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L.U.S.T.LINE

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

And Now There Are None!

Goodbye Tank Farm, Hello Wind Farm

by Sofia Kaczor

This is the story of a small private electric utility, the Block Island Power Company (BIPCo), located in the Town of New Shoreham, a small island belonging to the smallest state in the United States, Rhode Island and Providence Plantations (Rhode Island).

BIPCo became the first Leaking Underground Storage Tank (LUST) site in New Shoreham. This UST facility was registered in 1984 with an inventory of 67 tanks, many of which were abandoned and/or leaking at that time. Several scientists and engineers in the LUST Program at Rhode Island Department of Environmental Management (RIDEM) were assigned to the case over the years and worked with the private utility to decommission 62 tanks. My turn came in 2010, when the last five 20,000-gallon diesel tanks were still being used to power the generators that provided electricity to Block Island's year-round residents and summer tourists. I oversaw the post-remediation monitoring of groundwater at the site until December 2017, when these tanks were removed.

At the same time, a major event was taking place on Block Island. The first offshore wind farm in the United States was being built approximately 3.8 miles southeast of the island. Between 2015 and 2016, a five-turbine, 30-megawatt capacity known as the Deepwater Wind Block Island Project was developed. On May 1, 2017, BIPCo switched from diesel power to wind power at 5:30 a.m. Electricity is now being harnessed by wind power!

About the Island

Block Island, also known as New Shoreham, is situated approximately 13 miles south of Point Judith, Rhode Island. The Italian navigator, Giovanni da Verrazzano first discovered the pear-shaped island in 1524. In 1614, the island was charted by the Dutch explorer Adrian Block, who named it for himself. The island was originally settled by the Niantic Tribe, later part of the Narragansetts, who called the island "Manisses"

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or "Little God's Island." In 1637, Massachusetts soldiers claimed the island from the Narragansetts and sold the land to sixteen proprietors in 1660. Some of the descendants of these sixteen original families are still represented on the island today. Block Island was incorporated by the Rhode Island general assembly in 1672, and the island government adopted the name "New Shoreham."

For the next 200 years, the history of Block Island was chaotic and full of unrest. During colonial times, the few permanent settlers were terrorized by privateers and pirates, who tortured and killed the inhabitants for their riches. The Narragansetts didn't fare any better as their population decreased from about 1,500 in 1662 to 51 in 1774. During revolutionary times, around 1775, the island was a target for deserters and criminals as well as for British raids. It was not until the late 19th century, coinciding with great economic growth in the United States, that Block Island was known as a grand Victorian Resort. The permanent residents prospered from fishing and farming to support the summer population as well as exporting their goods to the mainland.

Federal government funds were procured by Nicholas Ball and others for construction of the island's first deep water harbor in 1872. It was called "New Government Harbor," later known as Old Harbor, and it allowed for large vessels to dock and bring supplies as well as passengers. In 1887, Christopher Champlin obtained funds to cut a channel from Great Salt Pond and dredge it. This undertaking created the New Harbor, which was completed in 1899. These two new harbors attracted steamers from New York, Connecticut, and Rhode Island which arrived daily in the summer during the late 19th and early 20th centuries and brought such dignitaries as President Ulysses Grant on August 18, 1875. Many fashionable hotels were constructed during this time to accommodate the summer visitors.

After World War I, the resort industry declined, and the island residents again became self-supporting

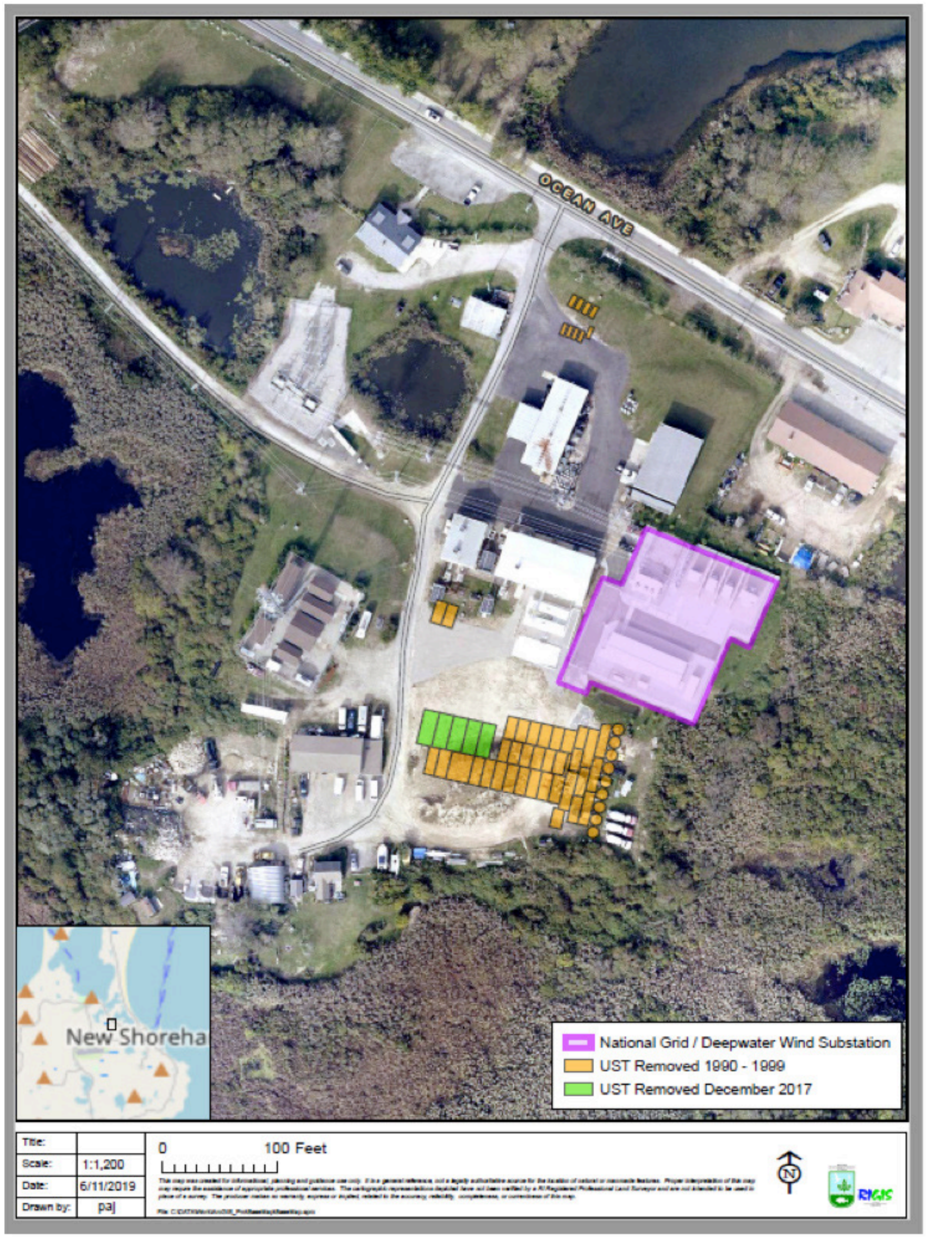

Figure 1. *Aerial view of Block Island Power Company (BIPCo) showing the location of the two former tank farms and the new National Grid/ Deepwater Wind Substation (this figure was prepared by Paul Jordan, Supervising GIS Specialist, RI DEM).*

L.U.S.T.Line

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through fishing and farming. The island was devastated by the hurricane of 1938. But after World War II, the island again became a desirable resort retreat again and one of the most popular summer vacation sites in the northeast to this day. (D'Amato and Brown, Block Island, 1999).

Regulatory History

BIPCo began operations around 1920 as a privately owned electric utility for island customers (Downie, 2008). It began operations with only four diesel generators in the basement of what is known today as Building No. 2. At that time, electricity was only provided during the day, operations were shut down at night.

1984-1990

BIPCo registered 67 USTs with RIDEM on December 1984. Of these, 51 tanks were part of a tank farm with an estimated capacity of 655,000 gallons. The remaining 16 tanks were mostly located in the fueling area near Ocean Avenue with a total capacity of 17,325 gallons. The diesel fuel in the tank farm supplied 13 generators via underground piping.

Records from BIPCo showed that several petroleum spills took place on the property between 1981 and 1986, ranging from 25 to 100 gallons. RIDEM identified contaminated soil near USTs during a 1985 inspection. Gasoline and fuel oil contamination was detected in the subsurface near Ocean Avenue in 1989. A groundwater remediation system, which included an interceptor trench and a pump-and-treat (P&T) recovery system, was installed in 1990 in the northern boundary of the property.

1991-2006

In December 1991, RIDEM issued BIPCo a Notice of Violation for the abandonment of 36 USTs, failed precision tests on multiple USTs, and evidence of soil and groundwater contamination near USTs at the site. RIDEM signed a Consent Agreement in June 1993 with BIPCo which required the utility to continue operating the remediation system near Ocean Avenue, remove 36 USTs not in use, and install a new recovery trench near the tank farm in the southern portion of the site. Groundwater remediation continued until 2006 when the P&T remediation systems were shut down. Between 1990 and 1999, a total of 62 USTs were removed from BIPCo. After 1999, four 20,000-gallon diesel USTs and one 20,000-gallon fuel oil UST remained on the property.

2006-2017

RIDEM required continued groundwater monitoring in the former gasoline/diesel fueling area. The UST Program required quarterly groundwater monitoring and annual precision testing as a variance for daily and monthly inventory recordkeeping for the remaining five USTs: four 20,000-gallon diesel USTs and one 20,000-gallon heating oil UST (off-site consumption). On December 2017, all five USTs and associated product lines were removed. Two 10,000-gallon diesel aboveground storage tanks

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Figure 2. *Northerly view of tanks 007 , 008, 009, and 010 (right to left) prior to being excavated in December 2017.*

Figure 3. *Last 20,000-gallon diesel tank being removed from the southern tank farm at BIPCo site.*

■ **Goodbye Tank Farm, Hello Wind Farm** *from page 3*

(ASTs) were then installed to supply backup generators.

Getting to "None"

BIPCo scheduled the closure of the five 20,000-gallon USTs at the end of 2017 to meet the single-walled deadline for these tanks. The work had to be scheduled around the availability of the Block Island Ferry to both bring equipment to and from the island and transport the tanks and contaminated soil to the mainland. Such construction/remediation work is only possible in the winter months, as the summer season is reserved for the tourism industry.

RIDEM was scheduled to make two visits to inspect the removal of the product lines on November 30, 2017 and the removal of the tanks on December 7, 2017. I travelled by ferry with LUST Program staff on both occasions. The flexible non-metallic double-walled diesel product lines, installed in 1999, were in very good condition. Soils beneath the product lines were screened with a Photo Ionization Detector and all results were non-detectable.

The tank removals took place a week later. On former rail tank cars, the tanks were brought to the island in 1960 and positioned against each other beneath a mounded area in the southern area of the property. According to the contractor that emptied the product from the tanks, these single-walled USTs had an interior coating to prevent corrosion. Prior to our arrival, a local contractor exposed the tanks and opened the eastern side of the mound. In delicately choreographed maneuvers, an excavator and a bulldozer were used to slowly "roll-out" the tanks from the "excavation." All five tanks, removed in one day, were in fair condition, with some scaling and rusting, but no discernible major holes or cracks. We all cheered the excellent work of the contractors and consultant for the efficiency of this closure, and for BIPCo having met the 2017 single-walled deadline.

Petroleum-contaminated soils were found beneath the three easternmost tanks, and this contamination was attributed to both known and unknown spills. Approximately 230 tons of petroleum-impacted soils were excavated and stockpiled for future disposal. Confirmatory soil analytical results from this eastern area showed that exceedances were still present beneath these tanks, as well as the former dispenser area.

