	0.08 - 0.12	10
2-Methyl-2-butene	5	0.86 - 1.28	8,10,11
2,3-Dimethyl-1-butene	6	0.08 - 0.10	10
2-Methyl-1-pentene	6	0.20 - 0.22	10,11
2,3-Dimethyl-1-pentene	7	0.01 - 0.02	10
2,4-Dimethyl-1-pentene	7	0.02 - 0.03	10
4,4-Dimethyl-1-pentene	7	0.06 (vol)	11
2-Methyl-2-pentene	6	0.27 - 0.32	10,11
3-Methyl-cis-2-pentene	6	0.35 - 0.45	10
3-Methyl-trans-2-pentene	6	0.32 - 0.44	10
4-Methyl-cis-2-pentene	6	0.04 - 0.05	10
4-Methyl-trans-2-pentene	6	0.08 - 0.30	10
4,4-Dimethyl-cis-2-pentene	7	0.02	10
4,4-Dimethyl-trans-2-pentene	7	Not quantified	10
3-Ethyl-2-pentene	7	0.03 - 0.04	10
<u>Cycloalkenes</u>			
Cyclopentene	5	0.12 - 0.18	10
3-Methylcyclopentene	6	0.03 - 0.08	10
Cyclohexene	6	0.03	10
<u>Alkyl Benzenes</u>			
Benzene (b)	6	0.12 - 3.50	6,7,8,9, 10,11,12

Exhibit 1.4-28
Chemical Composition of Gasoline
(continued)

Compound	Number of Carbons	Concentration (Percent by Weight) (a)	Reference
Toluene (b)	7	2.73 - 21.80	5,6,7,8,9,10,11,12
o-Xylene (b)	8	0.68 - 2.86	6,9,10,12
m-Xylene (b)	8	1.77 - 3.87	10
p-Xylene (b)	8	0.77 - 1.58	10
1-Methyl-4-ethylbenzene	9	0.18 - 1.00	10
1-Methyl-2-ethylbenzene	9	0.19 - 0.56	6
1-Methyl-3-ethylbenzene	9	0.31 - 2.86	6,9,10,11
1-Methyl-2-n-propylbenzene	10	0.01 - 0.17	6,9,10
1-Methyl-3-n-propylbenzene	10	0.08 - 0.56	9,10
1-Methyl-3-isopropylbenzene	10	0.01 - 0.12	10
1-Methyl-3-t-butylbenzene	11	0.03 - 0.11	10
1-Methyl-4-t-butylbenzene	11	0.04 - 0.13	10
1,2-Dimethyl-3-ethylbenzene	10	0.02 - 0.19	6,10
1,2-Dimethyl-4-ethylbenzene	10	0.50 - 0.73	6
1,3-Dimethyl-2-ethylbenzene	10	0.21 - 0.59	6,9
1,3-Dimethyl-4-ethylbenzene	10	0.03 - 0.44	6,10
1,3-Dimethyl-5-ethylbenzene	10	0.11 - 0.42	6,10
1,3-Dimethyl-5-t-butylbenzene	12	0.02 - 0.16	10
1,4-Dimethyl-2-ethylbenzene	10	0.05 - 0.36	6,10
1,2,3-Trimethylbenzene	9	0.21 - 0.48	6
1,2,4-Trimethylbenzene	9	0.66 - 3.30	6,9,10,11
1,3,5-Trimethylbenzene	9	0.13 - 1.15	6,9,10
1,2,3,4-Tetramethylbenzene	10	0.02 - 0.19	6,10
1,2,3,5-Tetramethylbenzene	10	0.14 - 1.06	6,9,10
1,2,4,5-Tetramethylbenzene	10	0.05 - 0.67	6,9,10
Ethylbenzene (b)	8	0.36 - 2.86	6,9,10,11,12
1,2-Diethylbenzene	10	0.57	9
1,3-Diethylbenzene	10	0.05 - 0.38	6,9,10
n-Propylbenzene	9	0.08 - 0.72	6,9,10
Isopropylbenzene	9	<0.01 - 0.23	6,9,10,12
n-Butylbenzene	10	0.04 - 0.44	6,9,10
Isobutylbenzene	10	0.01 - 0.08	9,10
sec-Butylbenzene	10	0.01 - 0.13	9,10
t-Butylbenzene	10	0.12	9
n-Pentylbenzene	11	0.01 - 0.14	10
Isopentylbenzene	11	0.07 - 0.17	10

Exhibit 1.4-28
Chemical Composition of Gasoline
(continued)

Compound	Number of Carbons	Concentration (Percent by Weight) (a)	Reference
Indan 9	0.25 - 0.34	6	
1-Methylindan	10	0.04 - 0.17	10
2-Methylindan	10	0.02 - 0.10	10
4-Methylindan	10	0.01 - 0.16	10
5-Methylindan	10	0.09 - 0.30	10
Tetralin	10	0.01 - 0.14	10
<u>Polynuclear Aromatic Hydrocarbons</u>			
Napthalene (b)	10	0.09 - 0.49	6,10
Pyrene	16	Not quantified	6
Benz(a)anthracene	18	Not quantified	6
Benz(a)pyrene	20	0.19 - 2.8 mg/kg	6
Benzo(e)pyrene	20	Not quantified	6
Benzo(g,h,i)perylene	21	Not quantified	6
<u>Elements</u>			
Bromine		80 - 345 ug/g	3
Cadmium		0.01 - 0.07 ug/g	1
Chlorine		80 - 300 ug/g	3
Lead (c)		530 - 1120 ug/g	8
Sodium		<0.6 - 1.4 ug/g	3
Sulfur (d)		0.10 - 0.15 (ASTM)	
Vanadium		<0.02 - 0.001 ug/g ^{2,3}	
<u>Additives</u>			
Ethylene dibromide (b)		0.7 - 177.2 ppm	4
Ethylene dichloride (b)		150 - 300 ppm	8
Tetramethyl lead			
Tetraethyl lead			

^a Conversion from other units assumed 0.75 specific gravity.

