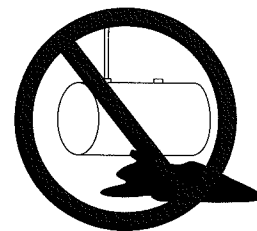


L.U.S.T.LINE

A Report On Federal & State Programs To Control Leaking Underground Storage Tanks



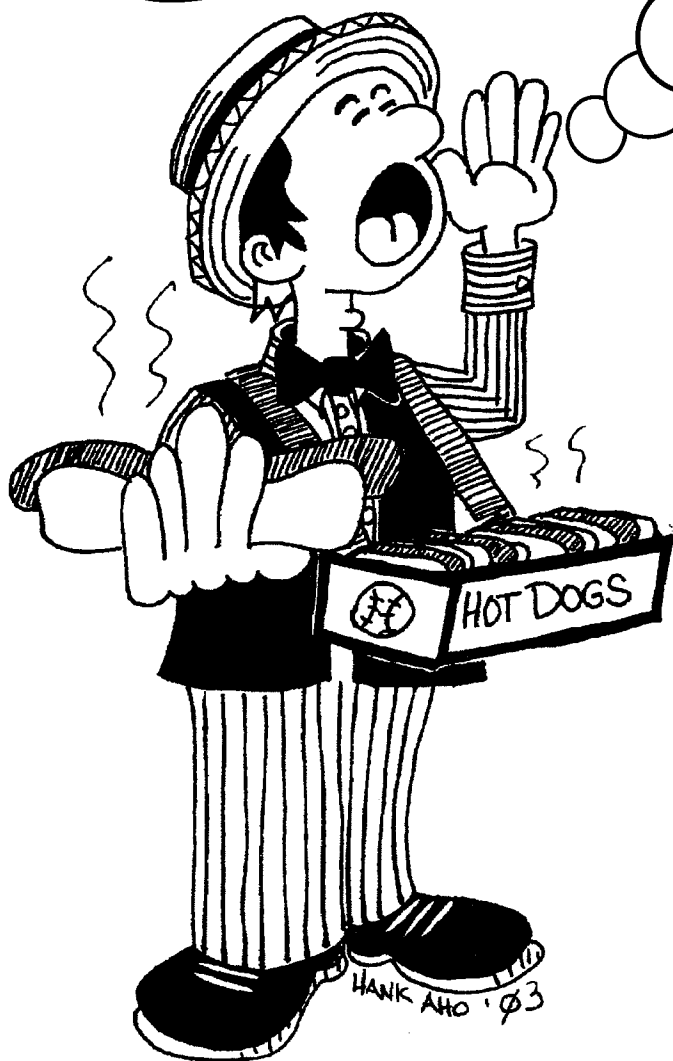
A Hot Dog by Any Other Name Could Be Your Drinking Water

by Patricia Ellis

"Hot dogs, getcher hot dogs!"

The cry of the hot dog vendor at the ballpark. The steaming hot frank with your choice of mustard, ketchup, relish...the captivating aroma and the even more satisfying taste! But let's not stop to think about what's actually in a hot dog. Sure, some of us take comfort in consuming only hot dogs that are "all beef" or "chicken" or Kosher. But what's really in a hot dog? Do we really want to know? And just what has the composition of hot dogs got to do with an article that is ostensibly about leaking underground storage tanks, anyway? Well, it has to do with this propensity to not want to know about those ingredients...even the ingredients in our own drinking water.

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Is Ignorance Bliss?

The drinking water supply systems in the United States are unquestionably the best in the world. Most people can simply turn on the faucet and draw a glass of fresh, clear water that they can put unflinchingly to their lips and drink. Yet, a growing segment of the population uses a filter of some sort, and increasing numbers of people buy bottled water. In fact, in the last 40 years, it is estimated that the U.S. drinking water industry has lost nearly 60 percent of its customers to competitors (currently unregulated) who are "bottled water and point-of-use / point-of-entry providers." (Means et al., 2002) Why?

The reasons are many—taste, odor, color, fad / style, fear (justified or imagined). For those of us on public water supplies, our water suppliers provide us with annual Consumer Confidence Reports (CCRs) that show us that our water has been tested for

a variety of contaminants and is safe to drink. But most water suppliers analyze for a couple dozen contaminants at most. The CCRs tell us whether or not these contaminants were detected and at what concentrations.

When these contaminants are detected, even when their concentration may from time to time exhibit a spike above a regulatory threshold, this water is still distributed to us. Generally an accounting gimmick, such as 30-day average concentration, is employed so that it can be claimed that although detected above the limit, the concentration did not exceed "permissible" levels and the water is safe to drink.

For example, if the analytical report for a sample indicates that each of the BTEX compounds is present but at concentrations below their MCLs (5 ppb, 1,000 ppb, 700 ppb, and 10,000 ppb, respectively), is water with up to 11,705 ppb of BTEX really safe to drink? Do we want to drink it knowing that although the levels are reportedly safe, these contaminants are present at all? Do we want our children drinking it? And, health concerns aside, how does it taste? What about other contaminants that are not on this list of only a couple dozen? Are some of them present and, if so, what do we know about them?

Petroleum Cocktail Hour

Petroleum (and the various fuels distilled from petroleum) is composed of hundreds to thousands of individual organic compounds. (Although this article focuses on gasoline, much of the discussion is applicable to other fuels as well.) "Gasoline" is a complex blend of several hundred hydrocarbons (i.e., compounds that contain only hydrogen and carbon atoms) and other organic compounds that typically contain nitrogen, oxygen, or sulfur. The specific composition of any particular blend of gasoline is a function of the petroleum source, refining and blending processes, and additives (Kreamer and Stetzenbach, 1990). The composition also varies with geographic location and from season to season to maintain performance specifications and comply with regulatory requirements.

The primary groups of hydrocarbons in gasoline are the paraffins, olefins, naphthenes, and aromatics (Youngless et al., 1985). Table 1 lists some representative examples for each of the various classes of these organic compounds. Additive packages (which are generally proprietary) vary considerably and typically include compounds that function as antioxidants, antiicers, metal deactivators, detergents, and corrosion inhibitors, among others (Youngless et al., 1985). Some of these compounds are extremely large, complex molecules.

Some components of gasoline may also contain metal species. The most familiar of these, but not the only ones, are the organic lead compounds, which are no longer used in modern unleaded gasolines. In the past, especially with leaded fuels, a wide variety of dyes were incorporated into gasoline blends as well. Table 2 lists a few of the many gasoline additives.

In addition, a significant number of the compounds in gasoline are *unknown* (or unidentified), except for the number of carbon atoms they contain (Kreamer and Stetzenbach, 1990). What do we know about the toxicity of each of the compounds in gasoline? How do they behave in the environment? Which ones are in our drinking water and at what levels?

For an organic contaminant to show up in a water sample, it must be water soluble. It is well known that aromatic hydrocarbons (of which BTEX is probably the best recognized) are the most soluble constituents of gasoline. Table 3 lists 43 common gasoline constituents with solubility greater than 1 mg/L. Two of the nonaromatic compounds in this table have a higher solubility than ethylbenzene (the "E" in BTEX). This list isn't comprehensive, and there are undoubtedly other compounds with similar properties and, hence, significant water solubility.

While these constituents represent pure compound solubility, and individual solubilities from a mixture would be somewhat lower, the point is that there are lots of soluble constituents in gasoline that can appear in groundwater. If a sample is only analyzed for the aromatic fraction, how do we know that some of these other constituents are not also present?



LUSTLine

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Toxicity of Petroleum Constituents

It should come as no surprise to anyone that exposure (e.g., through inhalation, ingestion, or dermal contact) to any of the constituents of gasoline (or any other fuel) at any concentration should be avoided. Exposure to the vapors from most gasoline constituents can cause dizziness, drowsiness, unconsciousness, and other adverse effects on the central nervous system. Prolonged exposure to low concentrations, or brief exposure to higher concentrations, may damage internal organs, cause cancer or birth defects, or may even be fatal. Ingestion of the liquid phase of neat gasoline (and most, if not all, of its individual constituents) is acutely toxic.

So where do we find information on the toxicity of specific constituents? We would expect that one of the best sources is a material safety data sheet (MSDS), and there are many places to find them on the Internet. But they are readily available only for a small percentage of the constituents of gasoline, and, as they only pertain to exposure to a single compound, the effects of exposure to dilute aqueous mixtures are entirely unknown. (This issue is likely to be one of the important public health challenges of this century, and further discussion is way beyond the scope of this article.)

One of the current ways to deal with a large number of organic compounds is to distribute them into smaller groups, each of which has a designated "surrogate." This is the approach adopted by the Total Petroleum Hydrocarbon Criteria Working Group (TPHCWG). In this method, it is presumed that all members of the group have properties that are similar to the surrogate.

But the approach has several drawbacks. First, compound toxicity isn't necessarily the same for each of the group members, and often the toxic characteristics of a significant proportion of the group are unknown. Second, the presence of the surrogate in a sample may not necessarily mean that there are any other compounds in the sample; if they are, they are probably not at the same concentration. Third, the absence of the surrogate in a sample may not

necessarily mean that all of the other compounds in the class are also absent from the sample. Fourth, many states are statutorily authorized to regulate only those contaminants that appear on EPA's list (i.e., 40 CFR 302.4, discussed in the "Regulation..." section below).

Sadly, the focus on compound toxicity has been so narrowly concentrated on human carcinogenicity that adverse effects other than cancer are usually conveniently ignored. In almost any discussion of risk management, there is no consideration of the teratogenic (birth defect) or mutagenic (mutation) effects of these toxic compounds—not to mention taste or odor!

We have no idea what contaminants are really in the water we drink (or the hot dogs we eat). Simply because a contaminant isn't listed on an analytical report does not mean that the contaminant is not present in the sample. The truth is that we just don't know, but what we don't know can potentially hurt us.

The issue of exposure to multiple toxicants is likewise given short shrift—exposure to multiple toxic compounds is limited to presumed simple additive effects, if it's considered at all. Yet, it is well recognized that the toxicity of a chemical may be increased (or in some cases even decreased) by simultaneous or consecutive exposure to another chemical (Lu, 1991). There is no consideration of synergistic (multiplicative) effects, or whether mixtures may contain procarcinogens, cocarcinogens, or cancer promoters.

And then there's the issue of whether or not a specific compound is a human carcinogen or just an animal carcinogen. Too often an animal carcinogen is touted as being a human noncarcinogen simply because there isn't any confirmation that the compound causes cancer in humans. However, saying that a compound is a noncarcinogen, when the truth is that there isn't enough

information about it to determine whether or not it is a human carcinogen (although the compound is a known animal carcinogen), is being less than honest.

Admittedly, it is difficult (maybe even impossible) to demonstrate with 100 percent certainty that any chemical is a noncarcinogen. But for compounds that are known animal (especially mammalian) carcinogens, ordinary common sense would tell a reasonable person that these are substances with which unnecessary contact should be avoided, even at low concentrations and especially in mixtures that contain substances that may promote cancer.

In theory, a single molecule of a carcinogen can induce cancer. This means that there is no threshold dose and therefore no safe level of exposure to carcinogens. While not all cancer researchers hold this view, the opposing view (i.e., that threshold doses for carcinogens do exist) has yet to be demonstrated, even though large-scale experiments have been conducted for this purpose (Lu, 1991). Further complicating the issue is that unless a fatal quantity of pure product is ingested, most of the toxic effects are slow to develop (10 to 20 years or more in humans) and may be masked by other ailments as we age.

Regulation of Hazardous Substances

Underground storage tanks containing hazardous substances are regulated by the UST program under 40 CFR 280. Additional regulations regarding hazardous substances are found in 40 CFR 302.4 and 40 CFR 261.24. The first of these, CFR 302.4 (U.S. EPA, 2001a), is U.S. EPA's list of approximately 800 Hazardous Substances. Of these substances, only a handful are petroleum hydrocarbons found in fuels, and even fewer are fuel additives. (See Table 4.)

The second regulation, 40 CFR 261.24, is the Toxicity Characteristics (TC) rule for identifying RCRA hazardous wastes. The TC rule specifically exempts "petroleum contaminated" media and debris that fail the test for the toxicity characteristic of 40 CFR 261.24 (U.S. EPA, 2001b). Section 261.24(b) refers to 25 contami-

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nants (but actually lists 26) that are specifically exempt from consideration as "hazardous wastes," provided they are subject to the corrective action regulations under 40 CFR 280 (the UST regulations). This list of 26 contaminants includes benzene and only two additional chemicals (cresol and pyridine) that *may* be present in gasoline or other petroleum fuels.

We all know that none of the components of gasoline (or other petroleum fuels) are healthy for us, so why is it that so few fuel constituents are officially designated as "toxic" or "hazardous"? Part of the answer is that there are simply too many potentially toxic substances to list; some are unidentified, and adequate toxicity testing hasn't been conducted on others. Although not limited to organic compounds, the Chemical Abstract Service (CAS) assigns unique registration numbers (known as CAS or CASRN) to new chemicals at a rate of about 4,000 per day!!! (See <http://www.cas.org/EO/regsys.html>.)

Another part of the answer is that petroleum fuels as a whole are a critical part of the world economy. They've been used for close to 100 years, so we're familiar with them, we need them, and we consider them to be relatively "safe." Perhaps the primary reason why gasoline is considered "safe" is because UST regulations are relatively effective—at least to the extent that there aren't daily media reports of explosions, fires, and underground rivers of gasoline flowing beneath our feet.

However, as we all know, releases from UST systems do happen, sometimes with immediate and catastrophic effect. Every day there are releases of gasoline (and other fuels) into the environment, and a significant amount of the released fuel eventually winds up in groundwater or surface water or both, some of which is used for drinking water. So how do we know what toxic compounds (if any) are actually in our drinking water?

Identification of Toxic Compounds

Let's assume that we have a water sample that may or may not be conta-

minated with one or more of the hundreds of petroleum constituents in gasoline. What tests can we conduct to determine what contaminants are in the sample? Several analytical methods are potentially available to us to determine if any contaminants are present in the sample and at what concentrations. Though not the sole source for analytical methods, EPA's compendium of analytical methods, SW-846, (U.S. EPA, 1997) offers us several choices of determinative analytical methods for organic compounds, including: Methods 8015, 8021, 8260, and 8270. Let's look into each of these in ascending numerical order. (See Table 5.)

■ **Method 8015** (Nonhalogenated Organics Using GC/FID) explicitly lists 30 compounds, of which only four may be present in gasoline. Only one—methanol—is on the list of hazardous substances. This method may also be used for Gasoline Range Organics (GRO) and Diesel Range Organics (DRO), but other methods (which aren't specified in the scope) may be more applicable. No additional guidance is provided regarding GRO or DRO.

■ **Method 8021** (Aromatic and Halogenated Volatiles by Gas Chromatography Using Photoionization and/or Electrolytic Conductivity Detectors) explicitly lists 57 compounds, of which 10 may be present in gasoline and are also on the list of hazardous substances.

■ **Method 8260** (Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry) explicitly lists 107 compounds, of which about a dozen may be found in gasoline and are also on the list of hazardous substances.

■ **Method 8270** (Semivolatile Organic Compounds by Gas Chromatography/Mass Spectrometry) explicitly lists about 250 compounds, of which only a couple are likely to be found in gasoline (although many more could be present in diesel fuel and heavier fuel oils) and are on the list of hazardous substances.

U.S. EPA drinking water methods 502 and 524.2 contain a slightly different list of chemicals.

Of the more than 400 target compounds identified by the four 8000-series methods, approximately 5 percent may be present at any given petroleum release site. "Well and good," you're thinking, "but what's the point of this?"

Absence of Proof Is Not Proof of Absence

Well, the first point of this is that we have no idea what contaminants are really in the water we drink (or the hot dogs we eat). Simply because a contaminant isn't listed on an analytical report does not mean that the contaminant is not present in the sample. (Note that the converse is also true—that is, there is no proof that the contaminant is present.) The truth is that we just don't know, but what we don't know *can* potentially hurt us.

There are a lot of reasons why the presence of a contaminant in a sample might go unrecognized:

- There was no analysis for the contaminant.
- There was an analysis for the contaminant, but an inappropriate method was used.
- The analytical method was applied incorrectly.
- The detection limit is very high.
- Matrix interferences.

In each of these cases, a contaminant could be in a sample, but its presence (and concentration) is undetected (and undetermined). We have to do a better job than we currently do to both anticipate which potential contaminants may be present at a given site and analyze for all of them to determine whether they are in fact present or absent.

In addition to the desirability of knowing all chemicals present for the purpose of conducting a risk assessment, it is important to know all the contaminants present when developing a remediation plan.

In one of my recent projects, carbon filters used as point-of-entry treatment for domestic wells were breaking through in far shorter times than what was expected. After run-

ning Method 8260 plus requesting that all "tics" be identified by a library search, we identified a total of 45 additional chemicals, all potentially having a gasoline source, as being present in the water samples. These additional chemicals all contributed to the loading on the carbon filters and contributed to the early breakthrough. The library search gave estimated concentrations, but none of these compounds had been calibrated against a standard.

I might also have been happier if I hadn't added dissolved lead to the list of analytes because of earlier detections of EDC. Dissolved lead exceeded recommended levels in every sample (pre- and post-carbon filters), and in every well, even where no gasoline components were detected. Further analysis, this time for tetraethyl and tetramethyl lead, the organic lead that would come from leaded gasoline, was negative. Elevated lead levels appeared to be present throughout the aquifer, which would also have to be factored into a risk assessment. While the carbon filters were dealing with the gasoline contamination in the wells, albeit in an expensive manner, the filters had no effect on the dissolved lead.

Further, it isn't enough to have samples analyzed even for all potential contaminants if the samples aren't representative. Samples must be collected from locations where contaminants are most likely to be present, and they must be correctly handled during collection, transport, preparation, and analysis.

Fuel-Specific Analytical Methods

My second point is that the current analytical practices we rely on to determine whether gasoline compounds are present or absent in water (and soil) samples are incomplete and therefore inadequate. Standard operating procedures for Methods 8015, 8021, 8260, and 8270 require calibration for only a few of the many compounds that are present in gasoline, but many compounds are either not present or are unknown.