Figure 4. *Photograph of the Block Island Wind Farm (http://dwwind.com/project/block-island-wind-farm/)*

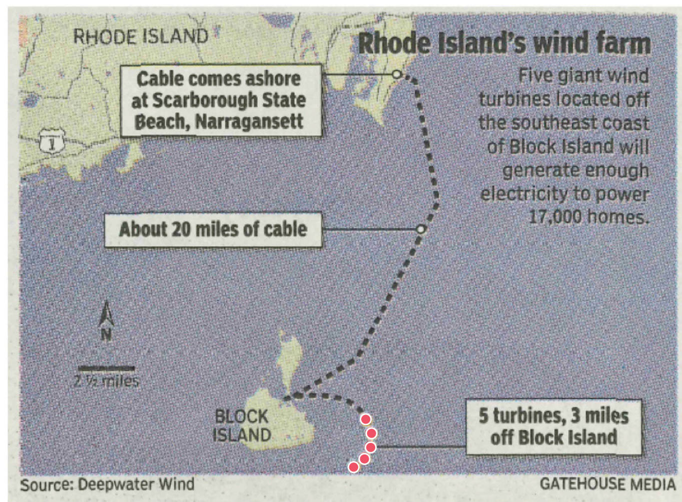

Figure 5. *From* Kuffner's Sunday Providence Journal *article "Standing Tall – RI Pioneers Ocean Energy" (May 3, 2015).*

A second round of soil excavation took place during February and March 2018. Approximately 150 tons of petroleum-impacted soils were removed, and the soil analytical results met the soil leachability objective for the future use of this site. Due to the space limitations of the ferry and the winter weather conditions, soil and tank off-site removals took place between January and March 2018. RIDEM received an UST Closure Assessment Report from SAGE Environmental, and on December 2018, RIDEM issued Closure Certificates for the four diesel and one heating oil USTs. In 2017, two new ASTs were installed for the back-up generators at BIPCo. And thus, was the end of USTs on Block Island.

The Deepwater Wind Block Island Project

In 1979, the U.S. Department of Energy installed an experimental wind turbine on the BIPCo property as part of NASA's initiative "to develop utility-scale wind turbines for electric power, in response to the increase in oil prices." Unfortunately, the wind turbine caused television interference and the residents of Block Island did not want the experiment to continue until they had cable television instead. The experimental wind turbine was therefore removed.

In April 2007, a state-commissioned study identified an area off the coast of Block Island as a potential location for offshore wind. Rhode Island requested proposals from offshore wind developers and selected Deepwater Wind from among seven

Figure 6. *View of National Grid / Deepwater Wind substation located in the "Alternative A" study area at the far end of this photograph. Existing BIPCo buildings are in the foreground. This picture was taken in February 2019.*

developers in September 2008. In July 2011, the Rhode Island Supreme Court upheld the Deepwater contract to sell electricity to National Grid. In November 2014, the project secured final permits, including key approval from the state Coastal Resources Management Council (*Providence Journal*, Sunday May 3, 2015).

The Deepwater Wind Block Island Project required that power generated from the five, 30-megawatt turbines be transmitted to the electric grid via a 21-mile transmission submarine-powered cable buried under the ocean floor and making landfall north of Scarborough Beach in Narragansett, Rhode Island. The system connects New Shoreham to the grid for the first time by replacing the diesel generators with power from the submarine cable (Sea2Shore cable) landing at Crescent Beach on Block Island's eastern coast. This project was a collaborative effort between Deepwater Wind, National Grid, BIPCo, elected officials, regulators, and the people of Block Island.

In 2012, when Deepwater Wind was negotiating with BIPCo a lease to construct a substation on BIPCo's property, RIDEM required that Deepwater Wind submit a proposed site investigation work plan. An environmental investigation dated June 26, 2012 was submitted to RIDEM to determine whether any soil or groundwater contamination existed in portions of the BIPCo property, where both the substation was to be constructed and new utility poles installed.

As a result of this investigation, an "Alternative A" study area was selected as the best location on the property to install the substation. RIDEM reviewed this environmental investigation. In December 2012, RIDEM's wetlands and LUST programs were tasked with confirming the results with a field visit. Three RIDEM staff members, including myself, were flown in by helicopter to confirm wetlands boundaries around the proposed substation (wetlands program) and proximity to the existing UST system and groundwater monitoring well network (LUST program). The "Alternative A" study area met all the environmental criteria as well as practical criteria due to its location near the BIPCo building, which housed the back-up generators and the existing power lines on the property.

Construction of the wind turbines began in 2015 at a cost of $290 million. The turbines were designed by Alstom Wind, stand 600 feet high, and can withstand a Category 3 storm. By August 2016, the Block Island Wind Farm was fully constructed and began commercial operations in December 2016. On May 1, 2017, BIPCo's President Jeffery Wright announced that:

> *"Block Island has been connected to the wind/farm/sea2shore cable and has shut down its generators" at 5:30 am (Block Island Times; 5-1-2017).*

Figure 7. *View of two on-site above-ground diesel tanks used for emergencies (February 2019)*

From Tank Farm to Wind Farm

In the past, the residents of Block Island relied solely on the electricity provided by diesel-powered genera-

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A Message from Carolyn Hoskinson

Director, USEPA's Office of Underground Storage Tanks

A Summer Potpourri of UST News

Who doesn't like to kick back and take it easy during the lazy days of summer? But even in the summer, we here in USEPA's Office of Underground Storage Tanks are tending to all things related to underground storage tanks (USTs). Below is a potpourri of UST news covering what's been going on in the UST world recently:

- *Progress updating state, territorial, and District of Columbia (collectively referred to as states) regulations*
- *Changes to semiannual performance reporting*
- *Issuing release detection standard test procedures*
- *Storing E15 in USTs*
- *North Carolina's UST backlog reduction initiative*
- *Loading and unloading exclusions in financial responsibility*

Progress Updating State Regulations

Let me start with a hearty thank you to states for all your work with our USEPA regional UST programs to renew state program approval (SPA) based on the 2015 federal UST regulation. I know the going is sometimes slow and there are many hurdles—administrative and otherwise—to overcome, but together we are successfully moving forward on this. By my accounting, the current nationwide status of the regulations and program approval is:

- 42 states updated their regulations to incorporate the revised 2015 federal UST regulation
- 23 states have pending applications with USEPA for state program approval under the 2015 federal UST regulation
- 4 states—Oklahoma, Utah, North Dakota, and Colorado—have approved UST programs under the 2015 federal UST regulation.

For those states who have not yet updated their regulations to incorporate the 2015 federal UST regulation, time is of the essence. As you probably know, if you want to maintain state program approval, it is not permissible to have state regulatory compliance dates beyond October 2021. That means it is imperative to finalize your regulations soon because that gives the regulated community more time to come into compliance with your state requirements.

Your diligence in this area is crucial because it will get us to the new normal nationally, giving UST owners and operators, UST service companies, UST inspectors, and others clarity and certainty on what requirements apply and where. Keep up the good work, and let's keep working to turn the SPA map blue! To view our SPA map, see USEPA's website *www.epa.gov/ust/state-underground-storage-tank-ust-programs#which.*

Changes to Semiannual Performance Reporting

Have you seen the new look of USEPA's semiannual report of UST performance measures? Effective for our mid-year 2019 report, we revised some performance measures to reflect changes in the 2015 federal UST regulation. One of the changes is that states are reporting on either significant operational compliance (SOC) measures or new technical compliance rate (TCR) measures. As states' regulatory compliance dates pass, they are switching from reporting SOC measures to reporting TCR. By October 2021, every state will have transitioned to TCR reporting; until then, we will see variable reporting. We are also now tracking compliance with operator training, financial responsibility, and walkthrough requirements. In addition, we added a measure to track closed hazardous substance UST systems.

Here are some results from the mid-year 2019 report. This is the first time in seven years that we saw an increase in cleanups completed nationally from one mid-year report to the next. For mid-year 2019, we reached 4,141 cleanups completed compared to mid-year 2018 of 3,967. We saw a decrease in confirmed releases, which was an unexpected outcome: at mid-year 2019 we confirmed 2,442 releases and at mid-year 2018 we confirmed 2,829 releases. Given that several states passed their compliance dates, nationally we expected a short-term increase in confirmed releases due to testing of new areas of tanks, such as spill buckets and sumps. This is an interesting trend to watch. And at mid-year 2019, the combined TCR is 48.8 percent and combined SOC is 70.2 percent. See USEPA's website *www.epa.gov/ust/ust-performance-measures* for the 2019 mid-year report and the 2018 UST and LUST performance measures definitions.

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For reporting on performance measures going forward, USEPA is encouraging states to comment on the number of field-constructed tanks and airport hydrant systems in their total tank universe count. Since USEPA is not tracking these numbers separately, it is helpful if states provide that information as comments. And, of course, we will continue to see the transition of reporting on compliance from SOC to TCR.

Issuing Release Detection Standard Test Procedures

USEPA recently issued revised release detection standard test procedures, commonly referred to as protocols. We originally developed the protocols in 1990, and in May 2019 we issued revised versions that address new information and technology, as well as incorporate requirements of the 2015 federal UST regulation.

One important point to highlight about the 2019 protocols: vendors with release detection equipment evaluated using the 1990 protocols and listed on the National Work Group on Leak Detection Evaluations' (NWGLDE) website are not required to re-evaluate their equipment with the 2019 protocols and relist with NWGLDE. But, going forward, vendors who modify their equipment and choose to have that equipment evaluated using USEPA's protocols must ensure the evaluations use the 2019 protocols.

In addition, the 2019 protocols address release detection equipment performance when used with increased levels of ethanol in fuel blends. The 1990 protocols focused on the performance of release detection equipment used with non-alcohol blended gasoline and diesel fuel products, which were the prevalent fuels at that time.

Please be aware that high water levels sometimes associated in UST systems that store higher ethanol fuel blends such as E85 can affect certain operating principles used by certain legacy release detection equipment. This could make legacy release detection methods evaluated with the 1990 protocols less reliable. For additional information about the 2019 protocols and to access them, see USEPA's website *www.epa.gov/ust/standard-test-procedures-evaluating-various-leak-detection-methods*.

Storing E15 In USTs

Another topic of interest is the rapid growth of retailers selling E15, which is gasoline blended with up to 15 percent ethanol. E15 was offered at just a handful of stations operating five years ago, but now is offered at more than 1,600 stations in the United States, mostly at major chains that are rapidly building new stations.

Regulators should be aware there may be even further potential interest in retailers offering the fuel this year. On May 31, 2019, USEPA finalized regulatory changes that allow E15 to take advantage of a particular waiver that currently applies to E10 during the summer. This means E15 may be sold all year across the country, so more owners and operators may be interested in offering it for their retail customers or fleets. To view USEPA's compliance advisory about E15 and compatibility requirements in 40 CFR 280.32, see our website *www.epa.gov/ust/compliance-advisories-about-2015-underground-storage-tank-regulation.*

Regulators should remember that, under the federal UST regulation, owners and operators who will store E15 must notify their implementing agencies in advance, demonstrate that their systems are compatible with the fuel, and keep relevant records. USEPA established this requirement in the 2015 federal UST regulation because higher levels of ethanol can be more aggressive toward some materials in UST systems. Owners and operators who did not install systems specifically to store E15 or E85 but plan to store them must ensure their systems only use compatible equipment designed for those fuels. Owners and operators also must pay close attention to pipe dope and sealants, because USEPA understands that sealant options compatible with higher levels of ethanol were unavailable in the market until about ten years ago. See three questions regarding this topic on USEPA's website *www.epa.gov/ust/underground-storage-tank-ust-technical-compendium-about-2015-ust-regulation* (scroll to Compatibility)

North Carolina's UST Backlog Reduction Initiative

Reducing our leaking UST backlog continues to remain a priority for the national UST program, and some states are undertaking efforts focused on that priority. For example, North Carolina's initiative, discussed below, is making a difference in their cleanup results.