^b Compounds for which AALs are being developed.

^c ASTM specification, maximum, unleaded gasoline, 0.013 g/l maximum, conventional grade gasoline, 1.1 g/l. Title 13, CAC, Section 2253.2, maximum, leaded gasoline other than leaded high octane gasoline, 0.8 g/gallon maximum, leaded high octane gasoline, 1.0 g/gallon. Federal standards, January 1, 1986, maximum, 0.1 g/gallon.

^d ASTM maximum, unleaded gasoline, 0.10 by percent weight. Conventional grade gasoline, 0.15 by percent weight, Title 13, CAC, Section 2252, maximum 300 ppm by weight.

REFERENCES

1. American Petroleum Institute, 1985. *Cadmium: Environmental and Community Health Impact*. Washington, D.C. EA Report API 137C.
2. American Petroleum Institute, 1985. *Vanadium: Environmental and Community Health Impact*. Washington, D.C. EA Report API 37D.
3. C. Block and R. Dams, 1978. Concentration Data of Elements in Liquid Fuel Oils as Obtained by Neutron Activation Analysis. *Journal of Radioanalytical Chemistry* 46:137-144.
4. Clifford J. Bruell and George E. Hoag, 1984. Capillary and Packed Column Gas Chromatography of Gasoline Hydrocarbons and EDB. *Proceedings of the NWWA/API Conference on Petroleum Hydrocarbons and Organic Chemicals in Ground Water: Prevention, Detection, and Restoration*. NWWA, Worthington, Ohio, pp. 234-266.
5. W. Emile Coleman, Jean W. Munch, Robert P. Streicher, H. Paul Ringhand, and Frederick C. Kopfler, 1984. The Identification and Measurement of Components in Gasoline, Kerosene, and No. 2 Fuel Oil that Partition into the Aqueous Phase After Mixing. *Arch. Environ. Contam. Toxicol.* 13:171-178.
6. George P. Gross, 1971. *Gasoline Composition and Vehicle Exhaust Gas Polynuclear Aromatic Content*. Esso Research and Engineering Co., Linden, N.J., 124 p. PB 200 266.
7. Harold E. Guard, James Ng, and Roy B. Louglin, Jr., 1983. *Characterization of Gasolines, Diesel Fuels, and Their Water Soluble Fractions*. Naval Biosciences Laboratory, Oakland, CA, September 1983.
8. H.J. McDermott and S.E. Killiany, 1978. Quest for a Gasoline TLV. *Am. Ind. Hyg. Assoc. J.* 39:110-117.
9. National Research Council, 1981. *The Alkyl Benzenes*. National Academy Press, Washington, D.C.
10. W.N. Sanders and J.B. Maynard, 1968. Capillary Gas Chromatographic Method for Determining the C3-C12 Hydrocarbons in Full-Range Motor Gasolines. *Analytical Chemistry* 40(3):527-535.
11. Mark E. Myers, Jr., Janis Stollsteiner, and Andrew M. Wims, 1975. Determination of Hydrocarbon-Type Distribution and Hydrogen/Carbon Ratio of Gasolines by Nuclear Magnetic Resonance Spectrometry. *Analytical Chemistry* 47(12):2010-2015.
12. L.L. Stavinoha and F.M. Newman, 1972. The Isolation and Determination of Aromatics in Gasoline by Gas Chromatography. *Journal of Chromatographic Science* 10(9):583-589.

ATTACHMENT 1.4-2

OTHER CHARACTERISTICS OF REFINED PETROLEUM PRODUCTS

MOTOR GASOLINES

Motor gasolines are a complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, that have been blended to yield a fuel suitable for use in spark-ignition engines. Specifications for motor gasoline, as given in ASTM Specification D 439 or Federal Specification VV-G-1690C, include a boiling range of 122° to 158°F at the 10% point to 365° to 374°F at the 90% point and a Reid vapor pressure range from 9 to 15 psi. "Motor gasoline" includes finished leaded gasoline, finished unleaded gasoline, and gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasohol is also excluded.

Leaded Regular Gasoline

As defined in ASTM D 439 and EPA Specifications, gasoline anti-knock designation 3 produced with the use of any lead additives or that contains more than 0.05 grams (g) of lead per gallon or more than 0.005 g of phosphorus.

Unleaded Regular Gasoline

As defined in ASTM D 439 and EPA Specifications, gasoline anti-knock designation 2 containing not more than 0.05 g of lead per gallon and not more than 0.005 g of phosphorus.

Leaded Premium Gasoline

As defined in ASTM D 439 and EPA Specifications, gasoline anti-knock designation 5 produced with the use of any lead additives or that contains more than 0.05 g of lead per gallon or more than 0.005 g of phosphorus.

Unleaded Premium Gasoline

As defined in ASTM D 439 and EPA Specifications, gasoline anti-knock designation 4 containing not more than 0.05 g of lead per gallon and not more than 0.005 g of phosphorus.

Gasohol

A blend of finished motor gasoline (leaded or unleaded) and alcohol (generally ethanol but sometimes methanol) in which 10 percent or more of the product is alcohol.

AVIATION GASOLINES

All special grades of gasoline for use in aviation reciprocating engines, as given in ASTM specification D 910 and military Specification MIL-G-5572. Specifications for aviation gasoline in ASTM specification D 910 include a boiling range of 167°F at the 10% point to 275°F at the 90% point and a Reid vapor pressure range of 5.5 to 7.0 psi. Excludes blending components that will be used in blending or compounding into finished aviation gasoline. Three grades of aviation gasoline are known as: Grade 80-red, Grade 100-green, and Grade 100-LL-blue.

Grade 80

As defined in ASTM D 910, an aviation gasoline with an octane value of 80. It is colored red if it contains 0.5 mg of lead per gallon.