Target analyte lists must be refined so that they are more representative of the contaminants that are

Table 1 Representative Organic Compounds Found in "Gasoline"

Straight Chain Alkanes propane n-hexane n-dodecane	Cycloalkenes cyclopentene 3-methylcyclopentene
Branched Alkanes isobutane 2,2-dimethylbutane neopentane 3-ethylhexane	Alkyl Benzenes benzene toluene ethylbenzene o-xylene m-xylene p-xylene 1,2-dimethyl-3-ethylbenzene 1,2,3-trimethylbenzene 1,2,4,5-tetramethylbenzene n-propylbenzene
Cycloalkanes cyclohexane n-propylcyclopentane ethylcyclohexane	Other Aromatics indan 1-methylindan phenol
Straight Chain Alkenes cis-2-butene 1-pentene trans-2-heptane	Polycyclic Aromatic Hydrocarbons (PAHs) naphthalene
Branched Alkenes 2-methyl-1-butene 4,4-dimethyl-cis-2-pentene	

Source: Adapted from Cole (1994).

Table 2 Representative Organic Compounds Used as Additives in "Gasoline"

Oxygenates methyl <i>tertiary</i> -butyl ether (MTBE) ethanol ethyl <i>tertiary</i> -butyl ether (ETBE) <i>tertiary</i> -butyl alcohol (TBA) <i>tertiary</i> -amyl ethyl ether (TAEE) diisopropyl ether (DIPE) <i>tertiary</i> -amyl methyl ether (TAME) <i>tertiary</i> -amyl alcohol (TAA) methanol	Corrosion inhibitors carboxylic acids sulfonates amine/alkyl phosphates
Anti-knock compounds tetra-ethyl lead (TEL) tetra-methyl lead (TML) methylcyclopentadienyl manganese tricarbonyl (MMT)	Metal deactivators disalicylidene amines phenolic amines thiourea
Anti-oxidant compounds hindered phenols phenylene diamines aminophenols	Ignition controller additives tri- <i>o</i> -cresol phosphates
Anti-icing compounds isopropyl alcohol amides/amines glycols organophosphate ammonium salts	Detergents aminohydroxyamide alkylphenols imidazolines
	Lead scavengers 1,2-dichloroethane (EDC) 1,2-dibromoethane (EDB)
	Dyes azobenzene-4-azo-2-naphthol benzene-azo-2-naphthol para-diethyl aminoazobenzene 1,4-diisopropylaminoanthraquinone

Source: Adapted from Cummings (1977) and Irwin, et. al. (1997).

likely to be encountered at fuel-release sites. For example, nearly 90 percent of the analytes listed for Method 8021 are halogenated compounds that would *not* be present at fuel-release sites—why should a sample be analyzed for them and *not* for some of the few hundred other

contaminants that may actually be present? If we're going to pay for an analysis for, say, 100 compounds, wouldn't it be more cost-effective if those 100 could be reasonably anticipated to be in the sample?

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And, in order to credibly evaluate the actual risk posed by contaminants in our water, we absolutely *must* know which contaminants are in the water. In a recent series of articles by Uhler and others (2002, 2003), similar suggestions were made. They suggest a suite of 109 target analytes for the analysis of automotive gasoline using a Modified 8260 method. The list contains the PIANO compounds (Paraffins, Isoparaffins, Aromatics, Naphthenes, and Olefins), useful for recognizing peculiarities that might be inherited from refinery processes (including

various major and minor iso-alkanes), and gasoline additives, including the oxygenate additives (alcohols and ethers), lead scavengers (EDC and EDB), and methylcyclopentadienyl manganese tricarbonyl (MMT). Some of this list of compounds can be useful in fingerprinting gasoline for environmental forensic investigations, as well as a basis for conducting a risk assessment.

Just how credible, how "scientifically defensible" is a risk assessment based on omission, neglect, or wishful thinking? To only evaluate the risk posed by some, but not all, contaminants present at a site is like crossing a busy highway but only looking

in one direction as you make the attempt. Sure, you may not get hit by a car coming from the direction in which you're looking, but one from the blind side is likely to spoil your day.

Appropriate analytical method(s) already exist in today's marketplace. All that is lacking are appropriate calibration standards and standard operating procedures that have been optimized for analysis of these target analytes. Once it becomes routine to use these standards, risk assessments could be conducted for the contaminants to which receptors are actually exposed, rather than presumed surrogates. This will go a long way toward bolstering the credibility of risk assessment and restoring confidence in the safety of our drinking water.

Take Me Out to the Ballgame

Alternatively, we could opt to accept the status quo...we can slump down in our bleachers, hot dog in one hand, and glass of water (OK, beer) in the other, and blissfully pass away the time. ■

Pat Ellis is a hydrologist with the Delaware Department of Natural Resources and Environmental Control, Tank Management Branch and served as a member of EPA's Blue Ribbon Panel on MTBE. She is a technical advisor and regular contributor to LUSTLine and can be reached at Patricia.Ellis@state.de.us.

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Table 3
Common Gasoline Constituents
Ranked by Solubility (mg/L)

Benzene	1,780
Toluene	515
o-Xylene	220
cis-2-Pentene	203
Cyclopentane	156
Ethylbenzene	152
1-Pentene	148
3-Methyl-1-butene	130
Indan	100
1-Methyl-4-ethylbenzene	95
1,2,3-Trimethylbenzene	77
1-Methyl-2-ethylbenzene	75
Propane	62
1,2,4-Trimethylbenzene	57
Cyclohexane	55
n-Propylbenzene	52
Isopropylbenzene	50
1,3,5-Trimethylbenzene	50
Isobutane	48.9
Methylcyclopentane	42
Pentane	38.5
Naphthalene	31
1-Methyl-naphthalene	28
2-Methyl-naphthalene	25
2,2-Dimethylbutane	18.4
sec-Butylbenzene	17
Methylcyclohexane	14
Isopentane	13.8
2-Methylpentane	13.8
n-Butylbenzene	13.8
3-Methylpentane	12.8
Isobutylbenzene	10.1
Hexane	9.5
2,3-Dimethylpentane	5.25
1,2,4,5-Tetramethylbenzene	3.48
3-Methylhexane	3.3
n-Heptane	2.93
2-Methylhexane	2.54
2,2,4-Trimethylpentane	2.44
2,3,4-Trimethylpentane	2
1-Nonene	1.12

Source: Adapted from Gustafson et al. (1997).

Table 4
Hazardous Substances Listed in 40 CFR
302.4 That May be Present in "Gasoline"

SUBSTANCE	CASRN
1,2-dibromoethane	106934
1,2-dichloroethane	107062
1,3-pentadiene	504609
benzene	71432
cresols	1319773
ortho-cresol	95487
meta-cresol	108394
para-cresol	106445
cyclohexane	110827
ethylbenzene	100414
methanol	67561
naphthalene	91203
phenol	108952
toluene	108883
xylene	1330207
ortho-xylene	95476
meta-xylene	108383
para-xylene	106423

Source: Adapted from Gustafson et al. (1997).

Table 5
Compounds Present in "Gasoline" That Appear on Target Analyte
Lists for Methods in SW-846

COMPOUND	8015*	8021	8260	8270
diethyl ether	x		x	
ethanol	x		x	
methanol	x		x	
pyridine	x		x	
benzene		x	x	
ethylbenzene		x	x	
naphthalene		x	x	x
toluene		x	x	
xylene		x		
o-xylene		x	x	
m-xylene		x	x	
p-xylene		x	x	
1,2-dibromoethane		x	x	
1,2-dichloroethane		x	x	
tertiary-butyl alcohol			x	
phenol				x

*Method 8015 is also indicated to be applicable for GRO and DRO.

NEIWPCC Survey Paints a Complex Picture of Oxygenates at LUST Sites: Part 1

by Ellen Frye

In 2002, the New England Interstate Water Pollution Control Commission (NEIWPCC) received a grant from the EPA Office of Underground Storage Tanks to develop and conduct a survey of the states, the District of Columbia, and the U.S. territories to determine how MTBE and other oxygenate contamination is affecting state LUST programs and the cleanup of contaminated sites. As it was I who undertook this survey for NEIWPCC, I will construe our findings over a period of two *LUSTline* issues (Parts 1 and 2). A full report along with a compilation of the state answers to each question will be posted on NEIWPCC's Web site at www.NEIWPCC.org.

The 55-question (plus numerous subquestions) "Survey of State Experiences with MTBE and Other Oxygenate Contamination at LUST Sites" focused on the following oxygenates: methyl *tertiary*-butyl ether (MTBE), *tertiary*-butyl alcohol (TBA), ethanol, *tert*-amyl methyl ether (TAME), ethyl *tertiary*-butyl ether (ETBE), and diisopropyl ether (DIPE). This survey is a follow-up to a survey conducted in 2000 by NEIWPCC that focused mostly on state experiences with MTBE at LUST sites. As with the 2000 survey, we received responses from all 50 states—truly a remarkable feat on the part of our LUST program personnel. A heartfelt thanks to all of you. (We had no responses from the territories or D.C.)

Table 1 shows how many states now have some kind of an action level, cleanup level, or drinking water standard for each of the oxygenates of concern. Methanol was added to this list because seven states listed this oxygenate under "other" in the survey.

Table 2, on pages 8 and 9, is an ornate tapestry of state MTBE action levels, cleanup levels, and drinking water standards from both the 2000 and 2003 surveys. The levels are reported in parts per million (ppm) for soils and parts per billion (ppb) for

groundwater. As you can see, while many states have made a shift in levels toward increased protectiveness over the past three years, the shift has not been dramatic. Fifteen states are considering making changes to their levels, primarily to either lower existing MTBE standards or add standards for other oxygenates.

The Frustration Factor

The variability in cleanup, action, or drinking water levels or the absence of said levels continues to reflect back to the failure of U.S. EPA to produce MCLs or at least toxicity data for any of the oxygenates. Some states have moved ahead with adopting action levels or cleanup levels—some very conservative, others less so—grabbing at some aspect of information that is available, such as a reference dose. A number of states have zeroed in on either the earlier EPA advisory of 70 ppb or the more recent advisory of 20 to 40 ppb (take your choice). The enforceability of these levels also varies from state to state.

When I finished compiling all of the state responses to the survey, I sent the information back to the states to ask them to make sure it was correct. One of the changes I received came from LeRoy Feusner, Engineering Supervisor with the Wyoming DEQ LAUST Remediation Program. Since I had mailed out the survey, WDEQ had made several proposed changes to implement levels of fuel oxygenate concentrations in groundwater for adoption into the state's Water Quality Rules and Regulations. In addition to MTBE, they had a proposed standard for TBA, TAME, ETBE, DIPE, and methanol.

I checked in with LeRoy to be sure I understood these changes. I told him I was kind of surprised to see this kind of action coming from out yonder in Wyoming. He said "People out here may be on the conservative side, but they still want to know that their water is safe to drink.

Table 1 Numbers of States with Oxygenate Action Levels, Cleanup Levels, or Drinking Water Standards. (Comparison data for 2000 and 2003 available only for MTBE.)

OXYGENATE	2000	2003	PROPOSED (2003)
MTBE	38	42	1
TBA		7	3
Ethanol		4	
TAME		4	1
ETBE		3	2
DIPE		6	2
Methanol		7	
Other Anything detected would trigger action/ must be reported		3	

"If MTBE is considered by EPA to be a national issue, then it ought to be a national priority," LeRoy noted. "The federal government should give priority to all fuel oxygenates in terms of research. They need to establish a reference dose, a cancer potency factor, or an MCL for all of the oxygenates."

Given the responses we got from the states, I think LeRoy's words speak for many LUST regulators who would like nothing better than some solid information that would give credence to their efforts to protect human health and the environment and "stick," when push comes to shove.

Next Time

Thirty seven state respondents said they consider oxygenates other than MTBE to be a potential or unknown problem, six said it was a current problem, two said it was an impending problem, six said it was not a problem, and one didn't know. (One state split its vote among the choices.) Next issue, we'll see how the states are handling this potential or unknown problem and what they are finding out. In the meantime, you can check out the state responses at the NEIWPCC Web site. States can correct information at any time. ■

Table 2
A Comparison of State MTBE Action and Cleanup Levels for 2000 and 2003 and Drinking Water Standards as of 2003

ACTION LEVEL(S)				CLEANUP LEVEL(S)				DRINKING WATER STANDARD			
	Soil (ppm unless noted)		GW (ppb, unless noted)		Soil (ppm, unless noted)		GW (ppb, unless noted)	Primary (ppb, health-based)	Secondary (ppb, taste & odor)	EPA advisory (20-40 ppb)	State advisory (or other) (ppb)
STATE	2000	2003	2000	2003	2000	2003	2000	2003	2003	2003	2003
Alabama	0.082	0.008	20	20	SS/RB	—	SS/RB	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—	—	—
Arkansas	—	—	—	—	—	—	—	—	—	—	—
Arizona (residential/non-residential)	—	Method reporting level	—	20	—	320/3,300	—	20/94	—	—	35
California	—	—	—	13	—	—	—	—	13	5	X
Colorado	—	—	—	—	—	—	—	—	15	—	—
Connecticut	2	2	100	70	2	2	100	70	—	—	70
Delaware	0.130	0.130	SS	180	SS/RB	SS/RB	SS/RB	SS/RB	10	—	—
Florida	0.2	0.2	50	50	0.2	0.2	50	50	—	—	—
Georgia	—	—	—	—	—	—	—	—	—	—	X
Hawaii (threatened/not threatened DW)	0.005/20	0.005/20	20/202,000	20/202,000	0.005/20	0.005/20	20/202,000	20/202,000	—	—	—
Idaho	0.6	—	variable	—	0.052	SS	52, 261, 511	52	—	—	—
Illinois	—	0.32	—	70	—	0.32	—	70	70	—	35
Indiana (residential/indust.)	Above EQLs	0.35	Above EQLs	Detection limit	0.35	0.35/5.6	45	45/720	—	X Voluntary	Voluntary
Iowa	—	—	—	—	—	—	—	—	—	—	—
Kansas	—	—	20	any	any	—	20	20	any	—	—
Kentucky (DW sources)	—	—	—	50	—	—	—	—	—	—	—
Louisiana	20	20	520	520	RB	RB	RB	RB	—	—	—
Maine	—	—	25	25	—	—	35	35	35	X	35
Maryland	SS	SS	SS	SS	SS	SS	SS	SS	—	—	20
Massachusetts	0.3	0.3	70	70	0.3	0.3	70	70	—	—	70
Michigan (aesthetic/health)	—	0.8	—	40/240	0.8	0.8	40	40	240	40	—
Minnesota	—	—	—	—	—	—	—	—	—	—	70
Mississippi	—	—	—	—	—	—	—	—	—	—	—
Missouri (potable/non-potable)	—	60	—	400	60-280	SS: 60, 140, 280	40/400	<400	20	400	40

SS – Site Specific

RB – Risk Based

LDL – Lab Detection Limit

Table 2 continued
A Comparison of State MTBE Action and Cleanup Levels for 2000 and 2003 and Drinking Water Standards as of 2003

	ACTION LEVEL(S)				CLEANUP LEVEL(S)				DRINKING WATER STANDARD			
	Soil (ppm unless noted)	GW (ppb, unless noted)	2000	2003	Soil (ppm, unless noted)	GW (ppb, unless noted)	2000	2003	Primary (ppb, health-based)	Secondary (ppb, taste & odor)	EPA advisory (20-40 ppb)	State advisory (or other) (ppb)
STATE	2000	2003	2000	2003	2000	2003	2000	2003	2003	2003	2003	2003
Montana	0.1-0.3	—	—	—	—	—	30	30	—	—	—	—
Nebraska	—	SS	—	20 + SS	—	SS	—	SS	—	—	—	—
Nevada (RB)	100	—	20/200	20/200	—	—	—	20/200	—	—	X	—
New Hampshire	—	—	13	—	0.13	0.13	13	—	13	20	—	—
New Jersey	—	—	—	—	3.1	3.1	70	70	70	—	—	—
New Mexico	—	RB	100	100	RB	RB	100	100	—	100	—	—
New York	—	any	—	any	0.2	.12	10	10	50	—	—	—
North Carolina	0.92	0.92	200	200	0.92	0.92 or SS	200	200	—	—	X	200
North Dakota	—	—	—	—	—	—	—	—	—	—	X	—
Ohio (* direct contact pathway)	0.530-3.8 Tier 1	0.530-6.43 Tier 1 130*	40	40 (DW)	0.530-3.8 Tier 1	Tier 2, SS target levels	40	Tier 2, SS target levels	—	—	X	—
Oklahoma	—	—	20	—	—	—	—	—	—	—	—	—
Oregon	0.16	—	20	—	0.16	0.16-319,000 (RB)	20	20/51 X 10 ⁶ (RB)	20	—	X	—
Pennsylvania	—	2	—	20	2	2	20	20	—	—	X	20
Rhode Island (GA/GB)	—	—	20	20	—	—	40/5,000	40	—	—	—	40
South Carolina	—	—	40	40	—	—	SS	40	—	—	—	—
South Dakota	—	—	—	—	—	—	—	—	—	—	X	—
Tennessee	—	—	—	—	—	—	—	—	—	—	—	—
Texas (only for threatened DW well)	—	—	—	—	—	—	—	15	—	15	—	—
Utah	0.3	0.3	200	70	0.3	0.3	70	Tier 1-200 RCL-70	—	—	—	—
Vermont	—	—	40	—	—	—	40	40	40	—	—	—
Virginia	>LDL	>LDL	>LDL	>LDL	SS/RB	—	SS/RB	SS/RB	—	—	—	20
Washington	0.1	—	20	—	0.1	0.1	20	20	—	—	—	—
Wisconsin	any	—	12	12	SS	—	60	12	—	—	—	—
West Virginia (volunteer remediation program)	—	97 (residential)	—	20	—	—	—	—	—	—	—	—
Wyoming	SS	SS	200	40	SS	SS	200	40	—	—	—	—

SS – Site Specific

RB – Risk Based

LDL – Lab Detection Limit

An Overview of Treatment Technologies for MTBE and Alternative Oxygenates in Groundwater

by Craig Adams and Justin Sutherland

Methyl-*tert*-butyl ether (MTBE) is mobile and persistent in the environment due to its relatively low biodegradability, low volatility, and high water solubility. These same properties make MTBE difficult to treat in contaminated groundwater. Alternative fuel oxygenates, including ethyl-*tert*-butyl ether (ETBE), *tert*-amyl methyl ether (TAME), diisopropyl ether (DIPE), *tert*-butyl alcohol (TBA), and ethyl alcohol (EtOH), are also used in con-

A study was conducted at the University of Missouri-Rolla to compare the treatment of MTBE and alternative oxygenates in five different groundwaters using air stripping, granular activated carbon (GAC), and the ultraviolet/peroxide (UV/H₂O₂) and ozone/peroxide (O₃/H₂O₂) advanced oxidation processes. In this study, a technical and economic analysis was conducted to compare the treatments of MTBE itself, while comparative treatment

small-scale column tests), and advanced oxidation systems.