In October 2018, North Carolina Department of Environmental Quality's (DEQ) UST Section began a proactive approach and initiative to reduce their backlog of open UST release sites. North Carolina's UST backlog reduction initiative combines dedicated federal and state money along with realignment of North Carolina DEQ personnel to ensure the project's success. North Carolina's UST Section will use just over $1 million in federal fiscal year 2017 LUST cleanup money along with $1 million of state money to perform desk file reviews and limited site assessments of UST backlog release sites. Because this initiative is a priority, North Carolina's UST Section is dedicating 41 of their UST incident managers to work on this either full time or part time.

As part of this initiative, approximately 1,666 backlog sites will be reviewed and categorized according to the level of work necessary and the available money. North Carolina's UST Section estimates that approxi-

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mately 200-300 releases may be eligible for an administrative closure by using the state's Notice of Residual Petroleum deed restriction as an institutional control to close certain UST releases. North Carolina anticipates a potential increase in UST cleanups completed resulting from this initiative to approximately 600 for FY 2019.

This anticipated increase is almost 30 percent higher than their historical cleanups completed annually. The initiative is showing signs of success already, with approximately 375 closures achieved at mid-year 2019. North Carolina's initiative contributed to the national UST program achieving an increase in cleanups completed nationally from one mid-year report to the next for the first time in seven years.

Loading and Unloading Exclusions in Financial Responsibility

We recently received inquiries about loading and unloading exclusions or endorsements meeting federal financial responsibility requirements, so I thought it would be useful to reiterate USEPA's position. Since the 1988 UST regulation established financial responsibility requirements, USEPA has taken the position that financial responsibility mechanisms—for example, insurance policies, state funds, letters of credit, or surety bonds—must cover all releases UST system owners and operators are liable for reporting and cleaning up under 40 CFR Part 280. These releases could include loading and unloading activities if the releases trigger the reporting and cleanup requirements for spills and overfills under 40 CFR 280.53.

An insurance policy or other FR mechanism that does not cover releases from loading and unloading activities does not, on its own, meet the federal financial responsibility requirements. For more on loading and unloading, as well as other financial responsibility questions, see USEPA's website *www.epa.gov/ust/ust-technical-compendium-financial-responsibility* and scroll to question 12.

That's It...For Now

That's a wrap for this UST news update. As always, I am extremely grateful to our UST partners for their effort in preventing and cleaning up UST releases. And please continue your exceptional work to protect our environment from underground storage tank releases. ■

■ Goodbye Tank Farm, Hello Wind Farm *from page 5*

tors. Now they can receive electricity in three ways: by wind power, the submarine cable from the mainland, and from back-up generators powered by two on-site ASTs. This project substantially reduced the electrical costs for the island's ratepayers, costs which exceeded 60 cents per kilowatt/hour and were the highest rates in the country! The switch from diesel-power generators to energy provided by the wind turbines saved BIPCo nearly one million gallons of diesel fuel annually!

So is this the only power source now? YES! Two ASTs are used for emergencies only. Since May 1, 2017, all electricity needs on Block Island are met by the energy generated from the Block Island Wind Farm—the nation's first off-shore wind project! The UST removals of 2017 were successful in removing most of the petroleum-impacted soil at the old tank farm area. Presently, groundwater monitoring continues near Ocean Avenue in the former fuel-dispensing areas until compliance with the groundwater quality standards is achieved. Post-excavation groundwater monitoring is being required at the southern tank farm area prior to site closure. ■

Figure 8. *The last 20,000-gallon diesel tank leaves the BIPCo premises to be loaded on the Block Island Ferry for disposal on the mainland.*

Sofia Kaczor is a former Principal Environmental Scientist with the LUST Program of the Rhode Island Department of Environmental Management. She can be reached at s.kaczor@verizon.net. *Sofia Kaczor would like to thank the BIPCo officials for their determined cooperation in this project and for kindly assisting RIDEM staff during their scheduled inspections on Block Island.*

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Tank-nically Speaking

by Marcel Moreau

*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.**

Inspecting Overfill-Prevention Equipment

Some Infrequently Asked Questions

Over the last century, many of our buried petroleum storage system problems were due to a pervasive attitude that lay somewhere between "bury it and forget it" and "out of sight, out of mind." Our old steel storage systems, unprotected from corrosion, also suffered from the human propensity to believe that "ignorance is bliss."

While the 1988 federal UST rules substantially addressed UST equipment problems, they did little to change these old attitudes. The 1988 rules did not require any testing or inspection of equipment (with the exception of cathodically protected components and line leak detectors). The 2005 UST operation and maintenance manual published by USEPA recognized the need for UST personnel to pay attention to their UST systems, but it was not until the 2015 federal rule revisions that periodic inspection and testing of critical UST equipment became obligatory rather than left to the discretion of the tank owner or operator.

In this article, I want to review the nuts and bolts associated with the functional inspection and testing of overfill-prevention equipment. I've written about the frailties and foibles of overfill-prevention equipment a number of times over the years, and so I'm happy to see that this equipment is getting some much-needed attention. But some loopholes remain with respect to how we are approaching overfill prevention and, if we're not careful, some of this newfound attention could create its own problems.

If you need an introduction (or a refresher) on how overfill-prevention devices work, I suggest you look up "What Every Tank Owner Should Know About Overfill Prevention," in *LUSTLine* Bulletin 21, December 1994, in the *LUSTLine* archives available on the NEIWPCC website (*http://neiwpcc.org/our-programs/underground-storage-tanks/l-u-s-t-line/l-u-s-t-line-archive/*)

What the Federal Rule Says About Overfill-Prevention Equipment Inspection

The 2015 amendments to the federal rule include a requirement that overfill-prevention equipment be inspected every three years. The goals of the inspection are to ensure that:

- the overfill equipment is set to activate at the level specified in the rule, and
- the equipment will activate at that level and affect the delivery by restricting the flow, shutting off the flow, or triggering an alarm.

The inspection can be conducted according to:

- the equipment manufacturer's instructions,
- a code of practice developed by a nationally recognized organization, or
- requirements set by the implementing agency.

What Inspection/Testing Procedures Are Out There?

Overfill equipment manufacturers' inspection/testing procedures, when they exist, are typically simplified and not comprehensive. The federal rule notes that equipment manufacturers' instructions can be used to fulfill inspection requirements only if procedures that meet the rule requirements described above actually exist.

With regard to the second option for inspection procedures, the federal rule specifically references Petroleum Equipment Institute publication PEI RP 1200, *Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection, and Secondary Containment Equipment at UST Facilities* as an industry code of practice that may be used to fulfill the equipment inspection and testing requirements of the rule. RP 1200 is reasonably detailed in its description of the procedures and comprehensive in its criteria for evaluating whether equipment passes or fails.

Note that RP 1200 is available for purchase on the PEI website, but the checklists that can be used to document the inspection and testing procedures are available for download for free at *www.pei.org/rp1200*.

In the interest of brevity, I'm going to limit this discussion to overfill equipment typically used in USTs storing motor fuel and omit devices commonly found in heating oil USTs. I'll also address only the most commonly used types of overfill devices produced by the more prominent manufacturers of petroleum equipment.

Inspecting Overfill Alarms

Overfill alarms are the most flexible type of overfill prevention. Alarms can be used for both gravity and pressure deliveries, and have no

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■ Inspecting Overfill Protection Equipment *from page 9*

limitations with regard to what other equipment may be used in the UST. Despite this they are not in common use, perhaps because their effectiveness depends entirely on the quick response of the delivery driver when the alarm is triggered. Most overfill alarms at motor-fuel facilities are connected to automatic tank gauges, so the discussion that follows is limited to this type of alarm.

What the Federal Rule Requires Alarms to Do

The overfill alarm must alert the delivery driver when the tank is at 90 percent capacity or one minute before the tank is overfilled.

■ Step One: Is the Alarm Working?

What the Manufacturers Say

I'm not aware of any alarm manufacturer's explicit inspection/testing instructions intended to meet the requirements of the 2015 federal rule. Some common alarm features that could be used for testing include the following:

- Many alarms incorporate an "acknowledgement" switch that allows the delivery driver to turn off the alarm. Some of these acknowledgement switches incorporate a "test" button. This button can be used to activate the alarm, but it only verifies that power is being supplied to the alarm. The test button does not verify that the alarm is connected to a tank gauge.
- Tank gauges activate alarms by operating electrical switches called "relays" that complete a circuit and turn the alarm on. By pushing buttons (or touch screens on more recent tank gauges), the relay that controls the alarm can be manually activated. This allows verification that the alarm is connected to the tank gauge and can be activated by the tank gauge. It does not verify that the tank gauge has been programmed to sound the alarm.
- The setup programming of the tank gauge can be reviewed to ascertain that when the programmed overfill level is reached, the relay controlling the external alarm will be activated.

The activities described in the last two bullets above provide reasonable assurance that the external overfill alarm will sound at the correct level. But they are not described as the inspection/testing procedure to follow in any manufacturer's literature that I have seen, So I don't believe they qualify as "manufacturer's instructions" for purposes of meeting the inspection/testing requirements of the regulations.

What RP 1200 Says

As an initial step, the RP 1200 procedure includes verification that the alarm can be activated by operating the relay on the tank gauge as described in the second bullet above. RP 1200 goes beyond manual activation of the relay and specifies that the overfill alarm is to be tested by removing the tank-gauge probe and manually moving the product float up the probe until the alarm is activated.

■ Step Two: Is the Alarm Set to Operate at the Appropriate Level?

What the Manufacturers Say

As far as I can tell, manufacturers do not provide any specific methodology for verifying the level at which the overfill alarm will activate. One approach would be to view or print the tank-gauge setup. The setup should indicate the level at which the alarm activates and the relay which will operate when the fuel level reaches the overfill alarm level. Tank gauges reliably follow their programmed instructions, so reviewing the setting for the overfill alarm should provide reasonable assurance that the alarm is properly set. However, this approach does not confirm that the ATG probe has been properly calibrated and is accurately reading the level of fuel in the tank.

What RP 1200 Says

RP 1200 makes no assumptions about the programming of the tank gauge or the calibration of the tank-gauge probe. The RP specifies that once the point on a probe where the overfill alarm is triggered has been located, the distance from the bottom of the probe to the product float is measured. Using the appropriate tank chart, this distance measurement is then used to determine the tank volume at that level. Calculations are then made to verify that the level where the overfill alarm is activated is in fact no more than 90 percent of the tank capacity.

■ Infrequently Asked Overfill Alarm Questions

What if the Overfill Alarm is Set to Activate "One Minute Before Overfill"?

What if a tank owner says the overfill alarm is set to activate one minute before the tank overfills? This is allowed in the federal rule, although this alternative level for triggering an overfill alarm has not been adopted in all states. Applying this standard requires knowing the rate at which fuel flows into a tank during a delivery, or making some assumptions about what the maximum fuel flow rate might be. Neither manufacturers' instructions nor PEI's recommended practice on UST installation, RP100, provide guidance on how this overfill alarm option should be installed. This raises the issue of whether this is a viable overfill prevention option at all, but that is a topic for another day.

RP 1200 takes a more conservative approach to overfill alarms than the federal rule. If RP 1200 is followed, any alarm that is activated above the 90 percent level if the tank fails the inspection.

I'm not aware of any overfill alarm manufacturer that provides a procedure that effectively tests whether the alarm meets the one minute before overfill option in the federal rule. If neither the equipment manufacturer nor RP 1200 provides a procedure, then it would be up to the implementing agency to develop or approve a procedure for meeting this overfill option in the rule.