Grade 100

As defined in ASTM D 910, an aviation gasoline with an octane value of 100 and containing a maximum of 4 mg of lead per gallon. It is colored green to distinguish it from the grade 100-LL, which is the same fuel but with a lower lead content.

Grade 100-LL

As defined in ASTM D 910, an aviation gasoline with an octane value of 100 and containing a maximum of 2 mg of lead per gallon. It is colored blue to distinguish it from the grade 100, which is the same fuel but with a higher lead content.

AVIATION TURBINE FUELS

A quality kerosene product with an average gravity of 40.7° API, and a 10% distillation temperature of 400°F. It is covered by ASTM Specification D 1655 and Military Specification MIL-T-5624L (Grades JP-5 and JP-8). See also Exhibit 1.4-29.

Jet A

A relatively high flood point distillate of the kerosene type with a maximum freezing point of -40°Centigrade.

Jet A-1

Same as Jet A but with a maximum freezing point of -47°C.

Jet B

Jet B is a relatively wide boiling range volatile distillate. A relatively low freezing point distillate of the kerosene type, it is used primarily for commercial turbojet and turboprop aircraft engines.

JP-5

A mixture of special kerosene and aviation gasoline specially designed for Navy carrier operations.

JP-8

A kerosene-type, high-flash-point fuel similar to the jet fuel JP-4, developed for British and European military planes. The U.S. military is converting some places from JP-4 to JP-8 to reduce vapor losses at the high temperatures produced by supersonic aircraft. Current use of JP-8 within the United States is very limited.

NAPHTHA-TYPE JET FUEL: JP-4

A fuel in the heavy naphtha boiling range with an average gravity of 52.8°F API and up to 90% distillation temperatures of 290° to 470°F, meeting Military Specification MIL-T-5624L (Grade JP-4). It is a blend of 25-35% kerosene and 65-75% gasoline. JP-4 is used for turbojet and turboprop aircraft engines, primarily by the military. See also Exhibit 1.4-29.

DISTILLATE FUEL OILS

A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, as fuel for on- and off-highway diesel engines (including railroad locomotive engines and agricultural machinery engines), and for electric power generation. See also Exhibit 1.4-29.

No. 1 - D (Diesel)

A volatile distillate fuel oil (from kerosene to the intermediate distillates) with a boiling range between 300° and 375°F and used in high-speed diesel engines generally operated under varying in speed and load conditions. Includes type C-B diesel fuel used for city buses and similar operations. Properties are defined in ASTM Specification D 975.

No. 1

A light distillate fuel oil (a little heavier than kerosene, but lighter than No. 2 oil) intended for use in vaporizing pot-type burners. ASTM Specification D 396 specifies this grade maximum distillation temperatures of 420°F at the 10% point and 550°F at the 90% point, and kinematic viscosities (see Exhibit 1.4-30 for kinematic viscosities of gasoline, kerosene, and fuel oils) between 1.4 and 2.2 mm²/sec, or centistokes (CST), at 100°F. No. 1 oil is a colorless to light brown liquid known commonly as kerosene or range oil.

No. 2-D (Diesel)

A gas or oil type distillate of lower volatility with distillation temperatures at the 90% point between 540° and 640°F for use in high-speed diesel engines generally operated under uniform speed and load conditions. Includes Type R-R diesel fuel used for railroad locomotive engines, and Type T-T for diesel-engine trucks and tractors. No. 2 diesel fuel is also used in agricultural machinery and in marine vehicles. Properties are defined in ASTM Specification D 975.

No. 2

A distillate fuel oil (a light brown liquid with an odor like kerosene) for use in atomizing type burners for domestic heating or for moderate capacity commercial-industry burner units. ASTM Specification D 396 specifies for this grade distillation temperatures at the 90% point between 540° and 640°F, and kinematic viscosities between 2.0 and 3.6 CST at 100°F.

RESIDUAL FUEL OILS

See also Exhibit 1.4-29.

No. 4-D (Diesel)

A fuel oil used in low and medium speed engines operating under sustained loads and nearly constant speeds. These engines can be either compression or ignition type.

No. 4 Light

A fuel oil for commercial burner installations not equipped with preheating facilities. It is used extensively in industrial plants. This grade is a blend of distillate fuel oil and residual fuel oil stocks that conforms to ASTM Specification D 396 of Federal Specification VV-F-815C; its kinematic viscosity is between 2.0 and 5.8 CST at 100°F.

No. 4

A fuel oil (a brownish liquid with a characteristic fuel oil or kerosene odor) for commercial burner installations not equipped with preheating facilities. It ranges from a light distillate type, low viscosity fuel to heavier residual type fuel oil, depending on the burner. It is used extensively in small boilers in schools, apartment buildings, and industrial plants. This grade is a blend of distillate fuel oil and residual fuel oil stocks blended to the viscosity needs of the burner. It is rarely used in the United States.

No. 5 Light

A residual fuel (a brownish liquid with a kerosene odor) with as high a viscosity as can be handled and burned without preheating. It is seldom produced in refineries but is made by diluting No. 6 fuel oil with distillate oils to meet certain viscosity specifications of the buyer. It also has a higher ash content than the lighter fuel oils. It is commonly used by burners capable of handling fuels more viscous than grade No. 4.

No. 5 Heavy

A heavy residual fuel (a brownish liquid with a kerosene odor) produced by diluting No. 6 fuel oil with distillate oils to lower its viscosity to meet the specifications of the burner. Like No. 5-Light, it too has a higher ash content, which means it produces more residue when burned. It is generally used in small installations with medium rates of consumption and equipped with preheaters. In cold climates, preheating also may be required for handling.

No. 6 (Bunker C)

The residual oil that is left when light oils, gasoline naphtha, kerosene, and distillate oils are extracted from crude at normal temperatures and pressure. It is a thick, dark brown, semifluid material that requires heating for handling. It requires burners with preheaters and is used for commercial and industrial heating by facilities with heated equipment for proper handling. It is frequently used to power large ships and is known as Bunker C in this application.