Five different groundwaters that encompassed a wide range of water qualities were examined. (See Table 1.) With one exception, the groundwaters were treated unamended with MTBE or in any other way except for pH adjustment (Sites B–E). For Site A, MTBE or alternative oxygenates were added to the desired concentration.



Figure 1. The mobile experimental water treatment system used to conduct comparative treatment tests.

junction with or instead of MTBE in some gasoline formulations.

The most common technologies used for treatment of MTBE, TBA, and other ether oxygenates, in groundwater include air stripping, granular activated carbon (GAC), advanced oxidation, and membrane treatment. Water quality characteristics such as pH, alkalinity, organic carbon concentration, dissolved solids, and other factors all have the potential to affect the effectiveness of these treatments. Additionally, factors such as the treatment flow rate have the potential to have an impact on process effectiveness and associated costs.

efficiencies were developed for the alternative oxygenates. Funding for this project was provided by the Missouri Department of Natural Resources and the Missouri Petroleum Storage Tank Insurance Fund. (The results and conclusions, however, are the authors' and do not necessarily represent the views of either sponsor.)

Pilot Treatment System

This work was conducted in an experimental water treatment system housed in a 2.2 x 5 meter (internal) trailer. (See Figure 1.) The treatment systems consisted of a pilot-scale packed tower, GAC columns (rapid

Analytical Methods

Analysis of MTBE, alternative oxygenates, and BTEX compounds was conducted using purge and trap, gas chromatography/mass spectrometry (GC/MS) with a Tekmar Dohrmann 3100 sample concentrator and an Agilent 6890/5973 GC/MS. Experimental details can be found elsewhere (Sutherland et al., 2002 and 2003a).

Packed Column Air Stripping

Air stripping has been used for many years to remove a wide range of volatile organic compounds (VOCs) from groundwater and drinking water. Packed towers are the most

Table 1

Water Quality Characteristics of the Five Groundwaters Used in the Treatment Study (Sutherland et al., 2003a)

	GROUNDWATER SITE				
	A	B	C	D	E
Total alkalinity (mg/L as CaCO ₃)	214	152	432	390	106
pH	7.0	7.1	7.6	7.7	7.3
Turbidity (NTU)	0.23	0.47	1.11	0.31	1.73
TDS (ppm)	250	273	424	298	169
COD (mg/L O ₂)†	1	29	61	5	5
Influent MTBE (mg/L)	5.03-5.31‡	0.963-1.26	0.023-0.029	0.198-0.224	0.033-0.039
Influent BTEX (mg/L)	<0.0005	<0.0005	1.28-1.86	0.012-0.115	0.013-0.019

† COD for Site A waters was non-detect. COD was set to the MDL of 1 mg/L for calculational purposes.

‡ Influent MTBE was non-detect in unspiked sample.

commonly used air stripping technology for removing VOCs (U.S. EPA, 1991). In a typical packed tower, water and air pass in a countercurrent mode over a plastic media designed to provide minimal pressure drop and to maximize the gas-liquid interfacial area.

Designing a packed tower involves the determination of the proper tower height, tower diameter, and gas-to-liquid (G/L) ratio. The tower height is a strong function of the desired removal percentage of a VOC. The tower diameter is primarily a function of the liquid flow rate, which is dictated by the flow required to wet a maximum amount of packing surface without flooding the column. The G/L ratio is dependent on the volatility of the VOC being removed. A highly volatile VOC may require a G/L of only 10–20, whereas a relatively less volatile VOC (e.g., MTBE) may require a much higher G/L ratio.

The packed tower used in the pilot study was 0.3 meters in diameter and contained 3 meters of 2.54-centimeter Jaeger polypropylene Tri-Pack packing (Sutherland et al., 2003a). The tower was operated in countercurrent mode with a liquid flow rate of 0.00025 m³/s (5.1 gpm/ft²). G/L ratios ranging from 75:1 to 150:1 were examined.

The results of the study showed that for the five groundwaters, higher G/L ratios (150:1 versus 75:1) provided smaller columns and lower treatment costs. Overall mass transfer coefficients (K_La) (the primary design

parameter) were estimated from pilot tests and were used for column design and subsequent cost estimation.

For each groundwater, unit costs (i.e., capital plus operation) were estimated for MTBE removals of 80 and 99.5 percent from waters containing 100 and 1,000 µg/L, respectively. For the five groundwaters, unit treatment costs ranged from \$1.4–2.2 per 1,000 L at a low flowrate (38 liters/min) to \$0.1–0.3 per 1,000 L at a high flow rate (3,800 L/min). Thus, air stripping provides a significant economy of scale with respect to flowrate.

For the treatment of alternative oxygenates, the efficiency of mass transfer as measured by K_La was ranked from highest to lowest as:

DIPE > ETBE > TAME > MTBE > TBA > EtOH.

Thus, each of the alternative ethers was more easily treated by air stripping than MTBE, while the alcohols (TBA and ethanol) were more difficult to treat. A key consideration for the treatment of MTBE or the alternative oxygenates when using air stripping is the potential need for offgas treatment to prevent the release of the VOCs into the atmosphere.

Activated Carbon Sorption

GAC adsorption is a commonly used technology for removal of trace organic compounds from groundwater and drinking water (Speth and Miltner, 1990). Sorption on GAC is based on reversible physical sorption

principles. The amount of an organic chemical that will sorb to a given mass of GAC, or its capacity (mg VOC/g GAC), is a strong function of the specific surface area of the carbon (m²/g), the surface characteristics of the carbon, and the nature of the organic chemical that is being removed. In general, for molecules of approximately the same molecular weight, greater water solubility of an organic chemical corresponds to lower capacity on a given carbon.

In the work by Sutherland et al. (2003a), carbon adsorption was studied for two bituminous-coal-based carbons—Calgon F400 (a commonly used GAC for drinking water treatment) and Calgon F600 (a more specialized carbon for micropollutant removal). Carbon adsorption was studied in rapid small-scale column tests (RSSCT) described in detail elsewhere (Sutherland et al., 2003a). Breakthrough curves were developed for MTBE from each groundwater on both F400 and F600.

The results showed that F600 had significantly higher capacities than F400 for MTBE. In general, the carbon capacity correlated with the influent concentration of MTBE, as would be expected. The presence of BTEX appeared to diminish the capacity of the carbon for MTBE. This is consistent with the greater selectivity of the carbon for BTEX compounds than MTBE itself. Estimated carbon utilization rates for MTBE in the five groundwaters ranged from 110–440 mg/L on F400 to 50–260 mg/L on

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■ Treatment Technologies

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F600. The carbon utilization rate, however, was seen to be relatively independent of influent MTBE concentration.

While F600 is a more expensive GAC than F400, the higher capacity of F600 provided for lower unit treatment costs for F600 than for F400. Estimated treatment costs for carbon adsorption were significantly higher than air stripping at high flow rates (3800 L/min), but were more competitive at low flow rates (38 L/min).

Breakthrough curves on both F400 and F600 GACs for alternative oxygenate mixtures showed the relative selectivity was ranked (from strongest to weakest) as:

DIPE > TAME > ETBE > MTBE > TBA > EtOH

Note that this is in reverse order of water solubility as would be expected (Sutherland et al., 2003b). Additional work by Adams et al. (2003b) showed that adsorption isotherms on both F400 and F600 were ranked in this same order. The isotherms also showed that DIPE and benzene had similarly high capacities on both carbons, while all other oxygenates had lower capacities.

UV/H₂O₂ and O₃/H₂O₂ Advanced Oxidation

Advanced oxidation processes (AOP) are treatment processes that involve generation of the hydroxyl radical ($\text{OH}\cdot$) as a primary oxidant. There is a wide variety of AOPs that are used commercially and/or on an experimental lab-scale basis (Calgon Carbon Oxidation Technologies, 1996). Two of the most common AOPs are the ultraviolet/peroxide (UV/H₂O₂) and ozone/peroxide (O₃/H₂O₂) processes.

In the UV/H₂O₂ process, H₂O₂ is added to an aqueous stream containing the contaminant of interest and irradiated with UV radiation. The UV radiation cleaves the H₂O₂ into two hydroxyl radicals ready for oxidation. In the O₃/H₂O₂ process, the dissociated form of H₂O₂ reacts with O₃ to form a series of inorganic radicals, including the hydroxyl radical. Other AOPs include UV/O₃, TiO₂/UV, Fe(II)/H₂O₂, sonolytic oxidation, and others.

Each AOP may be more or less effective at oxidizing specific organic chemicals, depending on a variety of process parameters, including background UV absorbance, alkalinity, pH, concentration of hydroxyl radical scavengers, reaction kinetics, and other factors.

UV/H₂O₂ (with a medium-pressure UV lamp) and O₃/H₂O₂ were both included in the pilot-scale MTBE treatment testing by Sutherland et al. (2002 and 2003a). In this work, a 1-kW medium-pressure lamp was used for the UV/H₂O₂ process in a continuous flow system (Aquionics). For the O₃/H₂O₂ process, ozone was generated from 95 percent oxygen to concentrations of approxi-

pH in particular can have a strong effect on process efficiency because it may control speciation of the target organic compounds, hydroxyl radical scavengers, and hydrogen peroxide into more or less reactive species.

Results by Sutherland et al. (2003a) showed that the UV/H₂O₂ process was efficient at removing MTBE from most, but not all, of the groundwaters. Treatment costs varied considerably, from \$0.2–2.8 per 1,000 L treated for four groundwaters to considerably higher costs for Site C water that had a very high chemical oxygen demand (COD), total dissolved solids (TDS), and alkalinity. pH was shown to have a significant effect on process efficiency (EE/O) with lower pH (7 versus 9) providing a much more efficient process and lower costs.

Results by Sutherland et al. (2003a) also showed that the O₃/H₂O₂ process was effective at treating MTBE in some, but not all, of the groundwaters. While estimated treatment costs were lower for the O₃/H₂O₂ process compared with the UV/H₂O₂ in most groundwaters, the O₃/H₂O₂ process was not able to remove MTBE in the groundwater with the highest COD.

The EE/O and estimated treatment costs for the advanced oxidative treatment of the alternative oxygenate ethers—DIPE, ETBE, and TAME—were similar to those for MTBE. pH exerted a significant effect on the treatment efficiency of these alternative oxygenates with a higher pH leading to a lower treatment efficiency.

Summary

The results of this study showed that each treatment process examined—air stripping, carbon adsorption, and advanced oxidation—may be effective at treating MTBE under specific conditions. At higher flow rates (3,800 L/min), air stripping provided the lowest cost alternative for MTBE removal. At lower flow rates (38 L/min), the treatment costs of the four alternatives were more comparable and the process selection was more dependent on site specific conditions.

While air stripping is effective and may be the least costly treatment alternative, especially at high flow

***Each treatment process examined—
air stripping, carbon adsorption, and
advanced oxidation—may be
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***Each of the alternative oxygenate
ethers appears more easily treated
with air stripping than MTBE due to
their greater volatility.***

mately 14 percent (w/w) and injected into the flow stream containing H₂O₂ and MTBE (or alternative oxygenates). A full description of the advanced oxidation systems may be found elsewhere (Sutherland et al., 2002 and 2003a).

Design and comparison of AOP systems is often conducted by determining the electrical energy required per order of magnitude of contaminant concentration reduction (or EE/O). Additionally, chemical and capital costs are also required to properly compare system options. In this work, pilot tests were conducted on each groundwater from which EE/O values were determined under a variety of process conditions (Sutherland et al., 2003a). In general, EE/O values for AOPs can be a strong function of process conditions.

rates, some issues with air stripping include the potential need for tall-packed columns, potential offgas treatment requirements, fouling by iron or carbonate precipitates, and biogrowth.

Carbon adsorption appears effective (especially at lower flow rates) and provides for relative ease of use. Additionally, many other compounds may be concurrently treated effectively with GAC. Fouling and the need to periodically renew the columns with fresh or regenerated carbon are issues that must be considered with the GAC sorption option. Additionally, the presence of other preferentially adsorbed compounds (e.g., BTEX) can adversely affect the ability of the capacity of the carbon for MTBE.

Advanced oxidation was seen to be effective at treating MTBE in most of the groundwaters tested, thereby, offering a viable option for treating many groundwaters containing MTBE. Water chemistry, however, plays a critical role in process efficiency and effectiveness with any AOP and must be carefully evaluated when considering and comparing AOPs for groundwater treatment. A key consideration with respect to advanced oxidative treatment of MTBE or the alternative oxygenates is that chemical oxidation results in the formation of oxidative byproducts (e.g., TBA and *tert*-butyl formate) that may themselves require additional treatment.

Each of the alternative oxygenate ethers appears more easily treated with air stripping than MTBE due to their greater volatility. The EtOH and TBA, however, are less efficiently treated with air stripping, as expected. The same trend is observed for GAC adsorption, where the ethers are more readily treated and the alcohols less readily treated as compared to MTBE (based on relative selectivity). With respect to advanced oxidation, the alternative ethers had comparable removal efficiency to MTBE, while TBA was less effectively removed. No TBA generation was observed with the GAC used in this study.

Other treatment options for MTBE and alternative oxygenates in groundwater that are receiving increased attention include membrane separation and biological treat-

ment. Membrane treatment shows significant promise for treating oxygenates (Liang et al., 1999) as well as a host of other synthetic organic chemicals in groundwater and drinking water. While MTBE, alternative ethers, and TBA are often considered biorecalcitrant, studies also point to the potential for biological treatment of these oxygenates under specialized conditions. Significantly more research may be necessary to fully evaluate the efficacy and stability of biological treatment of these compounds. ■

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How to Collect Reliable Soil-Gas Data for Upward Risk Assessments

Part 2: Surface-Flux-Chamber Method

by Blayne Hartman

Since Part 1 of this topic, *Active Soil-Gas Method*, was printed in October 2002, U.S. EPA has initiated a series of informational workshops/conferences that address the soil-gas upward-migration risk pathway. (See <http://www.clu-in.org/conf/tio/vapor/resource.cfm> for more information.) While the active soil-vapor method is discussed in detail during these workshops, there is little discussion on the surface flux-chamber method. Yet, based on some of the default approaches recommended by U.S. EPA, the surface-flux-chamber method may be the best method to use in some situations. Why is the method not discussed in the guidance? Primarily because of a lack of familiarity, experience, and understanding by the environmental community, including regulators, consultants, and contractors. So let's take a look at this field technique and see when and how it can aid in the assessment of this risk pathway.

Let me start by making two important points concerning surface-flux chambers:

- There is currently no published or official U.S. EPA method for surface-flux chambers. There is a published study performed under contract with EPA that gives a recommended protocol, but it is not regulatory guidance.
- There is no one right way to perform a flux-chamber survey. Like any field technique, there are variations of the method—the suitability of each depends on the project goals.

History

Direct measurement of compound fluxes has been commonly performed in the oceanographic, soil science, and natural resource exploration (i.e., petroleum and minerals) communities for many years. The approach has not been as readily applied to environmental risk assessment.

In the mid 1980s, Radian Corporation, under contract to U.S. EPA, performed a series of testing programs on the method that were summarized in a users guide (Kienbusch, 1986). The method described in this document has often been incorrectly labeled as the official U.S. EPA flux-chamber method. While the document gives a thorough treatment of one flux-chamber approach, including a comprehensive treatment of statistical sampling, it is a recommended protocol only, has several limitations for risk-based applications as described further in this article, and is a difficult read for the inexperienced user.

Subsequent documents by Radian for EPA on air emissions at Superfund sites contain more general discussions on flux-chamber methods and applications (Eklund & Schmidt, 1990).

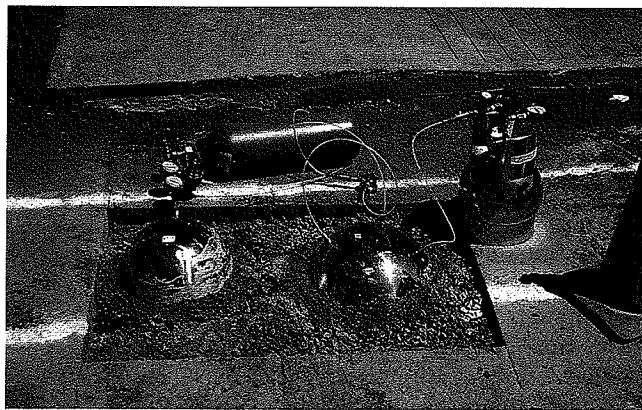
Why Use Flux Chambers?

Currently, risk due to the upward flux of vapor-phase contaminants into an overlying structure is assessed either from direct measurements of indoor air or by the collection of groundwater and/or soil-gas data and the application of a predictive transport model or attenuation factor. Both approaches have limitations.

The determination of upward contaminant flux from the measurement of indoor air is subject to such complications as contributions from the natural background of contaminants in ambient air (especially in urban locations), contributions from sources from within the structure, and temporal and spatial variations. Further, the process is often a logistical headache, especially when the measurements are performed in private residences.

For these and other reasons, U.S. EPA currently recommends collecting subsurface groundwater or soil-gas data prior to the measurement of indoor air concentrations (OSWER Draft Guidance for Evaluating the Vapor Intrusion to Indoor Air Pathway from Groundwater and Soils, November 29, 2002, www.epa.gov/correctiveaction/eis/vapor.htm).

The determination of upward contaminant flux using groundwater or soil-gas data requires the application of a predictive model or attenuation factor to compute the contaminant concentration in an overlying room. Attenuation factors, commonly referred to as alpha factors (α), are defined as the concentration of indoor air to either measured soil-gas concentration (soil-gas alpha) or indoor air to a calculated soil-gas



Surface-flux chambers installed on site.

value from groundwater concentrations using the compound-specific Henry's constant (groundwater alpha).