Does the Tank-Gauge Probe in Each Tank Have to be Tested?

RP 1200 requires that the probe in each tank be tested to be sure it activates the overfill alarm at the 90 percent level. In the absence of manufacturer's procedures, the RP 1200 procedure or a procedure approved by an implementing agency would need to be followed.

How Loud or Bright Should the Alarm Be?

The federal rule specifies only that the alarm must "alert" the driver. PEI's RP100 states only that the alarm should be in close proximity to the delivery operator. Manufacturers' alarms generally include both a visible flashing light and an audible alarm, and some state regulations require both an audible and visual alarm. There are no specifications in the rule as to how loud the audible alarm must be, how long the alarm must sound, or how bright the light should be. Some manufacturers have alarms where the loudness can be adjusted, and others sell low-intensity alarms for "quieter" locations and louder alarms for noisier locations. RP 1200 does not address this issue. To my knowledge, there are no standards for how loud or bright an alarm must be to "alert" a delivery driver, and there is no test procedure that I have found that evaluates whether an alarm is loud or bright enough to "alert" the delivery driver.

How Long Does the Alarm Have to Sound?

The audible alarm on some manufacturer's devices can be set to sound anywhere from zero to 60 seconds. Is a one-second audible alarm long enough to alert the driver? It seems to me that the alarm should be required to sound for a minimum amount of time, say 30 seconds, and be loud enough to be very obnoxious to the driver and everyone around. The driver can always use the acknowledgement button to silence the alarm sooner than 30 seconds (after he has stopped the fuel delivery, of course). Manufacturer's instructions that I have reviewed provide no guidance as to how long the alarm should sound, and RP 1200 is silent as to the duration of the alarm. It would be up to the implementing agency to set a limit on the minimum duration of the alarm.

Does there Need to be an External Overfill Alarm for Each Tank at a Facility?

Every retail gasoline facility with an overfill alarm that I have seen has had a single external alarm unit, even though there were multiple tanks and/or multiple tank compartments at the facility. Is this enough? Once an external overfill alarm has been activated and acknowledged, it will not sound again if another tank at the facility is filled beyond the 90 percent level unless the fuel level in the tank that first caused the alarm to sound has been lowered to less than the 90 percent level.

I am familiar with a case where a delivery driver used the tank gauge to obtain his before delivery fuel readings. The facility had four, 4,000-gallon tanks. He saw that the volume of premium fuel he had on the truck would exceed the 90 percent level of the premium tank. But he also saw that he would only be about 250 gallons over the 90 percent level, so there was plenty of room in the tank to hold the fuel without exceeding the premium tank capacity. In other words, the delivery driver expected the overfill alarm to go off, but he knew that the premium fuel would still fit in the tank.

He also had regular fuel on his truck. There were two regular fuel tanks at the facility, one nearly empty and one nearly full. Unfortunately, the driver misidentified the regular tanks and delivered 2,000 gallons of regular fuel to the tank that was already just shy of 90 percent full and had only 425 gallons of remaining capacity.

The driver connected his hoses and began delivering fuel to the premium and the regular tank at the same time. The overfill alarm sounded. The driver disregarded the alarm because he thought it was for the premium tank and he knew the fuel was going to fit in the premium tank. Because there was only one alarm for all four tanks at the facility, once the alarm was silenced it never sounded again.

The drop tube shutoff valve in the already full regular tank that the driver connected his hose to didn't work (it likely had a stick in it) so the tank filled to capacity. The pressure of the fuel entering the tank popped the cap off the tank-gauge-probe riser (the cap may have been only loosely fastened to begin with), and fuel poured into the submersible pump sump which also contained the tank-gauge-probe riser. The fuel in the sump set off a sensor, then filled and overflowed the containment sump, releasing roughly 1,500 gallons into the tank backfill. There was not a sign of anything wrong aboveground.

Most gas stations receive fuel in multiple tanks or multiple tank compartments when a delivery is made, but the external overfill alarm will only sound once in the course of a typical delivery no matter how many tanks are filled beyond the overfill alarm level. Does overfill prevention that only alerts the driver to the first instance of a tank being filled beyond the overfill limit meet the requirements of the rule?

Inspecting Ball-Float Valves

Ball-float valves are the black sheep of the overfill-prevention world. They have never been very effective at what they are supposed to do (in my opinion). PEI's recommended practice for installation of underground storage systems (RP 100) first recommended against using ball-float valves for overfill prevention in the 2005 edition. USEPA got on board in the 2015 rule amendments with a prohibition against installing new or replacement ball-float valves. The three-year inspection requirement will hasten the demise of ball-float valves from the UST world, but even this requirement is likely to have some unwanted side effects that persist for a long time.

What the Federal Rule Requires

Ball-float valves must restrict the flow of fuel into the tank when the fuel level reaches 90 percent of tank capacity or 30 minutes before the tank is overfilled.

■ Step One: Is the Ball-float Valve Working?

What the Manufacturers Say

Most ball float manufacturers are silent about inspection procedures, although one does describe the following maintenance procedures: "…remove and inspect the valve for damage, contamination, corrosion, freedom of movement of the ball float, and check the bleeder orifice for proper airflow. Replace if damaged or corroded."[1] Although these instructions are available on the internet as I write, they are dated 2002. The instructions have not been updated to reflect that replacement of the ball float as an overfill prevention device is no longer permitted by the federal rule.

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What RP 1200 Says

RP 1200 requires removal and visual inspection of ball-float valves. The ball-float valve will fail the inspection if it cannot be removed. The inspection includes checking the integrity of the ball, the free movement of the ball, the presence of corrosion that may affect the operation of the valve, and the fact that the small bleed hole is open. In addition, RP 1200 includes factors to ensure that the ball valve will operate as intended, including:

- Visual inspection of all tank-top fittings to be sure they are leak free and vapor tight
- Verification that the tank does not use suction pumps with air eliminators to dispense fuel
- Verifying that coaxial Stage I vapor recovery is not present
- Verifying that any remote fills include a "trap door" device on the direct fill.

Figure 1. *Removing overfill devices may reveal damage that is not otherwise obvious. Close inspection is required to detect ball floats that are stuck in their cages (left photo) or punctured so that they don't float (right photo).* Photos courtesy of Spruce Wheelock.

■ Step Two: Is the Ball-float Valve Set to Operate at the Appropriate Level?

What the Manufacturers Say

Manufacturers' installation instructions generally direct the technician to consult the appropriate tank chart to determine the correct length of the ball-float valve to activate the ball float at 90 percent of tank capacity. I have not found any inspection or maintenance procedures for ball-float valves that check to see whether it is the appropriate length.

What RP 1200 Says

RP 1200 defers to the ball float manufacturer's installation instructions to determine whether the valve is the correct length. RP 1200 inspection procedures are limited to the "90 percent of tank capacity" criteria in the regulations. Any ball float that operates at a level in the tank that is higher than 90 percent would fail the RP 1200 inspection.

■ Infrequently Asked Questions

What if the Ball Float is Set to Operate 30 Minutes Before the Tank Overfills?

One manufacturer does provide a ball-float valve that is specifically intended to meet the federal alternative ball float standard of "30 minutes before overfilling." This valve has a smaller bleed hole (1/16 inch rather than 1/8 inch) and is supplied with an O-ring to help ensure that there is no leakage of vapors where the body of the valve screws into the extractor fitting. The manufacturer has calculated that the appropriate length for this valve is 308 gallons less than the full capacity of the tank.[2] The manufacturer acknowledges that this calculation is dependent on the head pressure created by the height difference between the surface of the liquid in the truck and the surface of the liquid in the tank.[3] However, there is no information on what the assumed head pressure was for their 308 gallon calculation or how to make the calculation for different head pressures.

I can see where variables like tank burial depth and whether the fuel in the truck is near the top or bottom of the truck compartment could significantly affect the accuracy of this calculation. By not providing necessary guidance in making this calculation we have a very serious deficiency that makes it impossible for a typical tank technician to accurately verify that this type of ball valve is the correct length.

A ball-float valve designed to operate 30 minutes before the tank is overfilled would fail the RP 1200 inspection because it would operate above 90 percent of tank capacity, the sole criterion that RP 1200 uses.

As I see it, the "30 minute before overfill" criterion for ball-float valves could only be used if a state agency were to approve or develop an inspection procedure specifically for this purpose.

What If a Ball-float Valve Is Probably Installed, but Not Accessible?

In the early 1990s, it was fairly common for ball-float valves to be installed with no means to access them once the installation was complete. After all, there was no inspection requirement back then, and ball floats were simple devices, so what could possibly go wrong? Many such valves would require excavating to the tank top to locate and remove the valve. Video inspection of the inside of the tank could also be used to identify whether a ball-float valve was present. But such options are costly and not likely to be attractive to the typical UST owner. An attractive alternative would be to simply leave the ball float in place (not knowing whether the ball float is still in operating condition or at what tank capacity it is set to operate) and install a drop tube shutoff valve. Problem solved!!?? Not quite. See the next question.

What If There's a Ball Float, But the Technician Can't (Or Doesn't Want to) Remove it?

Even where extractor fittings have been installed to allow the removal of the ball float, many of these extractor fittings have been undisturbed for many years and are likely to be difficult, if not well-nigh impossible, to remove. Manufacturers are generally silent about this scenario, while RP 1200 clearly states that a ball float that cannot be removed fails the inspection. What to do then? None of the options are very attractive:

- **Option 1:** Excavate to the tank top and/or do whatever needs to be done to permanently remove the ball float.

This is likely to be the least attractive option to the tank owner, but it appears to me to be the only option that is consistent with RP 1200 and is the safest option in terms of effective overfill prevention.

- **Option 2:** Ignore RP 1200, leave the ball float alone, and install alternate overfill prevention.

If an overfill alarm were installed, the ball float would not interfere with the alarm so that would be a viable, though potentially expensive, option. If an alarm is installed, some form of notice should also be provided to delivery drivers to let them know that in addition to the alarm a ball float is also present.

If a drop tube shutoff valve were installed to provide an alternate form of overfill prevention, the situation is more complicated. If the drop tube shutoff were installed at the usual 95 percent of tank capacity, the ball float (if installed at 90 percent of tank capacity) would close before the level where the drop tube shutoff valve operates. This would slow down the rate of fuel delivery such that the drop tube shutoff valve would be ineffective (see the "Why are ball floats and drop tube shutoff valves such an issue?" question below if you don't understand why this is so).

To avoid the situation of the ball float rendering the drop tube shutoff valve ineffective, the drop tube shutoff would need to be set to activate at somewhat less than 90 percent of tank capacity. However, this runs afoul of the RP 1200 procedure which states that when a ball float and drop tube shutoff valve are both present, the inspection fails if the ball float operates before the tank is 95 percent full.

The RP 1200 procedure does not allow for the situation where the drop-tube shutoff valve is set to operate at less than 90 percent of tank capacity. Perhaps this is because I can envision a scenario where a technician on a subsequent inspection finds the drop-tube shutoff valve set at something less than 90 percent of the tank capacity and concludes that the valve is set incorrectly. He then raises the valve to the 95 percent level thinking he has done a good deed for the tank owner, when he has actually just disabled the drop-tube shutoff valve and made the ball float the overfill prevention device again—assuming the ball float is still operational—much to the surprise of any delivery driver who fills the tank beyond the 90 percent level.

- **Option 3:** Ignore RP 1200, and if the ball float is visible, punch the ball out of its cage with a gauge stick.

This is likely to be the most attractive option to the tank technician and the least costly for the tank owner. The assumption is that, by removing the ball, the technician has disabled the ball float—which in his mind is equivalent to removing it altogether.But this is not the case. See the next question for details on why this is so.