GAS-TURBINE FUEL OILS

This is a general classification for various grades of fuels used in gas turbines. Heavier grades (such as grade 4-GT) are not suited for aircraft use. Properties are defined in ASTM Specification D 2880-80.

Grade O-GT

A product of naphthas and low flash distillates, Grade O-GT is used in gas turbines that require clean-burning fuels. It has a very low flash point and ash content. Includes naphtha, Jet B fuel, and other volatile hydrocarbon liquids.

Grade 1-GT

Grade 1-GT is made from light distillates, which include gas oil fractions. It can be used in nearly all gas turbines. The minimum flash point of Grade 1-GT is 38°C (100°F), and 90% distills at a maximum temperature of 288°C (550°F). Corresponds to No. 1 fuel oil and No. 1.4 diesel fuel in general physical properties.

Grade 2-GT

This fuel oil is similar to No. 2 distillate fuel oil, as it includes heavier distillates than Grade 1-GT. Its primary application is for gas turbines requiring a fuel with low ash characteristics (0.10 percent), but not necessarily as clean burning as Grade 1-GT. Grade 2-GT has a minimum flash point of 38°C (100°F) and a 90% distillation point from 282° to 338°C (540° to 640°F). Corresponds in general to No. 2 fuel oil and No. 2-D fuel oil in physical properties.

Grade 3-GT (Residual)

This is a heavier grade compared to the gas turbine oils described above, but also has a low ash content when burned. It is used for gas turbines that often require fuel heating equipment and whose inlet temperatures are below 605°C (1202°F). Grade 3-GT has a minimum flash point of 55°C (131°F) and a minimum kinematic viscosity of 5.5 CST.

Grade 4-GT (Residual)

This grade is somewhat similar to Grade 3-GT (above), but this fuel is used in gas turbines that can use fuels with less severe restrictions on ash content. Grade 4-GT has a minimum flash point of 66°C (151°F).

ILLUMINATING OILS

Kerosene

Kerosene is a petroleum distillate that boils at a temperature between 300° and 500°F, has a flash point higher than 100°F by ASTM Method D 56, has a gravity range from 40° to 46° API, and has a burning point in the range of 150° to 175°F. Color ranges from colorless to light brown. Included are the two classifications recognized by ASTM Specification D 3699-83, No. 1-K (low sulfur grade) and No. 2-K (regular grade), and all grades of kerosene called range or stove oil that have properties similar to No. 1 fuel oils, except their gravity is about 43° API and their maximum endpoint is 625°F. Kerosene is used in space heaters, cook stoves, and water heaters and is suitable for use as an illuminant when burned in wick lamps.

Mineral Seal Oil, Other Long-Burning Oils, 300 Oil, Mineral Colza Oil

Mineral Seal oil, long-time burning oils, 300 oil, and mineral colza oil are straight-run (non-cracked) treated distillates from paraffinic or mixed-based crudes. These types of oils are used in applications where prolonged burning is required.

IX. SOLVENTS

Most hydrocarbon solvents are straight-run naphthas from paraffinic or mixed-based crudes. Aromatic solvents are derived from petroleum aromatics (via aromatization processes) and must be in a specific boiling range.

Stoddard Solvent - Type I Solvent

Stoddard solvent is a commercial reference for Type I dry-cleaning solvent. It is chemically treated straight-run naphtha made from paraffin-based or mixed-base crude oils. Stoddard solvent has a minimum flash point of 38°C (100°F) and a maximum dry point (distillation) of 208°C (406°F). Specifications are listed in ASTM D 235.

Petroleum Spirits, Minerals Spirits, Petroleum Ether-Types II, III, IV Solvents

These solvents are made in a similar fashion to Stoddard solvent and are used as paint varnish and thinners. They are mostly aliphatic petroleum fractions with a boiling point of 90° to 150°C (194° to 302°F) and have properties similar to dry cleaning solvents Types I-IV (i.w., low flash point, colorless liquids). (Specifications for Types I-IV dry cleaning solvents are published in ASTM D 235, ASTM D 86.) Distillation dry points (point at which all liquid evaporates) are in the 185° to 212°C (365° to 414°F) range.

Varnish Makers' and Painters' (VM&P) Naphthas, Type I, II, III Solvents

These solvents, also known as VM&P naphthas, are very similar to the previous solvents and are used as thinners in paints, varnishes, and coatings. They too are grouped into types based on physical properties. Type I is the regular VM&P naphthas, Type II has a higher flash point, and Type III is odorless. VM&P naphthas are defined in ASTM specification D 3735.

Petroleum Extender Oils - Types 101, 102, 103, 104

Petroleum extender oils are naphthas from paraffin-based crudes used in processing rubber products. The four varieties, Types 101-104, range in asphaltene content from 0.75% to 0.1%, polar composition from 25% to 1%, and saturated hydrocarbon composition from 20% to 65%. (Asphaltene is an asphalt constituent, which is soluble in carbon disulfide but not in paraffin naphthas and consists of polynuclear hydrocarbons joined by alkyl chains.) Specifications for extender oils are listed in ASTM D 2226-82.

Commercial Hexane

A solvent composed of n-hexane plus varying amounts of related isohexane compounds, depending on the initial crude oil stock used in the distillation process. Primary commercial uses are in the production of gasoline, as the solvent for extracting oils from seed crops and reaction mediums for various polymerization reactions. Commercial hexanes are also used in the manufacture of quick-drying adhesives, lacquers, and printing inks.

LUBRICANTS

Lubricants are generally petroleum products designed to protect moving machine parts from friction, heat, and wear. The various lubricants used can be classified broadly as automotive or industrial, depending on the type of machinery the lubricant is used on.