At present, attenuation factors predicted by the models have yet to be thoroughly validated with field data. Until such time that a sufficient data base is accumulated to test the model-derived values, U.S. EPA, in its vapor intrusion guidance, is recommending the use of default attenuation factors that are conservative and may be overprotective by up to

several orders of magnitude. The ramification is an increased likelihood of falsely concluding that there may be a risk when the assessment is based on subsurface data, especially if site-specific data are not available.

The flux-chamber approach provides a direct measurement of the subsurface contaminant flux and therefore alleviates the uncertainty introduced from the existing predictive flux models or the use of an overly conservative alpha factor. Assuming proper placement, as described below, fluxes measured by this approach should, in theory, be reflective of all of the subsurface fate and transport processes that are operative and difficult to model (e.g., phase partitioning, bioattenuation, preferential pathways, and advective flow).

If flux chambers can solve some of the problems of the other approaches, then why not use them? Because, as with any method, flux chambers are not applicable to all situations and they have their share of limitations that must be understood before attempting to employ them on a site.

Flux-Chamber Application

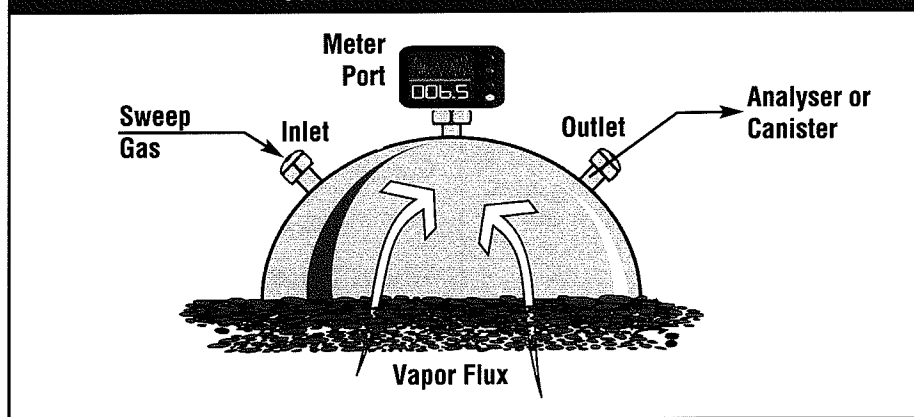
Flux chambers are not applicable to every type of structure or site. For example, the use of chambers in basements or any other subterranean enclosure is not practical because the four walls of the basement could also be a source of vapor flux. Also, flux chamber results from undeveloped lots may or may not be representative of fluxes into a future structure. On one hand, the measured flux could be overestimated because there is no building foundation impeding the flux; on the other hand, the measured flux could be underestimated for such reasons as the lack of pressure-induced advective flow caused by the heating or ventilation system in the overlying structure.

Flux-Chamber Limitations

While factors influencing the results from this method include adequate coverage, measurement time, and temporal variations (these factors also influence indoor air and soil-gas results), the two greatest concerns I have heard voiced from skeptics on this method are:

Figure 1

Schematic of Surface-Flux Chamber



- Doubt as to whether chambers measure the actual flux into a structure due to our inability to place chambers in the location of highest vapor intrusion. Experience from radon intrusion studies over the years has shown that in many structures, especially older ones, the most permeable zones into basements and slabs are at the junction between the structure footing and the slab/floor (i.e., near the walls) or from conduits (e.g., utility lines and pipes) protruding through the walls or slab. Because chamber designs preclude measurements in such locations, the concern is that measured fluxes will be lower than actual fluxes in such situations.

- Concerns as to whether the air-flow conditions inside a chamber match the air-flow conditions in a room. If the air flow in the chamber is more restricted, fluxes could be reduced. If the air-flow conditions in the chamber are higher than in the room, measured fluxes could be overestimated if upward advection is created or underestimated if chamber air is pushed downward into the subsurface.

Employing Flux Chambers

Structures with basements, older construction, and structures containing many conduits through the slab, walls, or floor are not likely to be good candidates for flux chambers. Structures with newer slab-on-grade construction are most applicable for flux chambers. Chambers are applicable to undeveloped lots as long as effects caused by a future building are considered when interpreting the results. Enough chamber measure-

ments should be made to ensure that spatial variations around the building footprint due to potential preferential pathways (e.g., near the footing and slab junction) are adequately covered. Finally, chamber measurements should be made for a period of time sufficient to ensure that any temporal variations in flux are averaged.

Flux-Chamber Methods

There are basically two different types of flux-chamber methods: (a) the Static-(Closed) Chamber Method and (b) the Dynamic-Chamber Method. Both methods offer advantages and disadvantages as described below.

■ Static Chamber

In this method, there is no introduction of gas into the chamber during the incubation period. Contaminants flux into the trapped and stagnant chamber volume, and the contaminant concentration builds up over time. Discrete samples for analysis are withdrawn either at the end of the incubation period or, preferably, at regular intervals during the incubation period. In essence, the chamber acts like a "mini-room," except that there is no air exchange, which provides a time-integrated sample, similar to a Summa canister collected over a specified time period.

The equipment is very simple, consisting essentially of a collection container with sampling ports. (See Figure 1.) Chambers have been made from 55-gallon drums (metal or plastic), Summa canisters, galvanized cans, bowls, and pots. More important than the type of container is the

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chamber material. For most VOCs, the chamber should be constructed of an inert, non-adsorbing material, such as polished stainless steel with a minimum of rough adsorbing sites. (Teflon is not a good choice due to adsorption on its surface.)

Advantages

This method offers many operational advantages over the dynamic method, including the following:

- The equipment and procedures are simpler and less expensive, enabling the deployment of multiple chambers over the same time period, which gives better coverage of the site/structure.
- The method gives a time-integrated sample for long periods, reflecting any flux variations due to temporal effects.
- The simpler system and procedures minimize potential false positives from equipment blanks (e.g., blanks from inlet gas, chamber hardware, or sample containers).
- The absence of flowing inlet and outlet gases minimizes potential disturbances of the natural flux conditions (i.e., creation of advective flow or pressure gradients in the chamber).
- The method is more sensitive (i.e., can detect lower fluxes) as there is no inlet gas diluting/sweeping the contaminant concentration inside the chamber, and contaminant concentrations build up over time. For example, for a 1 in 100,000 risk the "chamber fail concentration" for benzene would be approximately $25 \mu\text{g}/\text{m}^3\text{-hr}$ or $200 \mu\text{g}/\text{m}^3$ over eight hours. This offers the following additional benefits: (a) Required analytical detection limits increase, enabling less expensive measurements and the potential for on-site, real-time measurements. (b) Higher detection limits reduce the potential for false positives.
- Measured values are easier to

interpret for the inexperienced user. Measured chamber concentrations can be compared directly to tabulated acceptable indoor air values or converted easily to a flux as follows:

$$C_{\text{room}} = C_{\text{chamber}} * H_{\text{chamber}} / H_{\text{room}}$$

$$\text{Flux} = C_{\text{chamber}} * V_{\text{chamber}} / A_{\text{chamber}} * T$$

Where: C refers to concentration

H refers to height

V refers to volume

A refers to area

T refers to incubation time

For example, a measured concentration of $10 \mu\text{g}/\text{m}^3$ after an 8-hour period in a 10-inch high chamber would be equivalent to a concentration of $1 \mu\text{g}/\text{m}^3$ in an 8-foot-high room. This value can be compared directly to tabulated acceptable room concentrations for the applicable risk level and allowed room air-exchange rate. Or the value can be easily converted to a flux for input into an exposure model.

Disadvantages

There is one major disadvantage to the static method: If chamber concentrations build up to a significant fraction of the subsurface concentration, the flux will be impeded. By Fick's law, the flux is directly related to concentration gradient; hence, for example, a 20 percent reduction in concentration gradient will lead to a 20 percent reduction in flux.

For sites where emissions are known to be high (e.g., near landfills, compost piles), the flux reduction caused by concentration build up could be significant. But for most upward risk applications, concentration build up will most likely not be significant. For example, existing case studies indicate that the attenuation factors are less than 0.01 for chlorinated solvent sites and less than 0.001 for hydrocarbon sites. The corresponding concentration build up in a static chamber would be 20 percent and 2 percent of the subsurface soil-gas concentration, respectively, for these two attenuation factors.

Any reduction in the measured flux can be identified and corrected for by measuring the chamber concentration periodically during the incubation period. If required detection levels can be achieved, I recom-

mend on-site analysis to enable real-time feedback. Alternatively, multiple samples can be collected from the chamber over the incubation time for off-site analysis. If the measured concentration in the chamber is within 25 percent of the subsurface soil-gas concentration, then it is possible the measured flux was underestimated.

■ Dynamic Chamber

This is the method described in the Radian's Users Guide. In this method, an inlet gas (sweep gas) is continuously introduced into the chamber during the incubation period and an equivalent amount of the chamber gas is allowed to escape. The system is assumed to reach a steady-state concentration after four or five chamber-residence times, where one residence time equals the chamber volume divided by the sweep-gas flow rate.

At steady state, the contaminant concentration in the outlet gas is equivalent to the concentration in the chamber. The concentration in the outlet gas is monitored with a meter, or a sample of the outlet gas is collected for analysis, depending on the required detection level for the contaminants of concern. For risk-based applications requiring low detection levels, the typical approach is to collect a batch sample of the outlet gas for off-site analysis after steady-state conditions have been reached (approximately 30 minutes for the nominal conditions given in the Radian report).

Advantages

The major advantage this method offers is that, except in the most extreme cases, there is little chance for the chamber concentration to build up to a significant fraction of the subsurface concentration due to the inflow and outflow of the sweep gas. Hence, there is very little chance that the measured flux will be impeded by concentration build up in the chamber.

Disadvantages

This method has a number of operational and technical disadvantages, including the following:

- This more complex procedure requires more complicated equipment. In addition to the chamber,

required equipment includes gas tanks, flow regulators, tubing connections, pressure gauges, and larger sample containers, typically canisters with flow chokes. The potential for false positives from equipment blanks is higher than the static method, especially if the equipment is reused on the same site on the same day.

- The more complicated and expensive equipment limits the deployment of multiple chambers covering long time periods at the same time.
- The high dilution of the chamber volume due to sweep gas results in a loss of sensitivity by a factor of 60 to 500 versus static chambers, requiring lower detection limits for the collected sample. For a 1 in 100,000 risk, the allowable benzene flux is less than $0.05 \mu\text{g}/\text{min}\cdot\text{m}^2$, corresponding to a measured concentration of less than 0.5 ppbv. Hence, expensive off-site indoor air (e.g., TO-14) methods are typically required. Finally, all equipment must be ultraclean and field procedures must be conducted with great care to ensure method blanks below these very low levels.
- Direct comparison of the measured concentration in the collected sample to tabulated acceptable room concentrations is not possible, and the conversion is difficult for all but the sophisticated user.
- The inflowing and outflowing sweep gas creates a potential disturbance of the natural flux (e.g., creation of advective flow in the chamber). In the typical application of this method, there is no measure of the air flow out of the exit ports. Without such a measurement, there is no knowledge or control on where the sweep air is going—out the exit ports or out the bottom. Since the air will take the path of least resistance, it is only reasonable to expect that some portion of the air will escape out the bottom, the portion depending on the soil permeability. If this happens, it is a major impediment to the natural flux. Pressure measurements, which are often performed to address this issue, do not give an indication of

the direction of flow, and hence do not solve the uncertainty. In my opinion, this is a major disadvantage and raises doubt over any flux measurements obtained by this method if the output flow is not measured.

- Another major disadvantage is the inability of this method, as generally practiced, to measure any temporal variations over the course of the day due to the assumption of a constant flux (i.e., steady-state conditions). Case studies in the literature clearly document that emissions from soil vary, and even the Radian report acknowledges this as a limitation of the method. Because the residence time of the air in the chamber is so short, a discrete sample collected at the end of an incubation period only reflects the last 30 minutes of time, despite the length of the incubation period. This limitation can be eliminated if a split of the outlet gas is collected continuously over a longer incubation period using a canister equipped with a flow choke.

■ Methods Summary

As discussed, reliable flux measurements can be made with both chamber techniques. For vapor intrusion applications, where low fluxes are likely to be detected, the static-chamber method offers more advantages and fewer disadvantages over the dynamic-chamber method.

This conclusion was also stated in a subsequent document by Radian to EPA Superfund group (Eklund and Schmidt, 1990). If high fluxes are expected (e.g., chlorinated solvent concentrations near the surface greater than 1,000 times allowable ambient air values), collect multiple samples from static chambers over the deployment period to detect any flux reduction due to potential concentration build up.

If the dynamic method is used, the output-gas flow (not pressure) must be measured to ensure that the sweep air is not escaping underneath the chamber and impeding the natural flux.

If previous soil-gas data do not exist, the collection of corresponding soil-gas samples near the flux chambers is advised to substantiate the

presence of target contaminants in the subsurface, especially at chlorinated solvent sites, where vapor clouds are more common.

Key Factors of Concern

The following are some of the key factors to consider when using either flux-chamber method:

- **Coverage** The Radian document gives a statistical approach for determining adequate coverage. However, in practice, as when to choosing the number and location of borings for site assessment, this decision will likely be made based on site-specific issues, such as size of the site/structure, surface features, and budget.

Deploy multiple chambers in any program to provide representation of the area of interest and to determine precision. Chambers should be located in areas where surface features suggest possible conduits to the subsurface (e.g., cracks, drains) and close to the external walls near the junction of the footings and slab. At least one chamber should be deployed in the area of maximum subsurface contaminant concentration, if it has been identified from a previous subsurface investigation.

Keep the following in mind: You wouldn't consider proposing or accepting a site-assessment report with only one analysis from one or two borings, would you? So why would you accept only one or two flux-chamber measurements to characterize this risk pathway?

- **Deployment Period** Chambers should be deployed for a long enough period of time to ensure that temporal variations are measured. I recommend a minimum of eight hours. Longer exposure times, on the order of 24 hours, may be more appropriate since they give a time-integrated result that is more representative of the actual flux into a surface structure. This is especially relevant if climatic variations are extreme from day to night (barometric pressure or temperature).

If the dynamic method is used, samples should be collected

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continuously over the incubation period in a canister equipped with a flow regulator.

- **Chamber Purging and Blank Samples** Purge static chambers after emplacement with clean gas (i.e., air or nitrogen), and immediately collect a sample after the purging is complete. This gives an initial concentration at the start of the flux measurement that should not be included in the final value. For dynamic chambers, collect at least one method blank at the start of the program per chamber and prior to reuse, as recommended in the Radian report.
- **Environmental Conditions** It is well known that emission rates from soil immediately after a rainfall will be lower than from drier soils. A flux-chamber program should wait at least several days after a minor rain event. (The Radian report recommends waiting seven days after a rain event exceeding 0.3 inches of rain.)

Barometric pressure has also been documented to have an effect on emission rates—highest emission rates are found during periods of lower atmospheric pressure. Programs should be avoided during any period of extreme high or low barometric pressure.

Temperature effects have been found to be relatively minor on emission rates, unless the flux is from soil contamination immediately at the surface. The greater effect of ambient temperature will likely be due to changes in the vapor flow below a structure caused by heating/cooling or ventilation systems in the building. Due to this latter issue, flux measurements collected over one or more seasons may be appropriate for locations with large seasonal variations in temperature (high or low).

Special Concerns

The following are some of the special concerns associated with using either flux-chamber method:

- **Use of On-Site Analysis** In my

opinion, on-site analysis is always advised to enable real-time decisions to be made. This is especially helpful for static chambers, where concentration build up could impede the flux. The applicability of on-site analysis will depend on required detection levels and the sensitivity of the on-site instrumentation. For example, the acceptable ambient benzene value for 1 in 100,000 risk is $0.84 \mu\text{g}/\text{m}^3$. For a static-flux chamber concentration with a 20 to 1 height ratio, this is equivalent to approximately $20 \mu\text{g}/\text{m}^3$. If a nominal room air exchange rate of 1 every 2 hours is used, the allowable chamber concentration will be $20 \mu\text{g}/\text{m}^3$ every 2 hours, or $80 \mu\text{g}/\text{m}^3$ over an 8 hour incubation. This detection level can be reached on-site by laboratory-grade photoionization detectors or GC/MS.

- **Petroleum Hydrocarbons and UST Sites** Petroleum hydrocarbons are known to actively biodegrade in the vadose zone if oxygen is present, hence resulting fluxes can be expected to be low unless near-surface soil-gas values exceed 1,000 times allowed ambient values. On-site instruments can typically detect required levels in static chambers.
- **Methane Sites** Fluxes of methane gas into overlying homes near landfills, petroleum-contaminated sites, and dairy farms are of extreme interest to fire departments and building departments around the country. Required methane levels can be easily measured with on-site instruments, hence the static method offers advantages over the dynamic.
- **Solvent Sites** Chlorinated hydrocarbons are not as biodegradable in the vadose zone and, at sites with surface sources of solvents (e.g., dry cleaners, vapor degreasers), vapor clouds may exist. Hence, the potential exists for higher fluxes as substantiated by the higher attenuation factors reported in published studies. If soil-gas data exist and are greater than 1,000 times acceptable ambient air concentrations, ensure that multiple samples are taken if the static method is used.

Published Protocols and References

Unfortunately, there are no regulatory guidance documents governing flux-chamber protocols. The Radian document, referenced previously, is the most comprehensive document, but it only deals with the dynamic method. San Diego County has some limited guidance regarding flux chambers in its Site Assessment Manual, most of which I included in this article (http://www.co.san-diego.ca.us/cnty/cnty_depts/landuse/env_health/lwq/sam/pdf_files/presentations/soil-vapor_guide.pdf). Most other papers on flux-chamber methods are case studies from vendors supplying the service, conference proceedings, or from other disciplines. Three recent papers comparing fluxes measured with chambers to fluxes estimated by models are by Menatti and Fall (2002), Richter and Schmidt (2002) and Frez et. al (1998).

Another Valid Tool

Flux chambers should be considered to be another valid tool for upward vapor risk assessment, in addition to soil-gas data and indoor-air data. Which method to use on a given site depends upon the site-specific goals and the logistical limitations. In my view, the active soil-gas method described in LUSTline #42 offers less uncertainty and more versatility than the other methods for most situations. However, in situations where active soil-gas data are not definitive or can't be collected, and reliable indoor air samples cannot be collected due to background issues or other logistical reasons, then flux chambers may be the best approach.