Can a Technician Just Knock the Ball Out of Its Cage to Disable the Ball-Float Valve?

For valves that do have an extractor and are accessible from grade, the simplest option listed above is to simply poke the ball out of its cage. This will appeal to many technicians who, understandably enough, assume that the ball float has now been disabled and there is no need to remove it.

While a "ball-less" ball float no longer functions as designed, it can still cause serious problems, as the vent for the tank now extends some distance below the tank top. As soon as the fuel level exceeds the bottom end of the float vent valve, the remaining air/vapor mixture in the tank ullage will be trapped and have no route to escape (assuming all the tank-top fittings are tight and the cap on the tank-gauge-probe riser does not pop off). Fuel will immediately flow up into the vent piping as this is the only route for it to take. If the vent piping has been manifolded (typical at locations where Stage II vapor recovery was installed), fuel will flow into the adjacent tank(s). If there is no vent manifold, fuel will flow into the vent riser, the Stage I vapor recovery hose (if present), and back up into the product delivery hose as well.

The perplexed delivery driver will find himself back in the bad ol' days before tanks had any form of overfill prevention and a tank was filled beyond its capacity: lots of excess fuel in the hoses and no place to put it. Nowadays, however, there is a more environmentally friendly (though not particularly safe) way to deal with this situation than simply emptying the hoses into the dirt around the fill pipe. Removing or loosening the cap on the tank-gauge-probe riser will allow the tank to vent through the riser and the delivery hoses to drain. If the fuel in the tank is gasoline, removing the tank-gauge-probe cap releases significant quantities of gasoline vapor at grade level, posing a risk of fire.

RP 1200 notes that when a ball float is removed, the entire assembly must be removed. Implementing agencies would do well to emphasize this message repeatedly to tank technicians in their jurisdiction.

What if There Is More Than One Ball Float?

Up until the mid-1990s (and perhaps even later in some areas), it was common practice to have multiple openings in the tank top to handle gasoline vapors. There would be the traditional vent, another opening for Stage I vapor recovery, and per-

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haps a third opening for linking the tank ullages together when Stage II vapor recovery was installed. Each of these openings would be equipped with a ball-float valve. Overfill prevention using ball-float valves would only be effective if all of these ball-float valves were operating properly. All of these ball floats would be subject to the inspection requirement of the rule. But unless each ball-float was installed with an extractor fitting, it would be difficult to tell how many ball floats there were. A video inspection could answer the question of how many ball floats were present, but then what do you do? Excavate the tank top and remove them all? This is getting expensive.

The argument could be made that as long as the ball-float below the Stage I vapor recovery fitting were removed, and the Stage I vapor recovery hose were connected for *every* delivery, the other ball floats could be left in the tank because they would be bypassed during the delivery process and would do no harm. It would be up to the implementing agency to decide whether this approach was acceptable. PS. Don't forget to install new overfill prevention equipment after dealing with all those ball floats.

What if the Ball-Float Is Installed in a Manway in the Tank?

Manway covers are typically 4 to 6 inches above the top surface of the tank shell, so this additional height must be taken into consideration when determining the appropriate length for the ball-float valve. Installation instructions for ball-float valves are pretty good about taking this into account, but it could be difficult to tell if a manway is present during an inspection unless the manway is in a containment sump.

The presence of a manway could be determined by measuring the distance from the bottom of the tank to the top of the ball-float riser and subtracting the distance from the top to the bottom of the ball-float riser. This calculation should yield the tank diameter. If this measurement is several inches greater than the tank diameter indicated on the tank chart, a manway is likely present.

No manufacturer's inspection procedure that I have reviewed checks for the presence of a manway when inspecting a ball float. RP 1200 is also silent as to establishing whether a manway might be present when inspecting ball-float valves. If an implementing agency is concerned about improperly placed ball-float valves when manways are present, the agency would need to create or approve a procedure to check this.

Figure 2. *The effort required to remove drop tube shutoff devices that were installed many years ago may destroy the device. Photo courtesy of Ed Kubinsky.*

Inspecting Drop-Tube Shutoff Devices (Flapper Valves)

Much of the attention regarding testing overfill prevention devices has focused on drop-tube shutoff devices commonly referred to as flapper valves. The big issue seems to be whether these need to be removed in order to be inspected. Manufacturers seem to favor inspection without removal, with one manufacturer developing a device specifically designed to be inspected without removal, while other manufacturers have come up with modifications of existing devices to enable some form of inspection without removal.

The primary argument against removal seems to be that it is difficult, so inspection without removal will be easier and faster. The primary argument for removal seems to be that only by visual inspection can you really see whether there are any conditions (corrosion, broken pieces, altered components, etc.) that would prevent the operation of the valve.

There is little doubt that in the case of drop tubes that have been installed and undisturbed for many years, it is quite likely that the device will be destroyed in the removal process. This is most often due to corrosion products accumulating in the narrow space between the aluminum drop tube and the steel riser pipe, creating a lot of friction which must be overcome in order to remove the drop tube. Given the thin nature of the aluminum drop tube and the absence of any firm way to get a grip on the drop tube, mangling, if not complete destruction, of the drop tube often results.

Maine has required the annual inspection of overfill devices by removal for many years now. Experience has shown that a significant side effect of this inspection is that removal of drop tubes has become much easier. It seems that if drop tubes are removed on an annual basis, corrosion issues that interfere with the removal of the drop tube largely disappear.

Apparently, the main reason drop tubes are difficult to remove is that they are not removed on a regular basis. It remains to be seen whether removal on a three-year schedule is sufficient to keep corrosion at bay or whether the three-year interval is just enough time to make drop tube removal a cause of much cursing among UST tank technicians.

Removal of the drop tube will take more time than inspecting the device in place. This is particularly true where rules similar to California's "enhanced vapor recovery" are in place. One requirement of "enhanced vapor recovery" regulations is that spill-bucket drains must conduct liquid inside the drop tube rather than the traditional drainage path into the space between the fill riser and the drop tube.

This means that the top of the drop tube must be lowered to a point that is below the point where the outlet for the spill bucket drain enters the fill riser. Lowering the top of the drop tube creates the need for a "jack screw" assembly and a pipe nipple that is used to secure the drop tube in place. Removing these additional pieces of hardware will no doubt add a few minutes to the procedure to remove the drop tube. But these additional steps should not present any unusual obstacles, especially if the hardware is removed on a routine basis and does not have the opportunity to become seized in place.

What the Federal Rule Requires Drop-Tube Shutoff Devices to Do

Drop tube shutoff devices must shut off the flow of fuel when the fuel level is at 95 percent of the tank capacity or at a level such that the tank-top fittings are not wet with product.

Figure 3. *Movable floats on drop tube shutoff devices may not move. This may be due to corrosion (left photo) or human interference (right photo). Photos courtesy of Spruce Wheelock.*

Step One: Is the Drop-Tube Shutoff Device Working?

What the Manufacturers Say

Unless a drop-tube shutoff valve is specifically advertised as "testable," manufacturers' inspection procedures require removal of the valve and manual operation of the mechanism to verify that it works. Testable drop-tube shutoff valves either incorporate a cable that can be used to remotely operate the valve mechanism or a special tool that can be inserted in the drop tube to activate the valve mechanism.

Visual confirmation of the valve poppet moving into the drop tube when the mechanism is operated and then moving back to the side of the drop tube when released acts as confirmation that the valve is operational.

What RP 1200 Says

Although the current edition of RP 1200 was written well after testable versions of drop-tube shutoff devices were introduced to the marketplace, the RP 1200 Committee still presents a single option for testing these devices: removal, direct visual inspection, and manual operation of the mechanism. RP 1200 acknowledges that this is conservative, but this is what the Committee believes should be done.

Step Two: Is the Drop-Tube Shutoff Device Set to Operate at the Appropriate Level?

What the Manufacturers Say

If the device is removed, after measuring the tank diameter and determining the length of the fill riser, the distance from the top of the drop tube to a readily identifiable joint or other marker on the shutoff valve is calculated. The measurement should run from the top of the drop tube to the joint or marker on the shutoff device and be compared to the calculated number. Devices that can be tested in place follow a similar procedure, though measurements are based on the distance to the bottom of the tank, as the length of the fill riser is difficult to determine with the valve in place.

What RP 1200 Says

If the RP 1200 procedure is followed, the drop tube shutoff device is always removed from the tank for the inspection. RP 1200 also limits the inspection procedure to completely shutting off the flow at 95 percent of tank capacity. Most drop-tube shutoff devices operate in two stages. The first stage severely restricts the flow,

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with complete shutoff of the flow occurring at a higher fuel level in the tank. This allows for the draining of the delivery hose after the first stage has closed, but prevents the overfilling of the tank if the driver ignores the initial flow restriction stage.

Some manufacturer installation instructions result in the second stage operating at the 95 percent level of the tank, but others merely activate the first stage at 95 percent of tank capacity with complete flow shutoff occurring at about 98 or 99 percent of tank capacity. Following the RP 1200 inspection procedure requires that complete flow shutoff occur at the 95 percent level. This is contrary to some manufacturers' standard installation instructions, so alternative installation instructions would need to be used to determine the appropriate height of the shutoff valve in the tank. RP 1200 does not point out that this is the case, so the need to follow alternative installation instructions could be missed. See the first infrequently asked question below for further discussion of this issue.

■ Infrequently Asked Questions

Where Does the Device Actually Shut Off?

As discussed in the paragraphs above, most drop-tube shutoff devices are two-stage, and when installed according to standard manufacturers' instructions, complete flow shutoff may not occur until the fuel level is well over 95 percent. This meets the federal rule of shutting off the flow before the tank-top fittings are wet with fuel. However, some states' regulations do not include the "before tank-top fittings are wet with fuel" option and require complete shutoff to occur at 95 percent. In states that require shutoff at 95%, the owner must follow the manufacturer's modified instructions placing the valve lower in the tank to provide positive shutoff at 95—rather than 98—percent.

Likewise, RP 1200 also adopts this more conservative approach of completely shutting off the flow of fuel when the fuel level is no more than 95 percent of tank capacity. But RP 1200 neglects to mention that installers should NOT follow the "standard" installation instructions provided by the manufacturer of certain drop tube devices. Alternative installation instructions that provide for complete shutoff at 95 percent must be sought out and followed. These alternative instructions would also need to be followed when verifying the correct height of the drop-tube shutoff device during an inspection.

In states that enforce positive shutoff at 95 percent or adopt the RP 1200 inspection procedure it is likely that many shutoff devices will fail their first inspection for being set too high in the tank. In states that require positive shutoff at 95 percent, regulators will need to reach out to service companies to be sure they understand that the standard installation instructions are not to be followed for certain brands of shutoff valves.

Why Are Ball-Float Valves Such an Issue with Drop-Tube Shutoff Valves?

Most drop-tube shutoff valves rely on the flow of fuel down the drop tube to close the valve mechanism. All the float mechanism does is release a catch that holds the valve open. When the catch is released by the movement of the float, it is the flow of fuel that does the work of closing the valve. Remember that these valves re-open automatically, which means that there is a spring mechanism that is always trying to open the valve. If the fuel is flowing at less than a specified rate, there is not enough force to close the valve against the spring pressure that is working to keep the valve open. If working properly and if the tank top is tight, ball-float valves reduce the flow of fuel to a relatively small number of gallons per minute that is considerably less than the flow required to close the drop-tube shutoff valve. If a ball-float valve closes first, the drop tube shutoff valve is essentially bypassed and rendered useless.

At What Level Should the Ball-Float Valve Be Set If There Is a Drop-Tube Shutoff Valve Present?

Based on the previous question, it makes sense that if both a drop-tube shutoff valve and a ball float are present, the ball-float valve must be installed at a higher level in the tank than the drop-tube shutoff valve. This way the shutoff valve would operate first, when there would be full flow down the drop tube, and there would be sufficient fuel flow to close the shutoff valve. The ball float operation is not affected by the rate of fuel flow, so both devices could operate as they were designed to do.