Automotive Lubricants

Automotive lubricants are used in cars, trucks, tractors, and other motor vehicles. The lubricants themselves are either viscous liquids (such as motor oil) or semi-solid (such as bearing grease). Some motor oil products are also synthetically derived petrochemicals but serve the same lubrication function. Specifications for automotive lubricants are listed by Society of Automotive Engineers (SAE) or American Petroleum Institute (API) standards.

Crankcase Oils

Crankcase oils, known commonly as "motor oil," are made from fractionated and refined paraffin-based, mixed-base, or cycloparaffin-based crudes. They may also be produced from solvent-refined mixed-based crudes. Motor oils often contain various additives, including anti-oxidants, detergents, and viscosity builders. Commercial oils are labeled with the specifications and weights to which they conform.

Transmission and Axle Lubricants

Transmission and axle lubricants are made from well-refined heavy oils and contain various additives to improve film strength or high-pressure performance. Some of these fluids are made for closed systems to last the lifetime of the vehicles.

Industrial Lubricants

Industrial lubricants are used in large industrial machines, steam-turbines, compressors, and gears. Many are products of paraffin-based oils but may also come from other crudes; almost all contain additives. Their viscosities are often measured in Saybolt Universal seconds (SUs), which are derived from viscosity measurements in centistokes (based on temperature).

Machine and Engine Oils

These oils are of medium viscosity and are made from paraffin-naphthene-, or mixed-based crudes -- the same base as for crankcase oils. As indicated above, they may contain additives, depending on the specific application.

Steam-Turbine Oils

These oils are used as lubricants, coolants, and corrosion inhibitors in steam turbines. Like machine oils, they are made from paraffin-based or mixed-based crudes, but they are more highly refined (or solvent-treated). The viscosity is in the range of 150-450 SUs (32-97 CST).

Steam-Engine and Cylinder Oils

Steam engine oils are used as lubricants and sealing fluids in the cylinders of these engines. They are of high viscosity and are mostly paraffin-based. When used with saturated or set steam systems, these oils have 2-5% fat as an additive.

Textile-Machinery Oil

These oils are used in textile machines, mostly for lubrication, cooling, and corrosion prevention of high-speed parts. They are made from paraffin-based or solvent-refined oils and sometimes have rust-preventive additives. Viscosity is in the 60-200 SUs (10-43 CST) range.

Refrigerating-Machine Oils

These oils are wax-free oils of medium viscosity (similar to steam-turbine oils) used in refrigerating machines. They must be able to withstand direct contact with fluorocarbon or ammonia refrigerants.

Gear Oils

A great variety of gear oils exist, ranging from light-colored, highly refined, low viscosity (90-150 SUs or 18-32 CST) oils to black, residual oils that contain volatile components. Depending on the gear application, they may contain film-strength improvers or additives to improve performance under high pressure.

BUILDING MATERIALS

Many of these materials come from refinery bottoms or residual oils. A large number of them are solid or semi-solid. Only those materials that are liquids at standard temperature and pressure, however, are discussed below.

Liquid Asphalt (Cutback Asphalt)

This type of asphalt is made from residual materials from vacuum distillation (especially from asphalt-based crudes), but it is "cut back" with naphtha (for rapid-curing) or kerosene (medium-curing). Liquid asphalt is useful as a binder in road surface treatment, cold patching, or cold-weather construction of macadam surfaces.

Dust-Laying Oils

Unlike other petroleum product building materials, dust-laying oils are low viscosity materials. These oils are made from untreated distillates or lighter-grade fuel oils.

INSULATING AND WATER PROOFING MATERIALS

Transformer Oils

Transformer oils serve as electrical insulators and coolants for oil-filled transformers, circuit breakers, and switch boxes. They have generally been made from cycloparaffinic bases but more recently have been made from paraffinic bases. Polychlorinated biphenyl additives have been eliminated from transformer oil manufacture but may still be found in transformer oils that have been in use for some time.

Cable Oils

Cable oils are composed of conventionally refined naphthene oils. Lighter grades are used in oil-filled cables, while heavier grades are applied to paper-wrapped cables. They are also used for thermal and electrical insulation.

OTHER PETROLEUM SUBSTANCES

Crude Oils

A naturally occurring mixture, predominantly hydrocarbon with sulphur, nitrogen, and/or oxygen derivatives, which is found in natural underground reservoirs in liquid phase and which remains liquid at atmospheric pressure after passing through surface operating facilities. Crude oil includes condensate and liquid hydrocarbons produced from tar sands, gilsonite, and oil shale. Drip gases are also included, but topped crude oil (residual oil) and other unfinished oils are excluded. Liquids produced at natural gas processing plants and mixed with crude oil are likewise excluded.

Crude Oil Fractions

Streams or fractions into which crude oil has been separated without being otherwise modified.

Petroleum Feedstocks

Products from the refinery process, prior to conversion or upgrading, from which gasoline, fuel oil, and petrochemicals are produced by thermal or catalytic cracking. Petroleum feedstocks commonly include benzene, toluene, xylene, naphtha, and gas oils.

Petroleum Fractions

Products or mixtures of products from the refinery distillation process that are characterized by similar properties, particularly boiling ranges. The most important petroleum fractions are naphtha, kerosene, fuel oil, and tarry or waxy residues. Same as crude oil fractions if hydrocarbon source is crude oil.

Used Oil

A petroleum-derived or synthetic oil, including, but not limited to, oil that was used in one of the following applications:

- (1) as a lubricant (engine, turbine or gear);
- (2) as a hydraulic fluid (including transmission fluid);
- (3) as a metal working fluid (including cutting, grinding, machining, rolling, stamping, quenching, and coating oil); or
- (4) as a coolant that is contaminated through use or subsequent management.

Waste Oil

Waste oil is defined as that portion of used oil that is bound for disposal rather than recycling.