Prior to publication, several reviewers of this article raised the issue as to whether burial of adsorbent tubes into the cracks of the slab, utility conduits, or room edges might be another viable alternative. In my opinion, such an approach is not useful for quantitative results because one does not know the volume of air that passes through the adsorbent while it is emplaced. Without this knowledge, concentrations cannot be computed. However, one could use this approach as a screening method to decide where the areas of highest flux into a structure are to assist in locating the chambers. ■

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A Message from Cliff Rothenstein, Director, U.S. EPA Office of Underground Storage Tanks

Taking On Today's Challenges

Next year we will celebrate the 20th anniversary of the underground storage tank program. As we approach this major milestone we should pause to reflect on the great job that we have done. Almost two decades ago there were over 2 million buried tanks, many of which were bare steel tanks that were corroding and leaking fuel into the ground. Almost 20 years later, a million and a half of these unsafe tanks have been closed and almost 285,000 petroleum leaks have been cleaned up.

We can all be proud of these accomplishments. The choices we made 20 years ago and throughout our program's history—creating state funds, using performance-based contracting, implementing risk-based corrective action—have served our programs well. Our environment is better because of our work. And we would not have this success without the efforts of the states.

So what's next? On the eve of our anniversary our challenges are not unlike those we faced 20 years ago. In 1984, our first major challenge was how to regulate over 2 million buried tanks. About 15 years ago we promulgated regulations and began to definitively answer this question. We later learned that our newly promulgated regulations would force most substandard tanks to close and stop most new and upgraded tanks from leaking. Today, with better tank equipment in place, our challenge is to make sure tank owners are operating their equipment properly.

About 15 years ago we also began to tackle perhaps the most important challenge—how to pay for cleaning up thousands of known and unknown leaks. Financial assurance was front and center. Private insurance was either not available or prohibitively costly. So to fill the gap and get cleanups under way, the states created one of the most creative tools to pay for cleanups—state funds. By all accounts, they have worked well, funding \$10 billion in cleanups. But

even as state fund programs can take pride in their success many now face a challenge that could paralyze their programs

Tapping State Funds

Today, financial assurance is again front and center but for a different reason. For the past couple of years many cleanup funds have been under attack by state legislatures. Some have declared open season on their funds. I recently took a stroll down the Internet highway and in less than ten minutes found half a dozen articles on this theme in different newspapers—environmental funds being tapped to avert a state budget crisis.

One article reported that lawmakers had asked their state attorney general if it was legal to use funds set aside for LUST cleanups to help balance the state's \$5 billion budget. Another reported a last-minute budget deal to cut the state's trust fund by 20 percent. Another newspaper reported plans to transfer \$10 million from the tank fund to keep the state from going broke. Even worse is the possibility that these taps are not a one-time phenomenon but may occur on a regular basis. It's easy to see this trend, and it's not a pretty reality.

We are in very tough fiscal times. We are all being asked to tighten our belts. Unfortunately, as a result of our programs having been on fiscal diets for so long, we have tightened our belts about as much as we can. Something has to give. According to news reports, it already has. At the funding levels proposed in one state, regulators have been forced to halt work on 1,500 of 5,000 sites targeted for cleanup. Not only are 300 jobs at stake in this state, but their cleanup backlog could take as much as 40 years to complete.

For the sake of our drinking water and our environment, we must resist all attempts to choose either the environment or the economy. Instead, we must find a way to clean

up petroleum contamination, even in tight fiscal times.

Better Program Integration

Our program is at a crossroads, and we have to make some tough choices. Really, we have only two choices. We can maintain the status quo and suffer "death by a thousand cuts," or we can work together and be the proactive innovators we were at our program's beginning. As the old saying goes, "We can hang together or we will hang separately." I suggest that we hang together.

For us, that means better program integration and real coordination between state fund programs, LUST cleanup programs, and compliance programs and the U.S. EPA. Clearly, our needs have changed and our challenges in some ways are more complex than those of 20 years ago. For example, the impact of a state fund's decisions more directly affects, even dictates, how many cleanups its LUST counterpart can complete. And many of the policy choices that LUST and UST programs make, such as cleanup levels, whether to reopen sites, how to address MTBE, even the number of annual compliance inspections, directly affects state funds. Given the fiscally tight world that we live in, it is critical that we all work together more closely.

If We All Hang Together

If we are going to hang together, we need to set some clear goals and we need to make sure our voices are heard. We need to take a close look at how LUST cleanups will be paid for in the future and the role state funds and other forms of financial assurance will play in this effort. We need to better understand emerging trends, evaluate the short- and long-term viability of state funds, and assess our ability to continue to fund cleanups in these days of tighter budgets and potentially recurring taps into the funds.

State funds are perhaps the greatest innovation in our program's history. They not only have enabled tank owners to comply with financial responsibility requirements, they have paid for nearly 285,000 cleanups. Given today's needs and fiscal reali-

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ties, perhaps it's time to consider creating the next generation of state funds. The next generation may be a mix of public funds and private insurance; it may link claims to compliance; it may be limited to past releases—the possibilities are endless.

With the bull's eye on so many state funds and with claims exceeding balances in nearly a quarter of all state funds, these funds can no longer afford to be all things to all people. The time may be ripe for a resurgence of new ideas. I know that some states have already created the next generation of state funds. Some states have transitioned to private insurance. Some funds no longer cover claims for new releases. Others have raised deductibles or required compliance as a condition for coverage.

Let me share another idea that you may want to consider. To improve operator compliance, we have been working with Tennessee and Rhode Island on a compliance workbook—Underground Storage Tanks Environmental Results Program Workbook. [Available in Fall 2003.] While it is first and foremost an UST compliance tool, perhaps state fund programs can use this workbook as a tool to require tank owners to annually certify that they have completed this compliance checklist or successfully completed operator training as a condition for access to the fund. By doing so, tank operators will become more aware of leak detection and upgrade requirements and more vigilant about ensuring their systems are operated and maintained properly. Greater vigilance by owners and operators will likely mean fewer leaks, fewer claims, and less stress on the funds.

These are just a few ideas, but if we are going to all hang together, we need to work together to effectively address our next generation of challenges. This is not an easy task. We will have to muster all of our creative juices, as we have done in the past. We have no choice, but I am certain we will survive these difficult times and successfully meet our current and future challenges. ■

Getting It Right to Begin With Delaware's Systemwide Approach to Preventing Releases

by Peter Rollo

When I joined the Delaware Department of Natural Resources and Environmental Control's (DNREC's) Tank Management Branch (TMB) four years ago, after 16 years in the municipal and industrial environmental consulting field, my orders were to figure out a way to ensure that petroleum releases from USTs are minimized. TMB believes very strongly in pollution prevention; to this end, new tank installations are a major focus and are carefully reviewed. I was told to do what I needed to do to get the job done, using the regulations as my guide. I had a lot of latitude, and I looked forward to the challenge.

I am in the unique position of being the only engineer in the TMB. I review new tank installation submittals, Stage I and Stage II permit applications, retrofit/upgrade requests, and any additional projects requiring engineering involvement. I originally thought that all UST programs have engineers doing similar work, but I found that this is not the case. After four years of observing how things are done in tankland, trying new approaches, checking, and cross-checking, I believe I have achieved my goal, which is ensuring that any new installation is exactly the way it is supposed to be—100 percent in compliance. So I'd like to take this opportunity to share some of my experiences and point out the benefits that come from having the ability to conduct multidisciplinary engineering reviews.

New Tank System Installations

In Delaware, a typical new tank installation facility plan package consists of the information outlined in the "Installation Requirements for New Petroleum UST Systems" below. I handle the plan submittals as if I am the consultant for the facility owner/operator. My goal is to approve the best plan for the least cost. To accomplish this, I need to keep up with technological advancements. Regular communications with manufacturer representatives goes a long way toward satisfying this requirement. I also ask the contractors to let me know when they come across any innovative new technologies. When an installation is complete, our records must reflect exactly what is in the ground. The following are the key steps we take to get to an installation right from the start:

■ **Review the submitted packages for completeness.** An important first step in the installation review process is to check where the tanks are located in relation to wells and sensitive aquifers. Our regulations have a

proviso that any UST system located within a certain distance from wells, aquifers, and any other sensitive areas requiring extra protection must be entirely double walled (i.e., tanks, product lines, vapor lines, and vent lines) and continuously monitored.

■ **Check in with GIS.** Our goal is to have all UST facilities in the state's GIS database. Any new facilities are entered into the database through field surveys. Facility locations are overlaid onto the well and aquifer maps. The distances to sensitive areas are calculated, and the owner/operator is notified of the additional secondary containment and monitoring requirements, should they be necessary.

Note: I have been monitoring two interesting statistics over the last several years. The first is that although our double-walled requirement has been invoked only a few times, 99 percent of new installations are voluntarily installing double-walled tanks and product lines. The second is that a similar percentage of new installations are voluntarily choosing redundant leak detection methods on both

the tanks and product lines. For example, virtually all facilities now have automatic tank gauges. For tanks, we most commonly see inventory control (a requirement in Delaware), interstitial monitoring, and/or monthly tank-tightness testing. The favorite combination for the lines is mechanical automatic line-leak detectors and continuous interstitial sump monitoring.

■ **Cross-check catalog cut sheets and industry standards.** One of the most important submittal items that we require is the catalog information for all components. Our review of these sheets serves a similar function to that of a consultant's shop-drawing review. On several occasions the cut sheets did not match the manufacturer and model number on our UST Registration and Notification Form. This cross-check has helped us catch this problem and has virtually eliminated the installation of unapproved equipment.

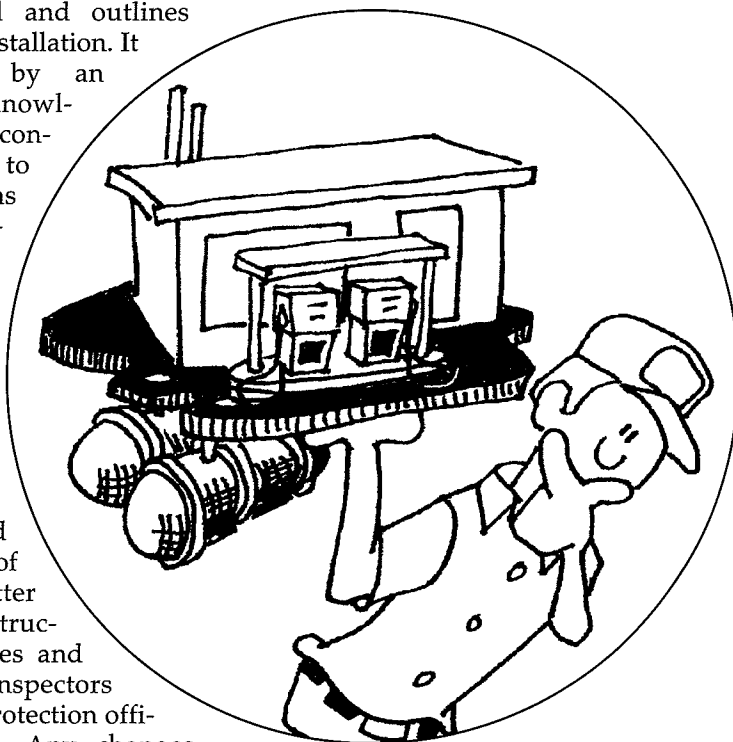
An up-to-date reference library is also important. We maintain our own manufacturers' catalog library. Copies of supplemental documents referenced in the UST regulations pertaining to installations are also very important components of our library. I regularly refer to Petroleum Equipment Institute (PEI) and American Petroleum Institute (API) recommended practices and the National Association of Corrosion Engineers (NACE) standards. With all of this information at my disposal, I set out to review all installation submittals for compliance with all appropriate regulatory documents. At this point, I list all deficiencies and explain them in detail. The deficiencies can be resolved with the owner/operator through the issuance of a deficiency letter, a meeting, a phone conversation, or a combination of these. How it is handled depends on my relationship with the contractor and the type of installation.

■ **Draft the approval letter.** When all deficiencies have been corrected and the submission is deemed complete, I finish the compliance review. I verify that the design meets or exceeds the minimum floatout/anchorage factor of safety, confirm that the design utilizes sound engineering practices, and draft the approval letter. The approval letter is

extremely detailed and outlines every facet of the installation. It is accompanied by an approval letter acknowledgement that the contractor must sign to certify that he has read and understands the approval letter. Someone equipped with just this letter should be able to do the field inspections and know exactly what methods and equipment the contractor is supposed to be using. A copy of this approval letter must be at the construction site at all times and presented to TMB inspectors or environmental protection officers upon request. Any changes made by the contractor during the installation must be submitted in writing and formally approved before the contractor can implement them.

Note: Delaware certifies business entities contracting for or engaged in UST work, which includes installation, retrofit, removal/abandonment, and relining. Individuals supervising installation, retrofit, removal/abandonment, and relining must also be certified. Certification is achieved upon passing a written examination. Certifications are valid for two years and renewed by again passing a written exam.

■ **Track progress.** Through a series of three installation inspections, progress is tracked to ensure the installation proceeds as detailed in the approval letter. Our environmental scientists conduct installation inspections. Inspections take place when tanks are ready to be lowered into the excavation, when the tanks have been backfilled to the top and the piping run installed and ready for pressure testing with air, and when the installation is completed and a final full system precision test has been carried out. The precision test must be done after the concrete cover pad is poured and after all paving is in place. The new tank installation will not be commissioned until this



final testing and inspection has been completed successfully.

Storm Water Catch Basins

An interesting aspect of larger tank installations (e.g., Wal-Mart) is the location and layout of storm water catch basins and retention ponds in relation to fueling areas. When the storm water design drawing is overlaid onto the fueling facility layout, some problems become obvious. The entities designing these facilities are often headquartered in other parts of the United States and fail to do their homework in researching state-specific requirements. Two scenarios are repeatedly found:

■ **Catch basins that are located in fueling areas that discharge to the environment.** Any releases that might occur at UST facilities flow into these catch basins and discharge to retention ponds, which in turn discharge to the environment. When DNREC's Water Resources personnel review UST facility storm water plans, they do not have the plan for the fueling facility; they are concerned about storm water runoff, rather than the potential contamination from the facility itself. Before the TBM will grant approval, the contamination concerns must be

■ continued on page 22

■ Delaware *from page 21*

eliminated. This is generally accomplished by the removal of incorrectly placed catch basins from the storm water design and grading the fueling area so it will tend to hold releases rather than shed them.

■ Catch basins that are connected to the sanitary sewer system. Most municipalities have codes that make such discharges illegal. In these cases, I will approve the sanitary sewer hookup as submitted in the design, as long as the local sewerage authority approves it in writing. However, this has not happened to date. What happens is the sewage authority doesn't approve the hookup, my review stops, and the facility designers are referred to the municipality/sewer authority to correct the problem. When an agreement is reached, the installation drawings are corrected, and the sewerage authority approves the changes in writing. Upon receipt of this information, my review proceeds.

Directly discharging petroleum fuels into the environment or discharging to ill-equipped treatment facilities that will in turn discharge improperly treated water to the environment will cause environmental contamination at some point in time. Yet in many areas of the United States, facilities with large amounts of runoff are being installed without proper review, and no one pays attention to the problem until a contamination episode occurs.

Stage I and Stage II Applications

As with most states requiring vapor recovery, Delaware has adopted the California Air Resources Board (CARB) vapor recovery model. The unique aspect of Delaware's program is that USTs and vapor recovery are integrated within the UST branch. It is not possible to look at an UST facility in its entirety without including vapor recovery.

CARB has arranged its approval system around Executive Orders and Approval Letters. Executive Orders approve the balance or vacuum-assist systems and Approval Letters generally certify components that can

DELAWARE'S INSTALLATION REQUIREMENTS FOR NEW PETROLEUM UST SYSTEMS

A. Site Survey

- Prior to the installation of any underground storage tank system, a site survey must be initiated by the facility owner/operator. The pre-installation site survey must be conducted to determine the locations of nearby buildings, underground utilities, and sewer lines.
- The location of private/public drinking water wells, rivers, streams, lakes, canals, and other environmentally sensitive locations must be recorded and taken into account in the design of the UST system facility.

B. Facility Plan

- Owners/operators must submit a plan of the tank facility to the Department or to a designated state or local government agency for approval 30 days before installation. New tank installation approvals are valid for one year from the date of the approval. If work is to begin after that time, the application must be resubmitted. The scale of the plan must be 1 inch:10 feet or less.
- The site plan must include the installation location, streets, roads, other properties bordering the construction site, and the results from sections A and B.
- The plan(s) must include the following information:
 - Size and location of tanks, including tank dimensions, empty tank weight, tank manufacturer, and tank type
 - Piping dimensions and layout
 - Dimensions and locations of vents, monitoring wells, gauges, and monitoring devices
 - Type of product to be stored in each tank
 - Location of dispensers
 - Location of overfill devices, spill prevention system, and monitoring devices, including dimensions of spill containment manholes and dispenser and piping sumps, when applicable
 - Materials of construction for tank(s) and lines, including associated appurtenances, manufacturer, model numbers, and any manufacturer's catalog information requested by the Department
 - Location of and access to such components as check valves, antisiphon valves (for heating-oil tanks), mechanical line-leak detectors, and flexible connectors
 - Location of cathodic-protection components and test stations
 - Location of utilities (aboveground and underground)
 - Location of electrical service components
 - Details of hold-down pads or anchoring, including cover pads, deadmen, and anchoring methods; depth of cover; all dimensions; vulnerability to vehicular traffic; and electrical isolation methods associated with the anchoring system, if applicable
 - Location of nearby private/public drinking water wells and surface water bodies
 - Survey results from section A above

C. Anchoring of Tanks

- Provide support and anchorage for all new installations to avoid flotation. Any of the following anchoring methods can be used to meet this requirement and must be completed in accordance with the Petroleum Equipment Institute Recommended Practice RP100:
 - Reinforced concrete deadmen anchors
 - Bottom hold-down pad consisting of 8 inches of reinforced concrete that extends 18 inches beyond tank sides and 12 inches beyond each end
 - Reinforced concrete slab over tank
- Electrically isolate and cathodically protect all exposed metallic components of hold-down systems; provide an adequate bed of backfill between the tank and concrete.