According to RP 1200, if both a drop-tube shutoff valve and ball float are present, the ball float will fail the inspection if it is set to operate below the 95 percent level in the tank. This criterion for failing the inspection assumes the drop-tube shutoff device is set at 95 percent of tank capacity and so is intended to prevent the ball float from interfering with the operation of the drop-tube-shutoff device mentioned in the preceding paragraph..

But RP 1200 also states that the ball float will fail the inspection if flow restriction occurs when the tank is more than 90 percent full. These two criteria seem contradictory to me unless the RP 1200 pass/fail criterion only applies to the primary overfill device (drop tube), and the ball float is merely considered a secondary device. I'd say the safest thing to do here is to not have ball floats and drop-tube shutoff valves in the same tank.

What if There Is a Manway in the Tank?

Manways typically extend four to six inches above the top of the tank. Some manufacturer's installation instructions measure from the top of the tank to determine the location of the drop-tube shutoff valve and make no exception for manways. Without taking into consideration the height of the manway relative to the tank's top, the installer might accidentally place the valve too high in the tank.

A survey of a private company's tanks that had manways found that over a third of the valves were installed too high for this very reason. Not only did this make the shutoff level too high, but—depending on the orientation of the valve within the manway—the manway's edge (where the manway collar joins the tank shell) risked interfering with the operation of valves with floats that extend away from the drop tube.

If it is not possible to see whether a manway is present during an inspection, measurements to determine the correct location of the valve should be made with the tank bottom as a reference point rather than the tank top.

So, What's to Be Done?

It might be appropriate for USEPA to resolve some of the issues raised in this article in the technical compendium. Some of the questions that could be addressed include:

- If neither manufacturers' instructions nor an industry code of practice address an option described in the rule (e.g., the "one minute before overfill" overfill alarm option) can the option be used?
- What are the minimum loudness and brightness requirements for a overfill alarm?
- What should be the minimum duration of an overfill alarm?
- Should each tank and tank compartment have its own overfill alarm?
- Do the manufacturer's instructions for the "30-minute ball-float valve" provide sufficient assurance that this device is acceptable under all reasonably anticipated fuel level scenarios?
- Is the only way to disable a ball float to remove it?
- Is determining whether a manway is present part of the inspection procedure for ball floats and flapper valves?
- Do flapper valves have to be removed to be inspected / tested?

For more about overfill prevention inspection issues, go to the NEIWPCC 2018 national conference archives and view the presentations for "Flapper: An Overfill Prevention Story" at: *http://neiwpcc.org/our-programs/underground-storage-tanks/national-tanks-conference/2018-ntc-archive/* A webinar discussing overfill issues is also available on the NEIWPCC web site at: *http://neiwpcc.org/our-programs/underground-storage-tanks/ust-training-resources-inspection-leak-prevention/*webinar-archive-inspector-training/

Some Final Thoughts...

Phew!! I have spewed a lot of words to try to explain but one small paragraph in the 2015 amendments to the federal rule. And I didn't even get into what to do if the tank is significantly tilted, largely because I don't see an easy answer for where to set overfill equipment when the tank is not level. If you want more information on tank tilt and overfill prevention, see Kevin Henderson's presentation from the 2010 National Tanks Conference which is available on the NEIWPCC website at the National Tank Conference archives page: *http://click.neiwpcc.org/tanks2010/presentations.asp*).

There is no doubt that inspections of overfill equipment to verify that they are properly installed and operating are a good thing. But conducting the first round of inspections is going to raise some thorny issues, in part, because this equipment has been neglected for so long

■ continued on page 22

Update on Sump Testing Methods

by Ed Kubinsky and Marcel Moreau

LUSTLine #83, published in December 2017, devoted a lot of space to the topic of the hydrostatic testing of sumps, which is now a requirement of the federal UST rule. If you spent any time reviewing the various articles in that issue of *LUSTLine*, you would likely have concluded that hydrostatic testing of sumps was a nettlesome method of establishing the liquid tightness of sumps. Testing the sumps at high level (water level during the test above all the penetrations and joints), while providing a reasonably thorough assessment of the integrity of the sump, opened a can of worms regarding the nature of the voluminous test water and how to transport and dispose of said water. Low-level testing (water level during the test of only a few inches) helped ameliorate the water issues, but resulted in a very incomplete assessment of the integrity of the sump.

Surely there must be a better mousetrap. And so, in true entrepreneurial fashion, various folks have come up with alternative sump-testing methods that evaluate the entire sump but do not entail the handling and disposal of many hundreds of gallons of water. The goal of this article is to provide a quick overview of two alternative sump-testing methods. Both methods:

- can be used to test spill buckets, as well as tank-top sumps and under-dispenser sumps
- have been third-party tested by Ken Wilcox Associates and have passed muster with the National Workgroup on Leak Detection Evaluations

■ continued on page 18

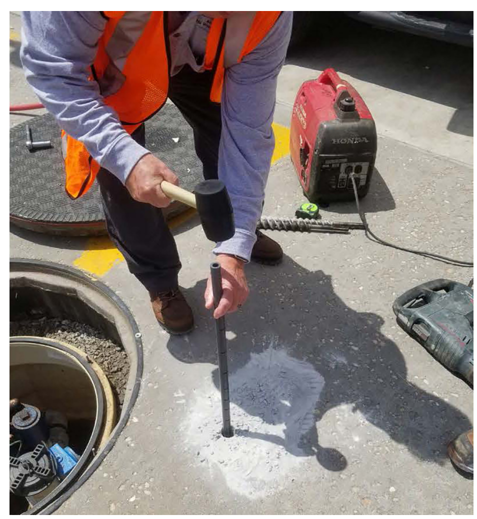

Figure 1. *In the Dri-Sump method of sump testing, Vapor Stimulating Tubes (VSTs) are first driven into holes drilled in close proximity to the sump(s) to be tested. During the test, a vacuum is applied to these tubes. If any holes are present in the sump, the aerosol is drawn through the hole, into the backfill, into the VST, and then into a box where a laser beam reveals the presence of the aerosol.*

■ Update on Sump Testing Methods *from page 17*

- are commercially available today, although they may not be available from a nearby source in all parts of the country
- train and certify technicians to conduct their tests.

This article provides a brief description of how each of these methods works and some tables listing what we see as the pros and cons of each method. The mention of trade names in this article is so that the reader can know which methods we are discussing. The use of trade names in no way implies endorsement by USEPA, NEIWPCC, or the authors. In the interests of full disclosure, Crompco, Ed Kubinsky's employer, is planning to add the Dri-Sump testing method to its arsenal of testing methodologies.

Dri-Sump, Developed by AC'CENT Environmental

The Dri-Sump approach is a form of tracer test in that a substance is introduced into the sump and then the environment immediately outside the sump is monitored for the presence of this substance. The tracer in this case is a heavier-than-air aerosol that looks a lot like the special effects fog that you may have seen in theaters or other entertainment venues. The composition of the aerosol is proprietary, but AC'CENT Environmental has told the National Work Group for Leak Detection Evaluation (NWGLDE) that it is non-toxic and environmentally friendly.

To prepare for the test, small-diameter vapor stimulator tubes (VSTs) are driven vertically into the backfill within 8 inches of the sump or spill bucket to be tested. One VST is sufficient to test a spill bucket, two would be installed to test a typical STP or under-dispenser sump. VSTs for spill buckets are 18 inches long, while those for STP and dispenser sumps are required to be 36 inches. VSTs are essentially vapor monitoring wells and are permanently installed at a site by drilling a hole the size of a quarter through the concrete and driving the VST through the backfill with a hammer.

A communication test to ensure the VSTs are properly installed and the backfill is sufficiently porous can be performed by pulling a vacuum through one VST and watching a manometer on an adjacent VST to observe a decrease in pressure. According to the third-party certification, the Dri-Sump test method can be used in pea gravel, sand, or clay/silt backfill.

Figure 2. *In the Dri-Sump method of sump testing, the sump is filled with a cloud of dense aerosol.*

The spill bucket or sump being tested must be clean and dry. The test is conducted with the lid of the spill bucket or sump removed, although under windy conditions the lid may be left loosely in place to help keep the aerosol in the sump.

During the test, a vacuum pump is connected to the VST(s) and the sump being tested is filled with the aerosol. The vacuum pump pulling air through the VSTs generates a small vacuum in the backfill outside the sump. If there are any holes in the sump wall or any leaks in any of the penetration fittings, air and aerosol from inside the sump will be pulled into the backfill outside the sump and into the VSTs. The air pulled from the VSTs passes through an empty black box (about 24 x 18 x 8 inches) with two clear plastic viewing ports. The beam from a green laser pointer is directed through one of the viewing ports, and the tester observes the laser beam through the other viewing port. In the absence of any aerosol, the laser beam shows up as a green dot on the inside surface of the black box. If any aerosol is present in the black box, the laser beam shows up as a line (think *Star Wars* light saber) as the laser beam illuminates the particles of the aerosol. If the tester sees a green beam rather than a green dot inside the black box, the sump fails the test.

The first time a site is tested, it is likely to take an hour or two to install the required VSTs. But once the VSTs are installed, tests can be done very efficiently as all that is required is to hook up the vacuum pump to the appropriate VST(s) and fill the sump with aerosol. Because the VSTs are so close to the sump being tested, and because there is a vacuum present to move the aerosol though the backfill, the time to complete a test once the equipment is set up is only a few minutes.

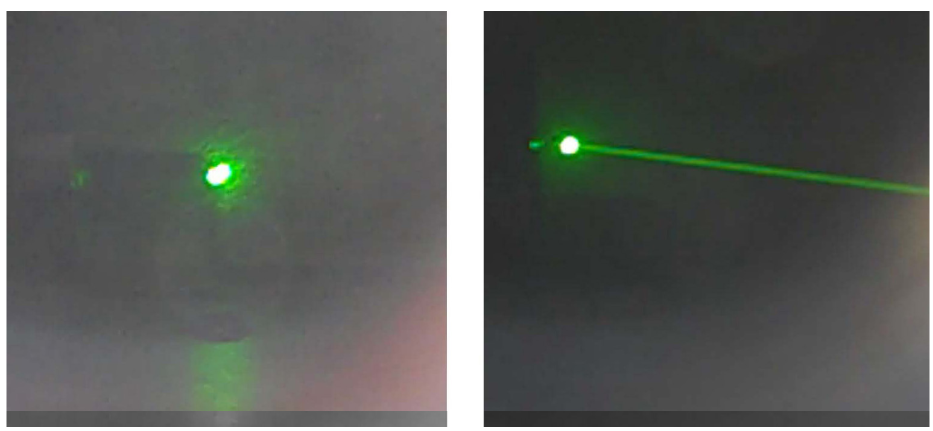

Figure 3. *The view inside the Dri-Sump black box. A vacuum draws air from the VSTs into the black box. A green laser pointer beam is directed through a viewing port into the box. In the absence of any aerosol, the laser shows up as a dot on the wall inside of the box (left photo). When aerosol is present, the laser shows up as a beam (right photo).*

The Dri-Sump method does not identify the location of the leak, but we understand that the developer of the method is working on a way to do this.

Differential Pressure Leak Test (DPleak™) Developed by Leak Detection Technologies

As a company, Leak Detection Technologies provides leak detection in many different areas and has several different testing methodologies listed on the NWGLDE website. The DPleak sump testing method is like the soap test that is typically used to check the integrity of an underground tank after it arrives at a site but before it is placed in the ground. In the case of tanks, the inside of the tank is pressurized slightly and the outside of the tank is sprayed with a soap solution. Any leaks in the tank show up as soap bubbles on the outside surface of the tank.