Exhibit 1.4-29

**Physical/Chemical Data for
Various Petroleum Products**

Product	Physical Description	Flash Point	Auto-Ignition Temperature	Density Range	Explosion Limits of Vapor (in air)	Vapor Density	Pour Point	Average Boiling Range	Composition	ASTM Definition
JP-1		95 to 145EF (35 to 63EC)	44EF (6.7EC)							
JP-4		-10 to 30EF (-23 to -1EC)	468EF (242EC)						65% gasoline, 35% light petroleum distillate.	
JP-5		95 to 145EF (35 to 63EC)	475EF (246EC)						Specifically refined kerosene.	
JP-6		100EF (38EC)	435EF (224EC)						A higher kerosene cut than JP-4 with fewer impurities.	
Fuel Oil #1 (Kerosene)	A pale yellow or clear oily liquid	100 to 165EF (38 to 74EC)	444EF (229EC)	0.80 to 0.875 6.879 to 7.085 lb/gal	Upper: 5.0% Lower: 0.7%	4.5 times that of air	0EF (-18EC)	345 to 510EF (174 to 266EC)	A complex mixture of hydrocarbons, usually containing 10 to 16 carbon atoms per molecule. Chemical composition by percent is: alkanes, 30%; cyclic alkanes, 60%; and aromatics, 10%.	A light distillate intended for use in business of the vaporizing type in which the oil is converted to vapor by contact with a heated surface or by radiation. High volatility is necessary to ensure that evaporation yields minimal residue.
Fuel Oil #2 ^a (Diesel)	A yellow viscous liquid	100EF (38EC)	494EF (257EC)	0.825 to 0.925 7.128 to 7.490 lb/gal			20EF (-7EC)	93 to 365EF (34 to 185EC)	A complex mixture of hydrocarbons with 12 to 20 carbon atoms per molecule. Average chemical composition by percent is: alkanes, 30%; cyclic alkanes, 45%; aromatics, 25%.	A heavier distillate than Fuel Oil #1, it is intended for use in atomizing type burners that spray the oil into a combustion chamber where tiny droplets burn while in suspension. This grade of oil is used in most domestic burners and in many medium capacity commercial-industrial burners.

**Various Petroleum Products
(continued)**

Product	Physical Description	Flash Point	Auto-Ignition Temperature	Density Range	Explosion Limits of Vapor (in air)	Vapor Density	Pour Point	Average Boiling Range	Composition	ASTM Definition
Fuel Oil #4	Can be prepared by combining 40% fuel oil #6, or may be a high-boiling distillate or light residual of the crude oil.	130EF (54EC)	505EF (263EC)	7.538 to 7.587 lb/gal				20EF (-7EC)		Fuel oil #4 is intended for use in burners that atomize oils of higher viscosity than domestic burners can handle. Its permissible viscosity ranges allow it to be pumped and atomized at relatively low storage temperatures. Thus, in all but extremely cold weather, it requires no preheating for handling.
Fuel Oil #5 (Navy Special or Bunker "B")	May be prepared by combining 20-25% fuel Oil #2 with 75-80% Fuel Oil #6	Over 130EF (over 54EC)		7.686 to 7.891 lb/gal						Light: a residual oil of intermediate viscosity for burners capable of handling fuel more viscous than Fuel Oil #4 without preheating. Preheating may be necessary in some types of equipment and in colder climates. Heavy: a residual fuel oil more viscous than No. 5 light and intended for use in similar service. Preheating to 170E to 220EF (77 to 104EC) is recommended.
Fuel Oil #6 (Bunker "C")	Very viscous, dark-colored liquid	Above 150EF (66EC)	765EF (407EC)	7.998 to 8.108 lb/gal				<u>Low</u> pour: 60EF maximum <u>high</u> pour: no maximum	A complex mixture of heavy molecular weight hydrocarbons. Average chemical composition is: alkanes, 25%; polar compounds, 15%; aromatics, 25%; cyclic alkanes, 45%.	A high viscosity oil used mostly in commercial and industrial heating, Fuel Oil #6 requires preheating to 220E to 260EF (104E to 127EC) to permit pumping and atomizing. The additional equipment and maintenance required to handle this fuel usually precludes its use at small facilities.

^aTypes of No. 2 Fuel Oil include No. 1-D (a volatile distillate for engines in service requiring frequent speed and load changes), No. 2-D (a distillate of lower volatility for engines and heavy mobile service) and No. 4-D (a fuel for low- and medium-speed engines).

Exhibit 1.4-30
Kinematic Viscosity of Petroleum Products

PRODUCT	KINEMATIC VISCOSITY ¹⁷		CENTISTOKES @ 38°C or 40°C
	MIN.	MAX.	
MOTOR GASOLINE	0.5	0.65	NA ⁹
FUEL OIL			
No. 1	1.4	2.2	1.65
No. 2	2.0	3.6	2.97
No. 4-light	2.0	5.8	NA
No. 4-heavy	5.8	26.4	NA
No. 5-light	>26.4	65	NA
No. 5-heavy	>65	194	NA
DIESEL FUEL OIL			
No. 1D	1.3	2.4	1.64
No. 2D	1.9	4.1	1.97
No. 4D	5.5	24.0	NA
GAS TURBINE FUEL OIL			
No. 1-GT	1.3	2.4	NA
No. 2-GT	1.9	4.1	NA
No. 3-GT	5.5	638	NA
No. 4-GT	5.5	638	NA
KEROSENE	1.0	1.9	

NOTE: Adapted from Camp Dresser & McKee Inc. January 1986. Fate and Transport of Substances Leaking from Underground Storage Tanks. Volume 1. Technical Report. Section 5.0. Prepared for the U.S. Environmental Protection Agency, Office of Underground Storage Tanks.

¹⁷ Kinematic viscosity affects the rate at which a petroleum product will leak from a tank and the rate at which it will move through the unsaturated zone. The lower a product's kinematic viscosity, the faster it will move through the subsurface. It is also a temperature-dependent property. Fuel products with a high kinematic viscosity need to be heated if the fuel is to flow freely. The following illustration shows how these products can be grouped according to their kinematic viscosity and vapor pressures.