D. Piping

- Design the piping layout to minimize crossed lines and interference with conduit and other tank-system components. If crossing of lines is unavoidable, provide adequate clearance to prevent contact. Slope all product, vent, and vapor piping back to the tank with a minimum slope of 1/8 inch per foot.
- Accurately cut and deburr pipe joints to provide liquid-tight seals.
- When rigid piping is used, flex connector(s) must be installed at the tank end of each product line, vent line, and vapor recovery line and at the base of each dispenser and vent riser on all new installations.
- All underground metal pipe/fittings, flexible connectors, joints, and pipes must be coated or wrapped and must have cathodic protection or be isolated by containment boots when appropriate.

E. Backfill Material

- Backfill material must consist of sand, crushed rock, or pea gravel. The material must be clean, washed, inert, free-flowing, homogeneous, well-granulated, noncorrosive, and free of debris, rock, ice, snow, or organic material. Particle length must be no more than 1/8 to 3/4 inch in size and must comply with the manufacturer's specifications. Mixing of backfill with native soil and/or foreign objects is prohibited.

be used with specific CARB executive orders. The application process begins with the submission of a vapor-recovery notification form that, when filled out properly, provides the information needed to advise the applicant. Submitted applications must state the appropriate CARB Executive Order and Approval Letter numbers for the system being used.

Stage I and II applications contain equipment lists and questions detailing all aspects of the work. Again, the goal is to be able to look at the application and know exactly what the contractor is proposing to do. Our review consists of matching all components with the Executive Order and the associated Approval Letters. Proposed equipment that is not specified by CARB must be researched to verify if it is an equivalent of approved components and CARB certified. The research may include contacting manufacturers, CARB, or the contractor in order to finish the verifications. For new tank installations, when all vapor recovery information is submitted and the applications are complete, this information is compared with the tank installation package to be sure they are consistent with each other. On many occasions, inconsistencies have been found during this review.

We have found two common problems associated with vapor-recovery systems and USTs: (a) the vapor-return line does not drain to the lowest octane tank, (b) the vent and vapor manifolds are arranged so as to create an "open vent" situation, which will negate overfill prevention. I try to make sure the vapor connection is right above the ball float. When all problems are resolved, the permits are processed. At this point, the UST and vapor-recovery systems are correctly integrated and the maximum efficiency of the vapor-recovery system is ensured.

As with the installations, copies of vapor-recovery permits must be maintained at the construction site at all times and be presented to inspectors or environmental protection officers upon request. Upon completion of the installation, all appropriate tests are performed, many of which are witnessed by the TMB.

Coping with Cathodic Protection

We continue to check up on the UST system throughout its life, or certain aspects of its life, such as cathodic protection (CP). While correct installation is important, it is not a guarantee of a trouble-free life for an UST system.

CP is one area where there have been problems too numerous to count. These days, CP is encountered on old tanks and lines needing impressed current systems, sti-P3 tanks with anodes, metallic components of tank hold-down systems, metallic flexible connectors, and any other metallic components in direct contact with the environment.

To simplify matters, I have written guidelines that cover CP of metallic components of hold-down systems for tanks up to 20,000 gallons and CP of steel flexible connectors. These guidelines were reviewed and approved by a NACE engineer, so using the guidelines will eliminate the requirement of having a NACE engineer design the system.

When new CP designs are warranted, they are provided by NACE-certified engineers. Compliance testing is performed by NACE-certified testers. CP systems may be installed by certified contractors, provided the installation is supervised by a NACE-certified engineer or tester.

All CP designs must include soil-resistivity test results, type and size of anodes to be installed, details on how anodes are to be installed, the appropriate number of test stations, the ability to disconnect the anodes at the test station to facilitate 100 mV shift testing, and design installation drawings for the facility. All designs are reviewed prior to system installation. Design reviews have exposed common problems. For example, in virtually every design I have reviewed I have found math errors and/or inconsistencies between the design specifications and the CP system installation drawings. In either case, without the review, a standard CP system would have been installed that would never work correctly or would fail after a short time. We have found that CP systems that were installed with these problems prior to our reviews are now failing

after only a few years, when the calculated life of the system should have been at least 20 years.

Math errors, if caught early, are easy to correct, ensuring an accurate design. In most cases, CP designs are completed by a NACE engineer but installed by someone else. This is where the most costly problems occur. The installing entity will often make arbitrary changes to the design, such as increasing the number of anodes, changing the anode type, or reducing the number of test stations.

Our UST regulations require that CP systems be tested for compliance at least every three years; however, once any underground work is performed at a CP-protected site, that site automatically assumes an annual compliance schedule from that point on. As part of my review, I track which facilities meet this latter criterion, and they are notified by letter of the change in testing frequency. Once everything is reviewed, corrected, and installed, the system undergoes a complete compliance test to verify that the system is working as designed.

NACE-recommended practices are very general and leave much of the interpretation to the engineers. We were receiving CP test results reported differently by each NACE tester. This created confusion and, at times, difficulty in telling from the results if the facility passed the appropriate criteria. To correct this problem, I standardized the method of how testing is to be conducted and how the results are to be submitted. (See "Evaluating CP Data" on page 24.)

It's Worth the Trouble

The integrated approach we use identifies many potential problems that would normally go unnoticed. The bottom line is that the quality of the installation goes up, protection of the environment is maximized, and the incidences of releases should be minimized. Releases will never be totally prevented, but I believe our approach minimizes the occurrence of releases and when they do occur it detects them more quickly. ■

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Evaluating CP Data

There are three test criteria that can be used to determine if a tank system is receiving adequate cathodic protection:

- **V_{on}** – A structure-to-soil potential of –850 mV or more negative with the protective current applied. This method is only available for systems where the applied current cannot be interrupted (i.e., sti-P3 tanks). Depending on the size of the tank, three to five readings along the top center line of the tank are typical.
- **V_{io}** – A structure-to-soil potential of –850 mV or more negative with the protective current interrupted. This is referred to as the instant OFF potential. This criterion is applicable to impressed current systems or any galvanic system where the current can be interrupted (i.e., tank hold-down system). Any readings that do not register an instant OFF of –850 mV or more negative must proceed to the 100 mV shift test.
- **100 mV Polarization** – A polarization voltage shift of at least 100mV, commonly referred to as the 100 mV shift test. This criterion is applicable to impressed current and galvanic systems where the protective current can be interrupted. For example, if the instant OFF (VIO) reading is –720 mV, the structure-to-soil potential must decay to at least –620 mV with the current off (V_{off}) for the structure to be cathodically protected.

In the following evaluations, Table 1 demonstrates test results that were incorrectly interpreted and submitted by a NACE-certified tester; Table 2 shows what Delaware wants to see as a minimum.

Table 1. Sample impressed current report that is not acceptable. (Can you spot the problem?)

ID	Location of S/S Potential	S/S Potential Avg. (Volts)			Protection
		ON	OFF	Nat.	
Super UST	East end of tank	–1.21v	–.982v	<–.800v	Meets –.850v criterion
	Mid point of tank	–1.14v	–.877v	<–.850v	Meets –.850v criterion
	Fill end of tank (in grass)	–.970v	–.818v	<–.570v	Meets –.850v criterion
Plus UST	East end of tank	–1.51v	–1.06v	<–.770v	Meets –.850v criterion
	Mid point of tank	–1.28v	–.865v	<–.670v	Meets –.850v criterion
	Fill end of tank (in grass)	–.881v	–.801v	<–.600v	Meets –.850v criterion
Regular UST	East end of tank	–2.01v	–1.01v	<–.760v	Meets –.850v criterion
	Mid point of tank	–1.24v	–.869v	<–.670v	Meets –.850v criterion
	Fill end of tank (in grass)	–.873v	–.798v	<–.600v	Meets –.850v criterion
Regular Slave UST	East end of tank	–1.79v	–1.32v	<–.870v	Meets –.850v criterion
	Mid point of tank	–1.06v	–.839v	<–.600v	Meets –.850v criterion
	Fill end of tank (in grass)	–1.10v	–.953v	<–.700v	Meets –.850v criterion
Vent Piping	Soils at vent pipes	–.873v	–.798v	<–.600v	Meets –.850v criterion

S/S Potential = Structural to Soil Potential

- The tester should have written ON is V_{on}, OFF is Instant Off, Native is V_{off}. The use of Native potentials to demonstrate the formation of 100 mV shift is generally applicable only when a system is initially energized or re-energized after complete depolarization. This is because it is necessary to leave the reference electrode undisturbed (or returned to the exact location) between the time the native and the final voltage are obtained.
- This NACE tester used V_{on} as the pass/fail criteria. This is not permissible. The V_{on} readings all passed the –.850 V criterion but note that five of the instant off readings did not pass the –.850 V pass/fail criteria. They were readings less negative than –.850V. Therefore, this tester incorrectly reported the criterion used to evaluate the CP system. The 100 mV shift criterion should be used for instant OFF readings falling below –.850 V. In this case V_{off} was the same as Native. Rather than spend time waiting for V_{off} to level off, the tester ended the test as soon as compliance with the 100 mV shift criterion was demonstrated. That is what the less-than sign signifies. In the event compliance with the –.850 V instant OFF and/or 100 mV shift criterion cannot be demonstrated, corrective action is required to bring the tank or line into compliance.

Table 2. Corrected impressed current report.

ID	Location of S/S Potential	S/S Potential Avg. (Volts)			Protection
		ON	OFF	Nat.	
Super UST	East end of tank	–1.21v	–.982v	<–.800v	Meets –.850v criterion
	Mid point of tank	–1.14v	–.877v	<–.850v	Meets –.850v criterion
	Fill end of tank (in grass)	–.970v	–.818v	<–.570v	Meets 100 mV criterion
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	Mid point of tank	–1.24v	–.869v	<–.670v	Meets –.850v criterion
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Regular Slave UST	East end of tank	–1.79v	–1.32v	<–.870v	Meets –.850v criterion
	Mid point of tank	–1.06v	–.839v	<–.600v	Meets 100 mV criterion
	Fill end of tank (in grass)	–1.10v	–.953v	<–.700v	Meets –.850v criterion
Vent Piping	Soils at vent pipes	–.873v	–.798v	<–.600v	Meets –.850v criterion

S/S Potential = Structural to Soil Potential

Marcel Moreau is a nationally recognized petroleum storage specialist whose column, *Tank-nically Speaking*, is a regular feature of LUSTLine. As always, we welcome your comments and questions. If there are technical issues that you would like to have Marcel discuss, let him know at marcel.moreau@juno.com

Tank -nically Speaking

by Marcel Moreau

Baffled by a Leak? Check the Inventory Records

Inventory control of fuel stored underground, though long recognized as an invaluable business practice and a valuable leak detection staple, has often been as palatable to UST system operators as Brussels sprouts to a five-year-old. The petroleum marketing trade press from the 1960s and '70s, a time when inventory control was touted as the first line of defense against leaks, documents that even in the face of a burgeoning storage system leak problem, inventory control was not a popular activity among service station operators. Given that inventory in those days required manual sticking, visual reading of totalizer meters, and pencil-and-paper arithmetic, it is no wonder that it seemed more a burdensome chore than a safeguard for economic well being against the possibility of a financial, environmental, or public relations disaster.

And, truth be told, while the mechanics of conducting inventory control are fairly straightforward, the interpretation of the resulting data can be complex. Most petroleum marketers had (and still have today) only a primitive understanding of the sources of error in inventory control and why it is that there are always differences between the book and the stick values in their inventory records. (For a discussion of sources of error in inventory control, see "Inventory Control—the Untold Story," LUSTLine #14.)

Today, reliance on inventory control for storage system leak detection, especially the kind performed completely manually, has largely been supplanted by more mechani-



cally or electronically sophisticated methods. While most of these methods offer clear advantages in terms of leak detection accuracy and reliability, they can also foster an overly complacent attitude that nothing can go wrong. Putting all our leak detection eggs in one basket, even a basket as seemingly secure as secondary containment, has its pitfalls. Consider the following examples.

The Case of the Frosty Fill Pipe

A C-store was doing great—selling over a million gallons a year of gasoline—when the owners went bankrupt. They were puzzled as to why they couldn't seem to make any money. Their storage system was completely secondarily contained, their ATG continuously monitored sensors in the tank interstitial spaces and the piping sumps, and they had electronic line leak detectors, to boot. It was not until an assessment con-

ducted as part of a pending sale of the property revealed tens of thousands of gallons of gasoline in the subsurface that it dawned on all concerned that something had gone very wrong.

The operator had been a pack rat with regards to records, keeping daily sales reports from the point of sale system (POS), daily ATG printouts, and delivery receipts carefully stashed in boxes. But he had never bothered to do the math to track his gasoline inventory. When the inventory data were put together, it became glaringly obvious that some 3 to 4 percent of each delivery into the regular unleaded tank over a three-year period was unaccounted for. The total volume lost was estimated to be in excess of 50,000 gallons.

Because the tank was located in a northern climate and the fill pipe lacked a drop tube, a break in the fill pipe seemed like the most likely

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■ Tank-nically Speaking

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cause of the problem. Subsequent visual observation confirmed that the spill containment manhole had completely separated from the fill-pipe riser.

The Case of the Faulty Filter

A C-store/diner facility was less than a year old and business was good... until the water acquired an unpleasant odor and taste. Water quality testing revealed hydrocarbons and MTBE. How could this happen? The facility was completely secondarily contained and equipped with an ATG that continuously monitored sensors in the tank interstitial spaces and the tank-top piping sumps. There had been no alarms.

Inventory records had been kept, but when things were busy they often slipped to the bottom of the "in" box and no one really looked at them. After all, the facility was virtually brand-new and state-of-the-art, so why bother with inventory records except to see how gasoline sales were doing?

When the "in" box was finally cleaned out, a review of the records revealed disturbingly large daily losses in the super unleaded product for the previous month, amounting to some 5,000 gallons. Visual inspection revealed a dispenser sump with product in it and a leaking fuel filter. Further investigation found a leaky penetration fitting in the dispenser sump. Because there was no sensor in the dispenser sump, the leaky penetration fitting allowed the leaked product to escape silently from the secondary containment system without ever triggering alarms.

Murphy Rules

The moral of these stories is that storage systems are not yet exempt from Murphy's law. With that in mind, let us not forget the virtues of redundant leak detection systems in preventing mishaps from turning into disasters. Though inventory control is far from perfect, these stories illustrate how inventory can be very useful in spotting significant problems that much more sophisticated systems may fail to detect. And with today's technology for determining physical inven-

tory, recording sales volume, and doing the actual math, keeping inventory records and figuring out what they are telling you is a much simpler process than it was 20 years ago.

Where to Begin?

So, you've got a pile of inventory records in front of you, now what? Maybe you want to know the magnitude or the duration of a leak, or maybe you are trying to determine if there is evidence of a leak in the records. Where do you begin? Because reading inventory records is not taught in high schools or colleges, I've prepared an 11-step primer on how to read inventory control records. These are tips that I have learned from reviewing multitudes of inventory records over the years. They are presented in order from simple to more sophisticated:

If you need a refresher on inventory terminology and how to do the calculations, refer to U.S. EPA's publication *Doing Inventory Control Right for Underground Storage Tanks*. (#EPA510-B-93-004, available on the Web at: www.epa.gov/loust/pubs/index.htm).

How Much Data?

Before we go to our primer, we need to think about how much inventory data is enough. Though one month is the industry and regulatory standard period for checking inventory variances, a month is rarely sufficient to get a firm handle on what is happening using the simple means described here. I like to see at least a year of records—and more is always better. It is also often useful to compare what is happening with the different petroleum products at the site, so don't forget to check the records for all products, even if you know which product leaked.

An 11-Step Primer on Reading Inventory Records

Step #1: If the math is done by hand, check the arithmetic.

Though inventory recordkeeping is increasingly automated, some folks are still in the pencil-and-paper era. There are many opportunities for computational errors and slips of the

pencil in a 30-day inventory record. A simple procedure to check for these types of errors is to calculate the monthly variance using a process other than summing up the daily variances to see if you get the same result. To do this, follow these steps:

1. Start with the physical inventory (i.e., the gallons in the tank based on a gauge stick or ATG reading) for the beginning of the month.
2. Add up all the delivery volumes for the month and add this sum to the beginning physical inventory.
3. Add up all the sales numbers for each day of the month and subtract this sum from the beginning physical inventory plus deliveries sum that you just calculated. This gives you the "book" inventory for the month.
4. Subtract this book inventory from the physical inventory for the last day of the month to calculate the monthly variance. The monthly variance calculated this way should be exactly the same as the monthly variance calculated by summing the daily variances for the month.

If the numbers are different, then there is a math error either in the calculation that you just did or in the original inventory record. This little check says nothing about whether the variance is acceptable or not, it just determines whether the variance has been calculated correctly. If you're doing this for more than two months' worth of data, it is probably worthwhile to construct a spreadsheet, using standard software, to do the calculations for you. If you don't feel like reinventing the wheel, an inventory calculation spreadsheet can be downloaded for free at www.kwaleak.com/technical/index.htm.

Step #2: If physical inventory is measured with a gauge stick, check the stick and the records to determine if measurements were made properly.

Check the gauge stick to be sure that it doesn't have a piece missing from the bottom and that the numbers are clearly legible. Also check the tank chart and try to determine if it is the correct chart for the tank. If you have no way of telling whether the tank chart is correct, don't worry, the

inventory records will tell you. (See Step #10, below.)

If you are interested in checking the inventory records for regulatory compliance purposes, you need to know whether measurements were made to the nearest 1/8 inch. If inch measurements are recorded (as opposed to just gallons), you can verify that the required accuracy is being used by checking the frequency with which 1/8-inch measurements occur in the inventory record. In any given inch on a gauge stick, there is one whole-inch mark, one 1/2-inch mark, two 1/4-inch marks, and four 1/8-inch marks.

Because four out of the eight possible readings are eighths of an inch, then pretty close to half of all the measurements in an inventory control record should be 1/8-inch measurements (assuming that the liquid-level variation in the tank is random). If only a few measurements in a 30-day record are eighths of an inch, then measurements are not consistently meeting regulatory requirements.

Step #3: Count the positive and negative variances.