The DPleak approach to sump testing essentially turns this process inside out. A vacuum is applied to the inside of the sump and a solution that creates soap bubbles is sprayed on the inside surface and all the penetrations in the sump. If bubbles appear anywhere inside the sump, a leak is present. If groundwater is present outside the sump and the inside of the sump is clean and empty, leaks can also be identified by the ingress of water. The DPleak method is the only sump test that identifies the actual location of the leak.

While simple in concept, this method gets a little more complicated when STP sumps are being tested. To enable a vacuum to be maintained in the sump, a clear plexiglass disc is installed to replace the normal STP sump lid. Built into the lid are two arms-length "gloves" that allow the technician, while lying on the ground on his stomach, to reach into the sump (see photo of Ed trying this out). The lid also incorporates a connection to a vacuum pump to pull a vacuum inside the sump. It is important to note that this is not a vacuum test where the vacuum is established in the sump and then the vacuum is monitored to see if it degrades. The vacuum pump in this test runs continuously during the test and is adjusted to maintain a specified level of vacuum in the sump.

The technician has a small video camera in one hand and a sprayer for the soap solution in the other hand. An aboveground video screen, which can be a laptop computer or TV monitor, is connected to the video camera in the tester's hand inside the sump and is observed by the tester. The tester then systematically sprays the entire surface of the sump and each penetration fitting with the soap solution and then points the camera at the area he has just soaped to see if bubbles appear on the video screen in front of him. The presence of bubbles (or the ingress of water if groundwater is present outside the sump) indicates a leak.

Figure 4. *In the Leak Detection Technologies method of sump testing, a temporary lid with attached arms-length gloves is installed over an STP sump. The gloves allow a technician to work inside the sump while a vacuum is maintained in the sump.*

Figure 5. *During the Leak Detection Technologies test, a vacuum is maintained in the sump while a technician sprays a soap solution on the sump wall and sump fittings with one hand and maneuvers a video camera in the other hand. The video image is transmitted to a screen that the technician (that's Ed in this photo) watches closely to see if any bubbles appear.*

The method gets a little trickier with dispensers, because you want to avoid the time, expense, and inconvenience of removing the dispenser to conduct the test. So to establish a vacuum, a large "bag" is slipped over the dispenser and duct taped to the surface of the dispenser island. Built into a side of the "bag" is a plexiglass section with two arm's length gloves, just as are used to test STP sumps. The technician must then reach into the sump and maneuver the spray nozzle and the camera so that the entire inside surface of the under-dispenser sump and all penetration fittings are evaluated.

A video recording is made of the DPleak test, and the video is reviewed by Leak Detection Technologies' personnel at headquarters who make the final determination as to whether the sump or spill bucket has passed or failed the test.

Are These Methods Included in RP 1200?

Petroleum Equipment Institute RP 1200, *Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection, and Secondary Containment Equipment at UST Facilities* is cited in the federal rule as a document that contains acceptable sump- and spill-bucket-testing methodologies. PEI's RP 1200 Committee has discussed these new methods of testing sumps and spill buckets, but has decided not to include them in the document at this time. As a result, UST regulatory agencies will need to approve these methods on an individual basis.

■ *continued on page 20*

■ Update on Sump Testing Methods *from page 19*

As a side note, RP 1200 is currently under revision. While the present edition of RP 1200 only includes a high-water level method for sump testing, future editions of RP 1200 will also include a methodology for testing STP and under-dispenser sumps at low-water levels.

Are Better Mousetraps Yet to Come?

Never underestimate American ingenuity. As of right now, these are the only two additional methods of sump testing that we are aware of that evaluate the entire sump, without the handling and disposing of many hundreds of gallons of water. But who knows what the future holds? ■

Ed Kubinski is the Director of Regulatory Affairs, Training, and Certification at Crompco, LLC. He leads Crompco's compliance department that manages regulatory compliance equipment testing and inspections for several thousand UST sites.

*Marcel Moreau is a nationally recognized petroleum storage specialist whose column, **Tank-nically Speaking**, is a regular feature of LUSTLine.*

Table 1. Comparison of National Work Group for Leak Detection Evaluation Third-Party Evaluation Summaries

	Ac'cent Environmental Dri-Sump	Leak Detection Technologies Differential Pressure Leak Test
Certification	Leak rate of 0.1 gph with PD = 100% and PFA = 0%	Leak Rate of 0.1 gph with PD = 100%, PFA = 0% Leak rate of 0.005 gph with PD = 96% and PFA = 0%
Specification	Sump must be free of debris and measurable liquid	Containment must be clean and empty
Waiting Time	No waiting time	No waiting time
Test Period	Minimum of one minute	For 0.1 gph: less than 1 hour for sump test, 20 sec/ft^2 of sump surface area
Water Table	Must be below the sump being tested; water level determined using vapor stimulator tubes (VST) installed as part of the test.	Must be determined to conduct the test; create monitoring well if none present
Leak Indicator	Leak is determined by change in specialized laser light beam from a dot to a line	Leak is determined by air ingress forming bubbles, or liquid ingress if water table is higher than the bottom of the sump
VST Placement	VSTs must be placed at a maximum distance of 8 inches (+/- 1 inch) from the sump wall	N/A

DRI-SUMP

Pros	Cons
No liquid to handle or dispose of	Risk of damaging buried piping when installing VSTs
Tests the entire sump	Does not identify the location of the leak, though the developer of the test is working on a way to do this
Repeat tests can be quickly conducted because VSTs are permanently installed	Some facility owners don't like the fact that holes are drilled in the concrete to install the VSTs
Test results are determined immediately by the on-site tester.	There is no record of the actual test, just the pass/fail result provided by the tester.
	Not applicable if the water table is above the bottom of the sump being tested.

LEAK DETECTION TECHNOLOGIES

Pros	Cons
Very small amount of liquid (the test solution applied to fittings and the sump wall) to handle and dispose of	Spraying all fittings and sump surfaces and viewing results using a camera connected to a video screen can challenge the test technician's patience in a sump crowded with STPs, piping, sensors, and electrical conduits
Tests the entire sump	Technician may need to work in uncomfortable position(s), especially when viewing under-dispenser sumps
Identifies the location of the leak	Equipment setup for each STP or dispenser sump to be tested is about an hour.
There is a video record of the test in case any questions arise at a later time.	Final results are not immediately available because the video must be reviewed by Leak Detection Technologies personnel at headquarters.
Can be used where the water table is above the bottom of the sump being tested.	

Field Notes

from Rick Long, Executive Vice President, Petroleum Equipment Institute (PEI)

Brought to You by the Numbers 4, 1, and (E)15s

Professionals in the petroleum equipment industry deal with lots of numbers—job costs and estimates, tank-monitor readings, leak detection reports, equipment models…and not to mention all sorts of numbers on all sorts of tax, regulatory, and customer forms.

This edition of "Field Notes" is brought to you by what we think are three of the most important numbers that have emerged during the last few months: 4, 1, and (E)15.

4 Recommended Practice Revisions

Since the March 2019 *LUSTLine*, PEI committees have revised four of the association's recommended practices. Here's a summary of each document and its most recent revisions.

- ***Recommended Practices for Installation of Aboveground Storage Systems for Motor Vehicle Fueling* (PEI/RP200-18)**. This longstanding document covers all aspects of proper aboveground storage tank (AST) installation, including: site planning, foundations, support; dikes, vaults; tanks; pumps, valves, gauges, vents, piping, fittings, corrosion protection, environmental protection, testing, and inspection.

  The 2019 edition of RP200:

  - addresses new National Fire Protection Association (NFPA) requirements for aboveground tank labeling and identification
  - amends a section on vertical tanks to meet recent NFPA requirements
  - updates single- and double-walled component testing procedures for horizontal tanks
  - adds references to two new USEPA documents on diesel storage tank corrosion.

- ***Recommended Practices for Installation and Testing of Vapor Recovery Systems at Vehicle Fueling Sites* (PEI/RP300-19)** provides concise instructions for installation and testing of Stage I and Stage II vapor recovery equipment, as well as for decommissioning Stage II piping. The 2019 revision adds testing of pressure/vacuum (PV) vents to the decommissioning process and updates essential background references.

- ***Recommended Practices for Overfill Prevention for Shop-Fabricated Aboveground Tanks* (PEI/RP600-19)** lays out proper procedures for reducing AST overfill incidents. The universal procedures in the document are particularly important because AST facilities are notorious for employing widely varying configurations of fuel-transfer pumps, pipes, valves, and controls. The 2019 edition of RP600 includes important updates to references and background material.

- ***Recommended Practices for Inspection and Maintenance of Motor-Fuel Dispensing Equipment* (PEI/RP500)** provides preventative and incident-response procedures for dispensers to guard against equipment failure, reduce fire hazards, promote safety, and minimize environmental problems. The newest edition of the document:

  - adds a section to clarify the responsibilities of Class A, B, and C Operators
  - addresses electronic storage of inspection, maintenance, and repair records
  - updates the "Training Documentation" section to conform with federal requirements
  - includes procedures for identifying skimmers and unauthorized card readers during daily inspections
  - incorporates the decommissioning of Stage II vapor-recovery equipment.

1 Big Change on the Horizon

The 2015 federal underground storage tank (UST) regulations require vacuum, pressure, or hydrostatic testing of containment sumps used for interstitial monitoring at least once every three years to ensure the sumps are liquid-tight. The hydrostatic testing procedure in PEI's *Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection, and Secondary Containment Equipment at UST Facilities* (PEI/RP1200) is recognized in the regulation as a sufficient method to meet this requirement.

Under the RP1200 method, the owner or operator fills the sump with water to a depth of at least 4 inches above the sump's highest penetration or sidewall seam. The sump passes the test if the water level drops by less than 1/8 (0.125) inch after 1 hour.

In November 2017, USEPA determined that a low-level-liquid sump test, when combined with other safeguards, also could be sufficient to meet its sump testing requirements. After months of work, the PEI committee respon-

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Field Notes continued from page 25

sible for RP1200 released draft procedures for low-level- liquid sump tests in May 2019. The draft procedures would require:

- A liquid sensor configured to shut down the submersible turbine pump (STP) upon activation of the sensor
- Stand-alone sensors that would shut down the appropriate dispensing device, or
- Mechanical float devices to shut down flow at the shear valve.

During the 30-day public comment period, regulators, marketers, and equipment professionals submitted nearly 100 comments and suggestions. As I write this article, the committee is reviewing these comments to determine whether the draft procedures could be improved and, if so, how. The final RP1200 revisions will be released late summer or early fall.

15 Is E15 Coming Soon to a Retailer Near You?

On May 30, USEPA granted E15 a 1-pound summertime Reid Vapor Pressure (RVP) waiver. The move makes the year-round, nationwide sale of E15 legal. However, other legal, market, and compatibility questions leave the future of E15 anything but clear.

Litigation. Within hours after the E15 rule was published in the *Federal Register*, the American Fuel & Petrochemical Manufacturers (AFPM) filed suit in federal court to block the waiver. AFPM President and CEO Chet Thompson explained that in AFPM's view, the "plain language of the Clean Air Act does not authorize an RVP waiver expansion beyond E10. Nothing has changed—a waiver for E15 is unlawful, plain and simple."

Ethanol advocates Growth Energy and the Renewable Fuels Association quickly jumped in to support the USEPA rule. "[T]he law is on our side," said Emily Skor, CEO of Growth Energy. "We know—and the EPA has said—the agency has clear authority to implement the law through appropriate regulations. A move toward cleaner fuels is exactly what Congress intended under the Clean Air Act."