Low Kinematic Viscosity (Fastest movers)	Motor gasoline Aviation gasoline VM&P Napthas (all types) Aromatic Napthas (Type I & II) Gas turbine fuel oil #0-GT Petroleum spirits (all types)	High Vapor Pressure (most vapor released)
/	/	/
/	/	/
/	/	/
/	Jet fuels A, A-1, & B	/
/	Kerosene 1K & 2K	/
/	Fuel oil #1	/
/	Diesel Fuel #1D	/
/	Gas turbine fuel oil #1-GT	/
/	/	/
/	Fuel Oils #2 & #4	/
/	Diesel Fuels #2D & #4D	/
/	Gas turbine fuel oil #2-GT	/
/	/	/
High Kinematic Viscosity (Slowest movers)	Fuel Oils #5 & #6 Gas Turbine Oils #3-GT & #4-GT Lubricating Oils (Least vapor released)	Low Vapor Pressure

Data is in centistokes (1 centistoke = 1 centimeter²/second).

⁹ Data is not available

ATTACHMENT 1.4-3
SAMPLE WORKSHEETS FOR ORGANIZING
SITE INVESTIGATION INFORMATION

SITE INSPECTION AND HISTORY WORKSHEET

Spill Number: _____
Date of Investigation: _____
Investigator Name: _____
Name of Owner: _____

Name of facility: _____

Location (may include address and legal description):

Location of tank(s) (attach reference, schematic drawing, etc.):

Type(s) of fuel:

Tank description:
_____ (volume, gal.) _____ (material of construction)

Tank test results (recorded/measured leakage rate; may want to append results):

Date of tank test: _____
Test method: _____

Inventory loss (period of record; percent loss; volume unaccounted for, if available):

Failure/discharge (circle):
(A) Catastrophic Loss
(B) Long-term leakage
(C) Overtopping
(D) Unknown
(E) Other

If "Other," describe:

Location(s) of failure(s) (circle):
(A) Tank
(B) Lines
(C) Connections
(D) Other
(E) Undetermined

SITE INSPECTION AND HISTORY WORKSHEET
(continued)

Please describe briefly (for example, "...hole in side of tank from corrosion," or "...crack at union of tank and discharge line"):

Age of tank(s) (if available):
Date of tank installation:

Name of installer:

History of previous tankage on site (that is, could previous tank have also contributed to the problem?):

History of other tanks in area or on site:

Reports of nuisance odors: Yes No

If "Yes," describe and give detail as to how nuisance odors were investigated, with particular emphasis as to how fire/explosion potential was investigated and/or mitigated:

Nuisance odors (how handled if reported):

Fire and explosion potential (how evaluated and handled):

Has air monitoring occurred? Yes No

Date of qualitative analysis

Conducted by (name, title, agency, or company)

Type of instrument

SITE INSPECTION AND HISTORY WORKSHEET
(continued)

Serial number or manufacturer's identification _____

Calibrated to (compound, i.e., benzene, methane, etc.) _____
Date calibrated _____

Number of background samples taken (locations should be illustrated on schematic drawing, if possible, or otherwise documented) _____

Results of background samples Sample No. Response

_____ average

Qualitative analysis of soil samples from excavation

Sample No. Description* Response

_____ average

* For example, "...from near area of suspected leak, randomly located, visually stained or discolored, etc."

Qualitative analysis Pass Fail
(samples below background) (sample above background)

If "Pass," no further analysis required.

If "Fail," quantitative analysis required.

Has indoor air been sampled? Yes No

If "Yes," present analytical results and procedures per NYSDOH indoor air sampling protocol and compare reported values (at existing or potential points of exposure) with background samples. Note that background levels of ambient air at tank sites often contain fuel constituents of concern. It is important to identify the precise source of

SITE SAMPLING AND QUANTITATIVE ANALYSIS WORKSHEET

Spill Number: _____
Name of Investigator: _____
Date of Events Required: _____

A. Site Drawing

The site drawing should be to scale and more detailed than the drawing recommended under "Site Inspections and History." The drawing should identify boring locations, ground-water monitoring locations, tank and line locations, nearby structures, proximity of underground utilities and conveyances, suspected location(s) of leakage, etc. This drawing will also be used to illustrate the direction of ground-water flow, based on measurements of on-site water levels.

B. Subsurface Investigation

- # Boring and well logs (including description of drilling apparatus) should include all field logs and notes, as well as refined logs.
- # Geologic cross-section(s).
- # Chemical stratigraphy (i.e., pattern of contamination observed in borings and displayed with cross-section).
- # Occurrence of ground water (depth to ground water).

C. Hydrogeologic Setting

Describe/Discuss Setting:

Recharge or discharge zone (if known).

Describe/Discuss:

Agreement/disagreement of subsurface conditions at site with regional setting (i.e., significant subsurface structures and deposits as expected or as not expected).

Describe/Discuss:

Evidence of excessive heterogeneity in subsurface deposits (excessive heterogeneity introduced by fractured rock, coarse sand, and gravel deposits, etc., may necessitate a more conservative investigatory approach).

SITE SAMPLING AND QUANTITATIVE ANALYSIS WORKSHEET
(continued)

Describe/Discuss:

Beneficial use(s) of ground water, including existing water usage and existing (documented) water quality.

D. Soil Sampling

LEVEL IN SOIL (ppm)

Constituent Sample #1 Sample #2 Sample #3 Sample #4 Sample #5

Benzene

Xylene

Toluene

Ethylbenzene

Lead (optional)

TPH

Sample Locations:

1.

2.

3.

4.

5.

SITE SAMPLING AND QUANTITATIVE ANALYSIS WORKSHEET
(continued)

E. Interpretation of Results of Ground Water Analysis

Analytical Results (append, including analytical results for any QA/QC samples collected).