One of the most powerful methods for quickly evaluating an inventory record is to count the number of positive and negative daily variances over a month-long (or longer) period. If there are no leaks and there are no other measurement issues (e.g., meters are accurately calibrated, correct tank chart is used, ATG is programmed correctly), then there should be a very nearly equal number of positive and negative daily variances over the period of record. If the number of positives and negatives is not closely balanced, then there is something going on that you need to investigate. Keep in mind that it is not necessarily a leak. There could be a meter-calibration problem or a tank-chart problem or some other problem with the measurements. But the inventory records may not be very useful for release detection unless the cause of the imbalance is identified.

Step #4: Look for "bounce" in the record.

It is not uncommon in inventory records to see a substantially larger than normal variance one day and a

similarly large variance, but with the opposite sign, the following day. This type of event is often referred to as "bounce," which is usually attributable to some slip in the recordkeeping, perhaps a misreading of the gauge stick or an erroneous conversion from stick reading to gallons. Bounce could also be due to sales volume and physical inventory measurements not being taken at the same time, or failure to record a product delivery on the correct day. Because the errors are typically of similar magnitude and opposite sign, they do not have a significant effect on the overall inventory variance calculation, as long as they occur infrequently.

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Step #5: Look for large discrepancies on delivery days.

Delivery-day variances are often larger than non-delivery-day variances. This is because tank-tilt and tank-chart errors will be accentuated by the typically large quantity of fuel that is added to the tank. But unusually large delivery-day variances that do not "bounce" back the next day may be an indication that a tank was overfilled. Alternatively, it might be a sign that the overfill prevention device was triggered before the entire quantity of fuel brought to the site was delivered into the intended tank.

What may have happened is that the driver dropped the excess fuel into an adjacent tank, even if the fuel had a different octane rating. This is often called a "cross drop." Check for this by comparing inventory variances for all the tanks present at the site. You might find that on a given day, there was a 400-gallon shortage in the regular unleaded product, and a 410-gallon overage on the super product. If the normal daily variances

are much smaller than this (say a few tens of gallons), then this is fairly conclusive evidence that a cross drop has occurred.

Depending on whether the cross drop was the result of an overfill or the activation of an overfill device and the driver's response to the situation, a delivery spill may also have occurred. Check the delivery receipt for before and after stick readings that the driver may have recorded for additional clues as to what happened. A post-delivery stick reading of 110 inches in a 92-inch diameter tank is a dead giveaway to an overfill event. If available, ATG delivery reports can also provide information about the after-delivery tank level and the amount of fuel that was actually delivered into each tank.

Step #6: Check meter calibration.

Look for meter-calibration stickers typically affixed to the dispensers by weights and measures people to determine if meter miscalibration may be an issue. Even if meters have been calibrated in the not-too-distant past, meter calibration is always something to consider when inventory variances are out of line.

Step #7: Evaluate the variances with a critical eye.

Are the daily variances in the hundreds of gallons most every day? If so, it may be difficult to see anything but a leak of epic proportions. Still, this type of record can be evidence of carelessness, unless the facility is a truck stop with extraordinarily high sales volume.

Do the daily inventory variances seem too good to be true? If a facility is receiving a delivery a day and the delivery variances are consistently in the single digits, you should begin to wonder. While there are completely automated inventory systems that can deliver this kind of accuracy, they are not in common use. The extreme case of "impossible" variance is if the daily variance is zero. If variances are zero more than about once a year, then it is fairly safe to conclude that the data are being fudged.

The most common "fudging" technique is to calculate the book inventory and then either make the physical inventory equal the book

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■ Tank-nically Speaking

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value or find a value on the tank chart that is close to the book inventory and write it in. If you suspect fudging, look for errors in copying numbers such as transposing digits (the stick inventory is 3,572, but it is carried forward the next day as 5,372) that still somehow result in very small daily variances.

Another check on fudging is to see if the end-of-month stick inventory is carried forward to the beginning of the next month. Often, an actual beginning inventory number is used to start the month, but this number may be substantially different than the "fudged" stick inventory from the end of the previous month. In an accurate inventory record, the end stick inventory of the previous month is equal to the start stick inventory of the following month.

Step #8: If it's a blended system, look for significant gains in one product that may be approximately equal to significant losses in the other product.

This is often an indication that the blend ratio programmed into the cash register or point-of-sale (POS) system is not exactly equal to the blend ratio that is happening at the dispenser. This happens because the POS system tracks sales of mid-grade product separately from the other products. At the end of the day, the mid-grade sales are divided up and added to the regular and super product according to a fixed ratio (typically 60/40 or 70/30). If the dispenser is in fact blending in a ratio of 65/35, then the fraction of the mid-grade sales volume allocated to the regular and super products will be in error, and corresponding overages and shortages will appear in the regular and super inventory records.

One way to check for this type of error is to compare the sales numbers for the regular and super products obtained from the POS data (add the mid-grade sales in the proper ratio to the regular and super sales volume recorded by the POS system) with the sales numbers recorded by the mechanical totalizers at the dispensers for the regular and super product. If these numbers don't

match almost exactly, then some adjustment in the blend ratio used to allocate the mid-grade sales to the regular and super product must likely be made.

Still scratching your head?

Now that spreadsheet programs with graphing capabilities are commonly available, the graphical analysis of inventory records is simple to do and can be very informative. I usually look at two plots. The first is a plot of the daily variances over time, the other is the cumulative variances (sum of the daily variances) over time. These plots can be done over a period of a month, but the cumulative variance, in particular, is most instructive when plotted over much longer periods, such as a year. The following three steps cover some things to look for in this regard.

Step #9: Evaluate long-term trends.

Cumulative variance plotted over periods of six months or a year can reveal longer-term trends that are often masked when shorter time periods are plotted, especially if the daily variances show a lot of scatter. The longer-term picture allows you to see the "forest" as well as the "trees" more easily.

It may be necessary to eliminate some daily variance data points because they are so large they obscure the trends. For example, if there is a 5,000-gallon-plus daily variance that did not bounce, odds are that there is a delivery that was never recorded into the inventory records. This enormous variance will overwhelm smaller trends because the plotting software will automatically plot the data on a scale that accommodates this 5,000-gallon variance. Removal of such large "outliers" is often required to see more clearly what an inventory record is telling you.

Step #10: Look for a saw-tooth pattern.

A not uncommon pattern that appears when cumulative variance is plotted on a shorter time frame (e.g., a month or so) is a saw-tooth pattern. This pattern may show decreasing cumulative variance for several days, followed by a single positive variance approximately equal to the sum of the negative variances of the previ-

ous few days. A check of the data will reveal that the negative variances occur on non-delivery days, while the positive variances occur on delivery days.

This pattern is indicative of a chart error or ATG calibration error. For example, if an ATG has been programmed for a 10,500-gallon tank when it is really monitoring a 10,000-gallon tank, then sales volume (metered at the dispenser) will be overestimated by the tank gauge, and the daily variance on non-delivery days will be negative. On delivery days, the volume of the delivery will also be overestimated, and the daily variance on delivery days will tend to be positive. Of course, this pattern will be inverted (positive variances on non-delivery days and negative variances on delivery days) if the ATG has been programmed for a 9,500 gallon tank when it is really monitoring a 10,000 gallon tank.

Depending on the magnitude of the chart error and the accuracy of the inventory records, this error may be very obvious, or it may be obscured. Although this error sounds like it might totally invalidate an inventory record, this is not the case. If the period of the inventory records is long relative to the period between deliveries, the net effect of the error is negligible, and the long-term trend of the cumulative variance will still be valid.

Step #11: Look for diverging variances in a blended system.

Plotting cumulative variances of both the low- and the high-grade products in a blended system on the same chart will clearly illustrate if there is a blending error. This will show up as diverging variances of approximately equal value, even over long periods of record. To remove the effects of blending error from the record, simply plot the sum of the variances of the low-grade and high-grade products.

Tip: Know What You Won't Know

Though inventory control may reveal leaks that escape other leak-detection methods, it is also true that there are some leaks that are invisible to inventory control. Most obviously, inventory will not tell you anything about

what is happening beyond the meter in the dispenser.

For example, truck stops often have "satellite dispensers," where a second hose connected to the primary dispenser goes underground to the opposite side of the vehicle so both tanks of the truck can be fueled at the same time in a single sales transaction. Any product leaked from the piping that goes over to the satellite dispenser has already been accounted for by the meter in the primary dispenser and will not appear as a loss in the inventory record. Thus inventory control (and, for the same reason, SIR too) cannot be used for leak detection on satellite dispenser piping.

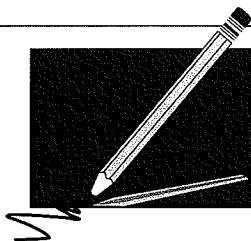
Also, if it is the meter itself that is leaking, the leak may remain undetected if the product is leaking out at a point on the meter after it has passed through the metering mechanism.

Inventory may not always be able to tell you what has happened. As always, the "garbage in/garbage out" rule applies. The value of inventory records in deciphering the history of a storage system is directly related to the accuracy and consistency with which the records were kept.

A Final Word

Although it's been a long time since I've heard anyone proclaim that inventory is the first line of defense against leaks, there is no question that inventory is still an indispensable business practice and a potentially valuable tool for a tank operator in detecting large releases or for a tank regulator in getting to the bottom of a release "after the fact." While inventory records can be laborious to decipher, the "Aha!" moments that sometimes occur when a plot of the data reveals a clear picture of a problem can also be a great feeling. For those of you who love a good detective story, inventory presents a real world opportunity to test your Holmesian skills. ■

P.S. If you have any favorite inventory analysis tips that you use, drop me a line at marcel.moreau@juno.com and we'll share it in a future LUSTline. Or if you have a particularly puzzling inventory record, send it along and I'll take a peek at it.



From Our Readers

Thoughts on the Tortoise and the Hare Revisited

Carol Eighmey, Executive Director of the Missouri Petroleum Storage Tank Insurance Fund, sent Marcel Moreau the following thoughts on his LUSTline #43 cover article, "The Tortoise and the Hare Revisited":

I compliment you on your analysis and thoughtful suggestions. Too often, we fail to step back and look at the "larger picture," and your article does that well.

Without a doubt, the federal UST regulations have served their purposes well. But as you point out, they were written in anticipation of changes, or to trigger changes, that have now largely been accomplished. For states that have "no stricter than" limitations, it is important for EPA to take the lead in addressing such things as the appropriate leak rate for testing line-leak detectors, sensors in secondary-containment sumps, and what the requirements are on tanks that were both lined and had cathodic protection added. Some "updating" of the federal UST regulations is probably needed. And as you note, with improvements in technology, consideration should be given to tightening standards.

On the other hand, as you also note, EPA is hampered by its inability to accurately assess the effectiveness of the current regulations. I began getting nervous when I saw your graphs toward the end of the article. In Missouri, and perhaps in other states, the data on "new

releases" reported annually to EPA includes significant numbers of old tank sites that have recently been assessed for property and similar transactions. At many of these sites, the tanks have been out of service for 10, 20, or 30 years. Obviously, by including these tanks in the count of "new LUST sites," we are skewing the data. Without data on the number of actual releases from operating facilities, no conclusions about the frequency of leaks can be drawn.

There is another question we should ask ourselves: What is a reasonable loss ratio? There will always be some risk of releases—if there were not, there would be no need for an FR requirement. Is a regulatory system successful if it prevents leaks at 95 percent of operating tanks annually? 98 percent? 99 percent? When is the cost of additional prevention higher than the price we are willing to pay for an incremental reduction in loss ratio? I find it curious that few in the regulatory community want to discuss this.

The California study was interesting, but there was a noticeable lack of risk analysis in the regulatory discussions. [See the CA report at: http://www.swrcb.ca.gov/cwphome/ust/docs/fbr/FBR_Final_Report.pdf.] Is one liquid leak in 182 systems an acceptable loss ratio? At how many of the 61 percent of sites with vapor leaks was there an elevated and unacceptable risk to public health or environment from the leak?

In summary, let me suggest that public policy decisions should be based on thorough, reliable data and a thorough discussion of the risk management implications of various alternatives.

Thank you for raising these issues in your article, and for fostering further discussion. ■



Tanks Down East

by W. David McCaskill

David McCaskill is an Environmental Engineer with the Maine Department of Environmental Protection. *Tanks Down East* is a regular feature of LUSTLine. David can be reached at David.Mccaskill@maine.gov. As always, we welcome your comments.



Mending the Armor Maine's Dispenser and Submersible-Pump Sump Study

The rolling landscape of farms, fields, and forests in rural mid-Maine was once the breadbasket of Boston. Some of the farms remain today, but the crosscut saws and horse teams have been replaced with chainsaws and skidders. And the old squeaky-floor general store is quickly being usurped by the modern convenience store, complete with drive-through and pick-up coffee, breakfast, sandwich, and pizza services. One such critter popped up on the landscape in rural Maine smack dab between a couple of homes with private wells. This installation took place a few years prior to Maine's UST siting law, when it was still legal to install gas tanks close to private drinking water wells. (See LUSTline #38, "There Ought to be a Law.") Less than a year later, the customers didn't have a choice between caffeinated or decaffeinated coffee, because the only thing being served was honest-to-goodness high-test!

During Maine DEP's investigation, the tanks and piping were found tight, and no product was found in the dispenser or tank containment sumps. But after the removal of about 9,000 yards of contaminated soil, we estimated that some 6,000 gallons of super had been released into the ground. The interstitial space of the double-walled flexible piping between the dispensers was full of water and gas, and the hottest soil reading was under the far super dispenser. We later found that the containment sump under this dispenser had a breach in the sump pen-

etration where a Stage II vapor-recovery line entered the bottom of the sump.

It seemed that gas had leaked from somewhere in the dispenser into and out of the dispenser containment sump and that some of the gas had become trapped in the double-walled piping between the dispensers. Product never made it to the tank-top piping sump, where it presumably would have been picked up by the leak-detection probe. As it was, the gasoline leaked out quicker than it could be detected. So it took bad coffee to announce that 6,000 gallons of super unleaded was missing.

The breach in our armor was that we did not address dispenser sumps in our rules and that aboveground components of the dispenser could leak and remain uncontained and undetected.

Well, after a \$1 million plus cleanup, we are still asking the owner for answers on how that much product slipped by...and for financial contributions to the cleanup cause.

Breach in the Armor

Since 1991, Maine has stalwartly relied on secondary containment with continuous leak detection as its sword and shield against leaks from

USTs. The breach in our armor was that we did not address dispenser sumps in our rules and that above-ground components of the dispenser could leak and remain uncontained and undetected.

Since the advent of flexible piping some 10 years ago, we have had a de facto dispenser containment sump requirement for all flexible piping, as the manufacturers require that all their fittings be housed in containment sumps. As illustrated in the opening story, using dispenser sumps without probes relies on product filling the dispenser sump up to a point where it can flow through the secondary piping back to the tank and then fill the tank sump to a level that trips the leak-detection probe—a kind of Rube Goldberg operation when you think of it!

Not too long ago, we decided it was time to make dispenser sumps with continuous monitoring a part of our UST armor. To provide solid data to support a rule change, we commissioned a study to answer the following questions:

- What level of contamination are we finding under dispensers and around submersible pumps?
- Which dispenser and submersible-pump components are leaking?

There had been two other such efforts elsewhere in the nation to assess the problem. The first was a survey by the Petroleum Equipment Institute (PEI) of 28 members operating in 45 states. (See LUSTline #41,

"PEI Members Weigh in on UST System Performance.") The second was an EPA-funded study titled *The Frequency and Extent of Dispenser Releases at Underground Storage Tank Facilities in South Carolina*. The PEI survey asked participants what they thought, based on their experience, they would see under dispensers and submersible pumps. The EPA-South Carolina study was based on an analysis of soil samples taken at tank removals.

In our study, Maine DEP hired a consultant to inspect 99 randomly selected active motor-fuel UST facilities throughout the state. The actual inspections were performed from May to November of 2002.

The percentage breakdown of the tank population studied was as follows:

- Retail facilities – 74 percent
- Commercial – 10 percent
- Government – 16 percent

With respect to piping systems, there were 143 pressure dispensers and 110 suction dispensers. Roughly half of these dispensers (124) had containment sumps, compared with 129 that did not. Of the 118 submersible pumps inspected, 99 had containment sumps and 19 did not.

Stains, Weeps, Drips

To quantify the magnitude of releases found during the study, we defined leaks from minor to major as stains, weeps, or drips. A "stain" was defined as a visible discoloration of a fuel-system component that was not wet to the touch and didn't cause product paste to turn color when applied. A "weep" was defined as a wet surface that caused product paste to turn color but did not produce any "drips" of product. Finally, a "drip" was defined as an observed droplet of product that would fall and reform when the pump was turned on.

So What Did We Find?

■ What is the level of contamination beneath dispensers?

Of the 124 dispenser sumps inspected, 72 percent were dry, 19 percent contained water, and 9 percent contained product. Almost all occurrences of liquids in the sumps were minor, with the product or water forming small puddles less than one inch deep. We sampled the soil under 124 dispensers without sumps using the Maine DEP bag

explain why the containment sumps seemed to be so much cleaner than the soil beneath the dispensers without containment.

■ Which dispenser components are leaking?

After inspecting 154 suction pumps, 448 filters, 814 meters, 445 unions, and 328 crash valves, we found very few smoking guns. Weeps were observed in 3 to 8 percent of components, and drips were observed in

fewer than one percent of components. Staining, however, was observed in 6 to 13 percent of all the components, except for suction pumps, where staining was observed 21 percent of the time.

■ What is the level of contamination around submersible pumps?