Depth of ground water measured on site? Yes No

If "No," give basis for determining depth to ground water. Also, describe those conditions (i.e., historically documented excessive depth to ground water) or intervening low-permeability strata that were believed to preclude/inhibit migration to ground water, thus reducing the need for determining the actual depth to ground water.

Minimum expected depth to ground water: The minimum expected depth to ground water should be used. This depth may vary from the depth to ground water measured on a given date due to seasonal and long-term fluctuations of the water table. Adjusting the value of depth to ground water is particularly important for those areas where: (1) annual fluctuations in the water table are significant, (2) existing depth to ground water is slight, and (3) existing water levels are measured during the dry season. Historical records and basin studies can aid in determining an appropriate adjustment to the observed depth of ground water.

Direction of ground-water flow: Illustrate on-site drawing, including monitoring locations and relative measured elevations of water surface.

SITE SAMPLING AND QUANTITATIVE ANALYSIS WORKSHEET
(continued)

Analytical Results for Downgradient Water Samples

Constituent	Concentration (ug/l) benzene xylene toluene ethylbenzenes	Reported Detection Limit (ug/l) benzene xylene toluene ethylbenzenes
<hr/>		
Sample No. 1		
No. 2		
No. 3		
No. 4		
No. 5		
<hr/>		

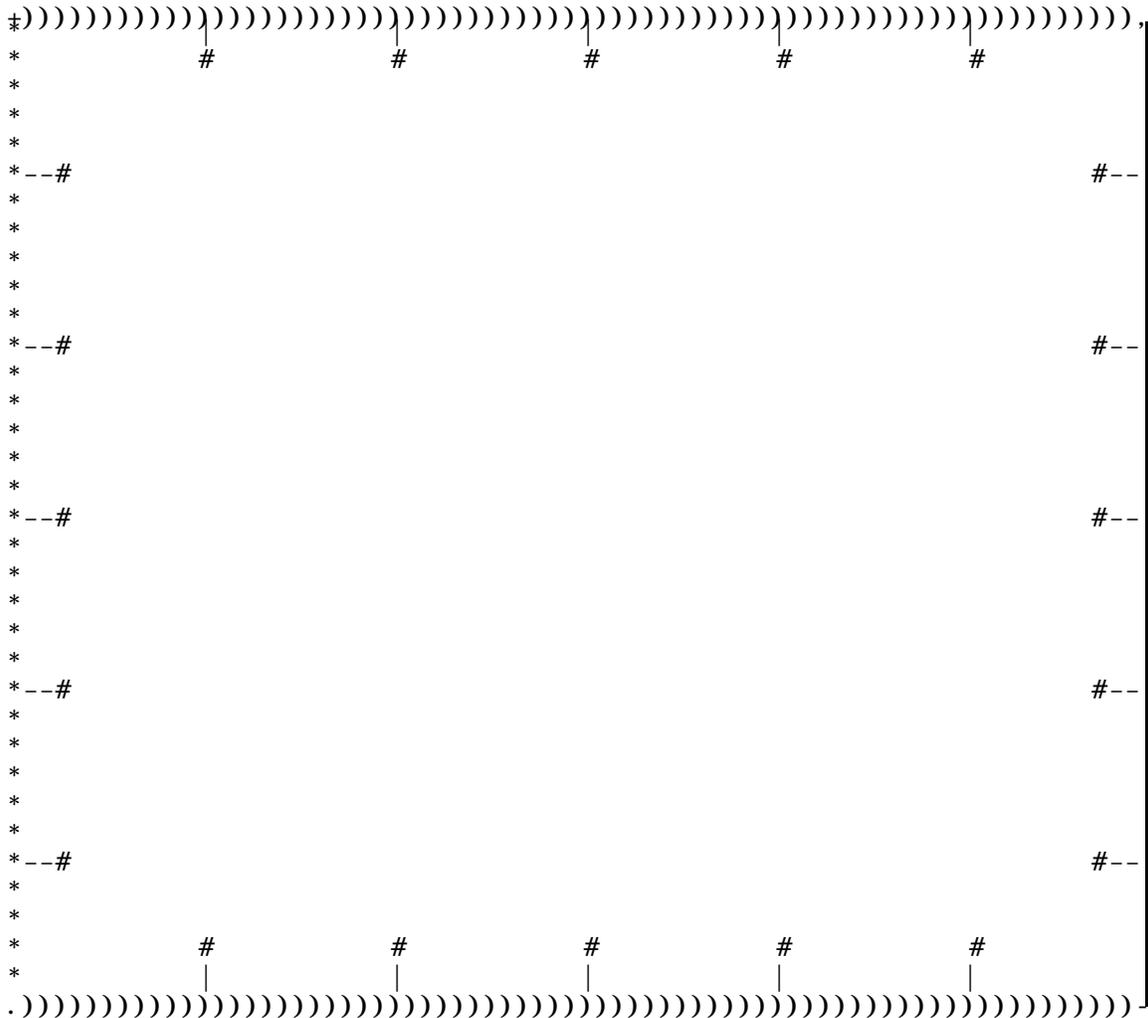
Analytical Results for Upgradient Water Samples

Constituent	Concentration (ug/l) benzene xylene toluene ethylbenzenes	Reported Detection Limit (ug/l) benzene xylene toluene ethylbenzenes
<hr/>		
Sample No. 1		
No. 2		
No. 3		
No. 4		
No. 5		
<hr/>		

Site Drawing

Prepare a drawing of the site showing distances to nearby streams or other surface water, structures, roadways, subsurface utilities, residences, and other surface and subsurface features. Relationship of the tank to permanent objects, such as curbs or buildings, should be shown to facilitate finding the tank or excavation at a later date. Highlight the suspected or known spill source (e.g., tank location). Drawing should be approximately to scale, including distances and directions, as measured, notably the north arrow.

Spill No. _____ PIN: _____
Site Name: _____ Date: _____



Signature: _____