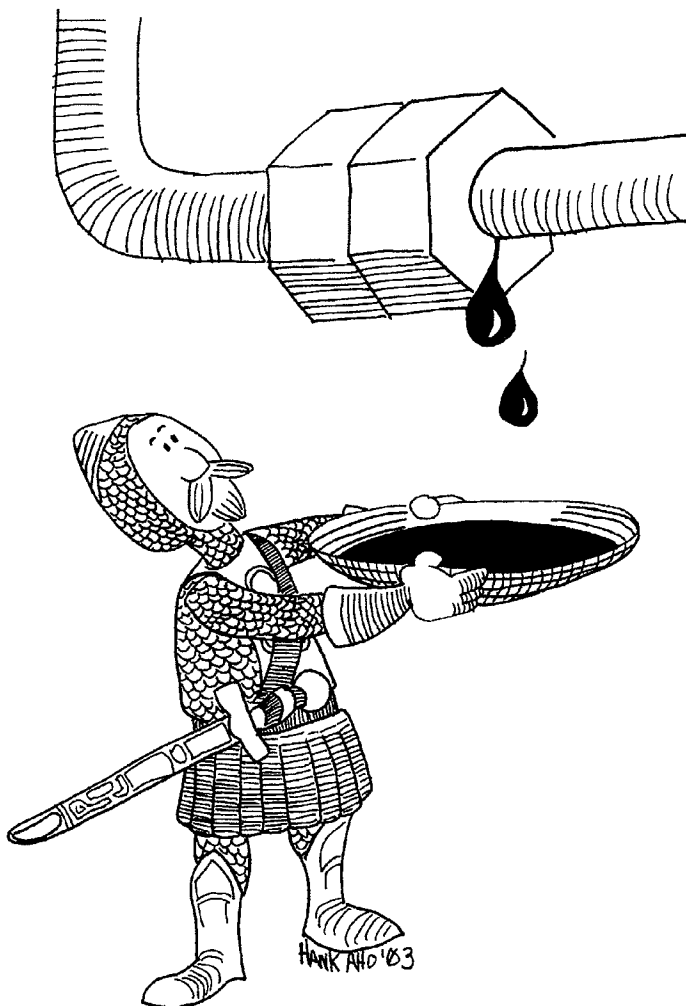
For submersible pumps, 57 percent of the sumps contained water—a few over 20 inches! Only 8 percent of submersible pump sumps contained product, and that was mostly in the form of small puddles in the corners and pockets of the sumps. The soil beneath 63 percent of the submersible pumps without containment sumps had contamination levels above 100 ppm tph; 32 percent had levels over 1,000 ppm.

With regard to the sources of this contamination, an inspection of 51 unions, 107 line-leak detectors, 107 functional elements, 598 pipe joints, and 22 flexible connectors revealed that virtually all

were clean. Again, there is this nagging paradox between the dearth of product in the sumps, the dearth of observed leaks, and the prevalence of contaminated soil beneath the submersible pumps.

Why? Why? Why?

With no real leaking guns we have come up with some theories:



head-space photoionization-detection protocol used during site assessments. (We were unable to collect samples under five of the dispensers due to access problems.)

We found that around half of the samples exceeded our existing 100 ppm total petroleum hydrocarbon (tph) level for reporting evidence of a leak, and over a quarter of the readings were over 1,000 ppm! We were left scratching our heads trying to

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■ Tanks Down East *from page 31*

■ Dirty Dirt?

During a meeting of tank owners concerning proposed changes to our UST rules, a claim was made that our study was flawed in that that it wasn't limited to sites where there had been no previous tanks. The theory put forward was that we could be seeing contaminated soil left over or returned to the excavation from a tank upgrade. This comment was made by a tank owner who had a site that was included in the study. In this case, the soil cleanup level was 500 ppm because the site was in an urban area served by public water. Soil samples taken under the dispensers during our study were found to be as high as 300 ppm.

So, could the contamination at some of these sites come from dirty dirt left over after the old tanks and piping came out? We looked through the data and found that of the 99 sites, 26 had never had tanks before, while the others had had non-conforming tanks removed and new ones installed.

Of the sites that had no containment sumps and that had never had tanks removed, 38 percent had soil contamination above the 100 ppm tph reporting level. Of the sites that had had previous tanks removed and had no containment sumps, 26 percent had soil contamination above 100 ppm. The data do not support the hypothesis that residual contamination is responsible for the high PID readings.

Furthermore, all of the samples taken during this study were shallow grab samples less than 12 inches deep. In almost all cases, the material sampled was sand or gravel backfill, not native soil. The above-mentioned site had fiberglass-reinforced plastic (FRP) piping, which requires specific backfill that can be assumed to be reasonably clean when installed. For this material to be contaminated by remaining or backfilled underlying contaminated soils, the water table would have to come all the way up to the surface to smear the contamination.

■ Messy Maintenance?

It is possible that we are just seeing contamination resulting from spills

during fuel-filter changes and other maintenance activities in the dispenser area. In fact, that did happen on the very first inspection of the study. Our consultant showed up at a convenience store next to a large shopping-mall parking lot and found more than 2,500 ppm tph in the soil beneath the dispensers. When the manager was informed of the finding, he explained that the Stage II vapor recovery testing contractor had just been there that morning and had to replace clogged fuel filters in order to complete the test.

And since we do have contamination under fuel dispensers (we just don't always know why), we've gone ahead and proposed changes to our UST rules to require dispenser sumps and monitoring under all new motor-fuel dispensers.

Changing the filter of an UST fuel system almost always results in spillage. The trick is for the technician to catch as much as possible with spill pans or sorbent material. Changing fuel filters was a common story/reason given for the high levels of dirty dirt found throughout the field inspections. What is interesting about the dispensers with containment sumps is that the majority of the sumps were dry and dusty. Does the presence of containment make filter changers more conscientious about spillage? Do sumps facilitate cleaning up the spillage? Or does the product evaporate away without a trace?

■ That Vapor Thing?

Could the soil contamination result from the migration of product vapors into porous backfill, such as crushed stone? This doesn't sound like a likely story, does it? But a comparison of contaminated soil types found under dispensers without sumps showed that 24 percent of sand, 71 percent of crushed stone, and 81 percent of finer-grain soils had contamination above 100 ppm.

■ Former Leaks?

Another hypothesis is that all the dirty dirt we saw was the result of former leaks that were fixed. Maine has a mandatory annual UST equipment inspection (for leak detection and spill and overfill equipment). So many drips happen but are caught and fixed sometime during the year before they can cause bigger problems.

Onward with Making the Mend

As you can see, I don't have any nice neat answers this time—only theories, at best. In fact, I would be happy for some input on this one. The complete study will soon be available at the Maine DEP Web site at www.state.me.us/dep/rwm/usts/index.htm.

And since we do have contamination under fuel dispensers (we just don't always know why), we've gone ahead and proposed changes to our UST rules to require dispenser sumps and monitoring under all new motor-fuel dispensers. Based on the contaminated soils found in the study, whether resulting from maintenance activities or the lack thereof, this change seems justified—it's the right thing to do!. We may also use these results to incorporate guidelines for inspecting dispensers into our existing annual tank inspection program.

What's next with containment sumps? Retrofitting of dispenser sumps at existing facilities? (A tough sell politically.) Routine testing for all sumps? We'll wait and see what California and the testing manufacturers do on this one. Meanwhile, between tweaking our UST rules and torturing ourselves for not doing more earlier, we continue to soothe our collective being with our mantra: Our best armor is our sensitive-area UST siting law, founded on the observation that the only UST that doesn't have a release is the one that was never built. ■

Field Notes

from Robert N. Renkes, Executive Vice President, Petroleum Equipment Institute

PEI'S 2003 EDITION OF RECOMMENDED PRACTICES FOR INSTALLATION OF ABOVEGROUND STORAGE SYSTEMS FOR MOTOR VEHICLE FUELING TELLS YOU WHAT YOU NEED TO KNOW

Historically, petroleum products at service stations and other motor-vehicle fueling sites have been stored in underground tanks. But to avoid the cost of complying with EPA's underground storage tank requirements and with improvements in petroleum storage tank technologies, aboveground storage tanks (ASTs) at motor-vehicle-fueling sites have become much more common.

The installation of all types of liquid motor-fuel storage systems is highly complex and requires a wide range of construction knowledge and experience. In addition to designing aboveground systems properly, reliance on tank installers who possess both the experience and integrity to insist on following industrywide recommended practices constitutes the greatest protection against tank-system failure and liability exposure.

The Petroleum Equipment Institute (PEI) has revised its *Recommended Practices for Installation of*

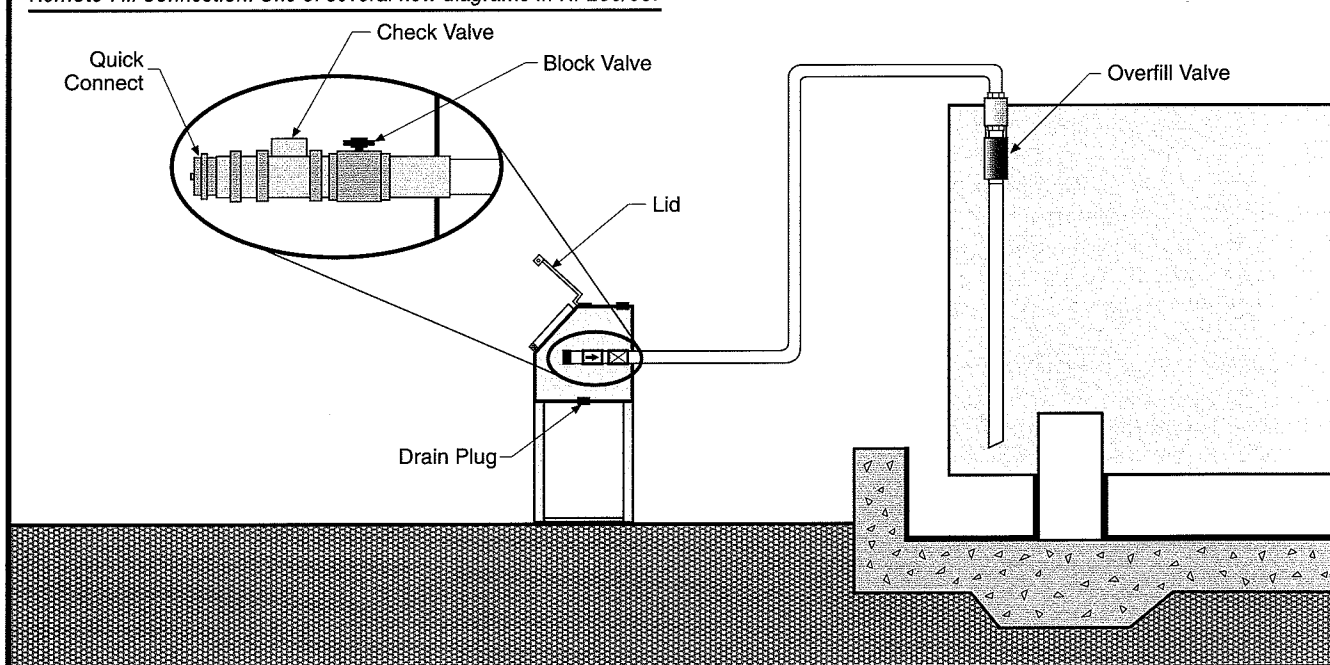
Aboveground Storage Systems for Motor Vehicle Fueling (PEI/RP200) document, a concise reference that describes recommended practices for the installation of aboveground storage systems at service stations, marinas, and other motor vehicle fueling sites. In this document, PEI suggests ways to minimize the possibility of aboveground storage system failure and reduce fire-safety and environmental hazards, while avoiding practices that will needlessly increase installation costs.

The recommendations contained in PEI/RP200 may be applied to horizontal and vertical tanks, single- and multi-walled tanks, as well as insulated and fire-protected (resistant) tanks. Tanks covered in these recommended practices are intended for the storage of liquid motor fuels at or near atmospheric pressure. Product piping associated with these tanks may be aboveground, underground, or a combination of the two.

The 48-page, 2003 edition of PEI/RP200 supersedes and replaces the 1999 edition. The manual contains chapters and drawings on all phases of proper AST installation, including site planning; foundations; support and anchorage; dikes; vaults and special enclosures; tanks; pumps and valves; fills, gauges, and vents; piping and fittings; corrosion protection; electrical installation; testing and inspection; and documentation, maintenance, and training. Three appendices describe size calculations for dikes, venting, and fire code requirements. An appendix of documents used for reference is also included.

The single-copy price for RP200/03 is \$25 for PEI members and government officials; \$75 for everyone else. You can place an order on-line or download an order form at www.pei.org/shopping. You can also request an order form from PEI by calling (918) 494-9696 or faxing (918) 491-9895. ■

Remote-Fill Connection: One of several new diagrams in RP200/03.



California Updates Guidance on ELD and SIR

In May 2003, the California State Water Resources Control Board (SWRCB), Underground Storage Tank Program updated two local-guidance (LG) letters. The SWRCB sends LG letters to local UST agencies to clarify program requirements. Two LG letters, one on enhanced leak detection (ELD) and one on statistical inventory reconciliation (SIR), were updated.

ELD is a third-party-certified test method capable of detecting both liquid and vapor releases at a leak rate of 0.005 gallons per hour. The original ELD LG (LG 161) discussed the requirement for UST systems with a single-walled component to be tested using ELD within 18 months of notification from the SWRCB and every 36 months thereafter. The SWRCB has now revised the LG (LG 161-2) to incorporate expanded ELD requirements (Assembly Bill 2481, Statutes 2002, Chapter 999). As of January 1, 2003, ELD is required at *all* UST systems located within 1,000 feet of a public drinking water well; double-walled UST systems must be tested

once using ELD by January 1, 2005. For additional information on the ELD requirement, visit: <http://www.swrcb.ca.gov/ust/docs/eld/index.html>.

Although not widely used in California, SIR is a monitoring method that may be used when approved by a local agency as part of a non-visual monitoring program [California Code of Regulations, title 23, section 2643(b)(3)]. The SWRCB has now revised the SIR LG (LG 139-2) to clearly identify the SIR reporting requirements, explain how to respond to fail/inconclusive results, and explain additional requirements that may be overlooked by SIR vendors or owners/operators.

Additionally, updated monthly and annual SIR summary report forms clarify the SIR requirements and the importance of reporting the SIR provider, method and version number, and SIR test results. SIR vendors and UST system owners/operators may use these forms to comply with reporting require [CCR, title 23, sections 2646.1(c) and (j)]. For additional information on SIR, visit:

http://www.swrcb.ca.gov/ust/docs/lgs/LG139_2.html.

Be sure to visit the California UST Program Web site (<http://www.swrcb.ca.gov/ust>) in the future to stay up-to-date on new guidance and requirements. You can subscribe to receive updates by visiting the California UST Program Web site and using the "Subscribe To" feature. ■

■ Surface Flux from page 18

Blayne Hartman, Ph.D., is a principal of HP Labs and the founder of TEG. He has lectured on soil vapor methods and data interpretation to over 20 state agencies and to all of the U.S. EPA regions. Blayne has contributed numerous articles to LUSTLine and authored chapters in three textbooks on soil vapor methods and analysis. This is his fourth article for LUSTLine on upward vapor migration.

For more information, e-mail Blayne at bhartman@hplabsonsite.com or check out his Web page at www.hplabsonsite.com.

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California Water District Sues Oil Companies for MTBE Contamination

The Orange County Water District (OCWD) is suing more than a dozen oil companies, MTBE manufacturers, and other responsible parties to recover funds needed to investigate, monitor, and remove MTBE and other gasoline oxygenate contamination in the soil, groundwater, and drinking water supplies within its service area. Leaking underground fuel storage tanks were identified as the primary source of the contamination.

The groundwater basin managed by OCWD provides most of the water supply for north and central Orange County—the most populous and developed part of the county. This water meets the needs of approximately 2.3 million residents. The District maintains that MTBE has significantly contaminated parts of the basin's shallow aquifer zone.

The suit contends that defendants named in the action "knowingly and willfully promoted and marketed gasoline containing MTBE and other oxygenates, when they knew or reasonably should have known that these compounds would reach groundwater, pollute public water supplies, render drinking water unusable and unsafe, and threaten the public health and welfare as they have done within the District." ■

Oregon's Mandatory UST Operator Training Underway

The Oregon legislature amended laws governing underground storage tanks in 2001 that added a requirement for mandatory operator training. Revised compliance rules for this training went into effect earlier this year. The rules provide that each regulated UST facility in Oregon that dispenses a regulated substance from a UST to a motor vehicle or container must employ trained personnel (i.e., a designated UST system operator) who can properly operate and maintain the UST system. Verification of training completion must be submitted to ODEQ by March 1, 2004. UST owners can receive training from a listed training vendor or pass the International Code Council's national UST System Operator examination and watch a video. For more information go to ODEQ's Web site at: www.deq.state.or.us/wmc/tank/USTOpTraining.htm. ■

OOPS!

Correction to PFP Table Published in LUSTLine #42

Table 1 (page 26) in the article, "Pay for Performance: Does It Work? The Data," in *LUSTLine* #42 had some errors in the South Carolina columns. This table highlights the corrected values. Although the correct numbers differ from the originally published numbers, the basic trend and dramatic improvement in time and price for PFP remains the same. ■

Table 1

COMPARISON OF COST AND TIME OF PFP VS. T&M

	EPA South Carolina		EPA Florida		Florida DEP Study	
	Average Cost	Average Time (Yrs.)	Average Cost	Average Time (Yrs.)	Average Cost	Average Time (Yrs.)
PFP	\$146,800	3	\$176,021	4.1	\$215,427	2
T&M/ Preapproval	\$215,110	7	\$376,308	6.7	\$300,255	3.5
Difference Between T&M and PFP	32%	57%	53%	39%	28%	43%

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EPA HQ UPDATE

Analytical Methods Fact Sheet Available

Analytical methods for petroleum hydrocarbons are well established; however, methods that were developed for analysis of petroleum hydrocarbons in water samples may or may not be appropriate for fuel oxygenates. A fact sheet, titled *Analytical Methodologies for Fuel Oxygenates* (EPA 510-F-03-001), outlines the potential problems of analytical methods for common fuel oxygenates and ways to address these problems. It has been distributed to states and regions and is available on the OUST Web site at www.epa.gov/oust/mtbel/omethods.pdf.

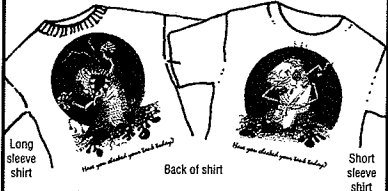
For more information, contact Hal White at (703) 603-7177.

Senate Passes UST Legislation

On Thursday, May 1, the U.S. Senate passed the Underground Storage Tank Compliance Act (S. 195) by unanimous vote. The legislation provides additional flexibility and authorization of appropriations for preventing and cleaning up releases from USTs. It also includes a dedicated authorization of appropriation for the cleanup of MTBE, mandatory inspection frequencies, additional enforcement tools, and operator training guidelines. Although the House has been working on its version of UST legislation, companion legislation has not been introduced. EPA OUST has been providing technical comments on the proposed legislation.

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