Retailer Response. The National Association of Convenience Stores (NACS), the Society of Independent Gasoline Marketers of America (SIGMA), and NATSO, the national association representing truck stops and travel plazas, gave lukewarm assent to the USEPA action, affirming in a joint statement that they "do not object" to the new rule.

Individual fuel marketer response also was muted. The biggest announcement came from Casey's General Stores, which said on June 3, it would add E15 at more than 60 stores this summer, as part of a previously announced plan to sell E15 at up to 500 Casey's locations over time.

Compatibility. Although the year-round sale of E15 is now legal, individual fuel marketers must meet a number of requirements before adding the blend to their fuel mix. The most challenging requirement—especially for an existing facility—is proving the compatibility of the site's fueling equipment with the fuel.

On June 24, USEPA issued a compliance advisory reminding owners and operators of their compatibility requirements. As detailed in the advisory, marketers wishing to sell fuel containing more than 10% ethanol (or 20% biodiesel) must demonstrate compatibility of the following UST system components:

- the tank
- piping carrying product from the tank
- containment sumps
- pumping equipment, including the submersible pump or suction pump
- release-detection equipment, including automatic tank gauge (ATG) probes, sump sensors, and line-leak detectors
- spill-ssprevention equipment, such as spill buckets
- overfill equipment, including ball-float valves or flapper valves.

As an industry service, PEI hosts a UST Component Compatibility Library with a continually updated list of manufacturer letters affirming the compatibility of specific equipment with the higher-level ethanol and biodiesel blends.

Our take: major retailers will continue to introduce E15 at some new sites and other strategic locations in the coming year. But the higher-level blend won't make major inroads into the nation's vehicle fuel supply in the near future. ■

■ Inspecting Overfill Protection Equipment from page 17

and in part, because of the incompatibility of ball floats and drop-tube shutoff valves. There is likely to be much cursing among technicians trying to remove equipment that has been undisturbed for many years, and much gnashing of teeth among tank owners faced with expensive work to resolve some of the issues described above.

But as far as the tank world and delivery drivers are concerned, life will be much less complicated when all ball floats are removed and we deal with a tank universe that has only drop-tube shutoff valves and overfill alarms installed.

Did I miss anything? If you have additional questions or different answers, write to me at marcel.moreau@juno.com ■

Footnotes

1. "OPW Installation and Maintenance Instructions, 53VM / 30 MV and 233 Series Ball Float / Extractor Assemblies," OPW Fueling Components Inc., Copyright 2002.
2. "OPW Installation and Maintenance Instructions, 53VM / 30 MV and 233 Series Ball Float / Extractor Assemblies," OPW Fueling Components Inc., Copyright 2002.
3. *http://www.opwglobal.com/products/us/retail-fueling-products/below-ground-products/underground-storage-tank-equipment/overfill-prevention-valves/53vml-30mv-ball-float-vent-valves*

An Approach to Closing Certain LUST Sites with Contamination in Place

John T. Wilson

Groundwater flows rapidly through sand and gravel aquifers and can carry a plume of contamination a substantial distance in a short period of time. There is a significant risk that a fuel spill will impact a receptor well. Fortunately, these sites are relatively easy to clean up. In contrast, groundwater flows very slowly through silt and clay. Most often, this plume of contamination does not extend a significant distance from the area with residual hydrocarbons. The risk of impacting a receptor well is low, but these sites are difficult and expensive to clean up. Despite heroic efforts, some of the wells at these sites never reach the standards for drinking water.

The U.S. Environmental Protection Agency (USEPA) risk management paradigm is to destroy the hazard or prevent exposure. States implementing the UST program often don't use the flexibility in the USEPA policy. They put too much attention on destroying the hazard without examining ways to evaluate exposure. They try to manage the contaminants instead of managing the aquifer as a water supply. Even though some monitoring wells at a site are still contaminated, it may be possible that the goal has been attained, that groundwater moving away from the site is clean, and that the aquifer has been restored as a source of drinking water.

Fuel Hydrocarbons and the Water Table

Many of our cities are built in the floodplains of rivers. In many floodplain landscapes, the surface soil and sediment are an overburden of silt and clay. The sands and gravels that can move groundwater lie below the layer of silts and clays. Often the water table is in the layer of silt and clay. When fuel hydrocarbons are released, they are wicked up by the capillary fringe and may be confined to the silt and clay.

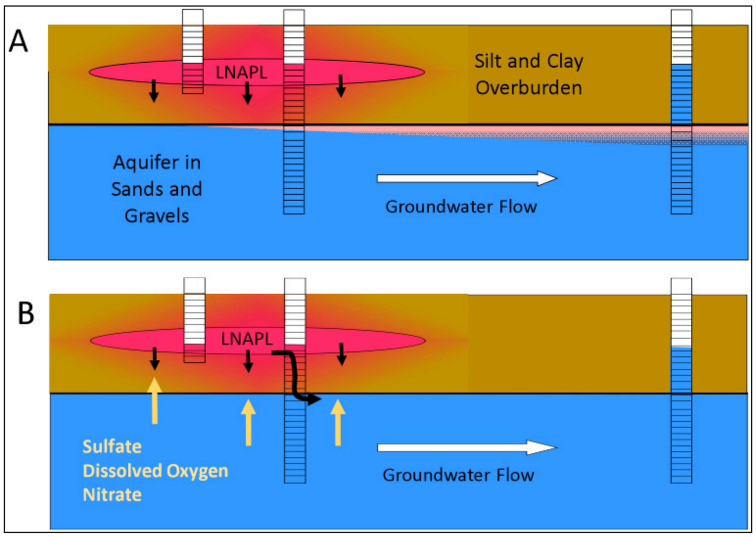

Figure 1. *A conceptual model of the interaction of residual petroleum hydrocarbons in a clay and silt overburden with flowing groundwater in the aquifer below.*

How does contamination in Light Non-Aqueous-Phase Liquid (LNAPL) in a layer of silt or clay interact with flowing groundwater in an aquifer below the silt or clay layer? This situation is presented diagrammatically in Panel A of Figure 1. The water table in the clay and silt moves up and down with changes in the pressure head in the aquifer. As a result, water is either moving from the aquifer up into the clay and silt or draining downward from the clay and silt to the aquifer. Contamination can be transferred to the aquifer by groundwater flow when the water table is falling. Contamination can also be transferred to the aquifer by diffusion through the groundwater in the clay and silt. In either case, the contamination enters the aquifer under the footprint of the lens of residual LNAPL hydrocarbons. There is little or no lateral movement of contamination in the clay and silt.

A monitoring well installed across the residual LNAPL hydrocarbons can produce water with high concentrations of contaminants. The high concentrations are not an accurate representation of the concentrations that would cross from the clay and silt and impact the sand and gravel aquifer through diffusion. Since the downward transfer of contamination by flow of groundwater or diffusion in groundwater is slow, relatively little contamination escapes the LNAPL to enter the aquifer. As the relatively small mass of contamination enters the aquifer, it is diluted in the flow of groundwater in the aquifer (Cho et al., 2000) to produce lower concentrations in any monitoring well installed downgradient of the residual LNAPL.

If a monitoring well is screened across silt and clay containing LNAPL as well as the sand and gravel of the underlying aquifer, the water produced from the well is a composite of water produced from both units. If the well has been thoroughly purged before sampling, the well water will be largely drawn from the sand and gravel aquifer, and the concentrations of petroleum hydrocarbons will be relatively low (Panel A). If the well is not purged, petroleum hydrocarbons will accumulate in the well water because a portion of the well water is in close contact with the LNAPL. When the water table falls, the wells acts a manmade preferential pathway to transfer hydrocarbons to the aquifer (Panel B of Figure 1).

Hydrocarbons in groundwater in the clay and silt layer can be degraded by natural bacteria that use oxygen, sulfate, or nitrate to support metabolism of the contaminants. If these chemicals are present in the water in the aquifer, this will allow the bacteria to degrade the hydrocarbons as they enter the aquifer (Cho et al., 2000). If this is the case, the hydrocarbons might never be detected in monitoring wells down gradient of the NAPL hydrocarbons (Panel B of Figure 1).

■ continued on page 24

■ **Closing LUST Sites with Contamination** *from page 23*

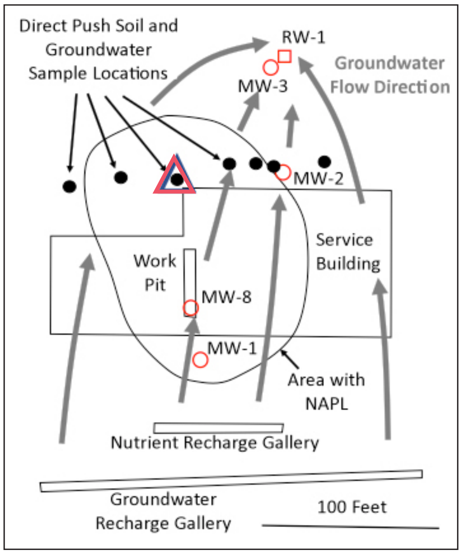

Figure 2. *Layout of active bioremediation of hydrocarbon contamination at the Public Services Site.*

A Public Services Site in Denver

The situation is illustrated in a case study done at the Public Services Site, a RCRA site in Denver, Colorado (Wilson and Kampbell, 1993). The site was a building used to service trucks. Gasoline, motor oil, and transmission fluid were disposed to a dry well under the floor of the garage. The dry well contaminated the first aquifer below the water table. Aerobic in situ bioremediation was used to clean up the spill.

Figure 2 depicts the layout of remedial action. A recharge gallery was used to sweep a solution of nutrients and hydrogen peroxide under the building. A second groundwater recharge galley was used to improve the sweep. The injected water was recovered at RW-1 and recirculated to the injection galleries.

Table 1 compares the concentration of benzene and BTEX in the monitoring wells before, during, and after active remediation. There were substantial reductions in concentrations; however, the concentrations of benzene in well MW-8 did not reach the drinking water standard of 5 μg/L. The wells downgradient of MW-8 did reach the standard.

To evaluate whether the site was ready to close, Wilson and Kampbell (1993) did a performance evaluation.

Well	Benzene			BTEX		
	Before	During	After	Before	During	After
	μg/L					
MW-1	220	<1	<1	2,030	164	<6
MW-8	180	130	16	1,800	331	34
MW-2A	?	11	0.8	?	1,200	13
MW-3	11	5	2	1,200	820	46
RW-1	<1	2	<1	<1	2	<1

Table 1. *Reductions in concentrations of benzene and BTEX compounds during aerobic bioremediation at the Public Services Site in Denver, CO.*

Depth	Hydraulic Conductivity	Benzene	BTEXTMB*	Oxygen	Nitrate Nitrogen	Sulfate
Feet	Feet/Day	μg/L	μg/L	mg/L	mg/L	mg/L
18 to 20	0.39	11.3	636	Could not measure	Could not measure	Could not measure
20 to 22	15.8	2.8	64	0.6	8.9	226
22 to 24	186	1.0	25	0.3	7.1	232
24 to 26	186	<1	23	0.5	4.9	239
25 to 28	0.66	<1	24	1.4	4.8	215
28 to 30	0.003	<1	92	Could not measure	Could not measure	Could not measure

Table 2. *Vertical distribution of hydraulic conductivity, selected petroleum hydrocarbons, and electron acceptors at the most contaminated location sampled by USEPA.*

They collected a series of continuous core samples extending from the water table through to the bottom of the first aquifer at the site, a total depth of 30 feet below the ground surface. The core samples were extracted and analyzed for total petroleum hydrocarbons (TPH). The black dots in Figure 2 denote locations of the core samples. At the same locations, Geoprobe® tools were used to collect groundwater samples from a continuous vertical interval. Also used was a method described by Cho et al. (2000) that uses Geoprobe® tools to perform a hydraulic conductivity test in the depth intervals that supplied the water samples.

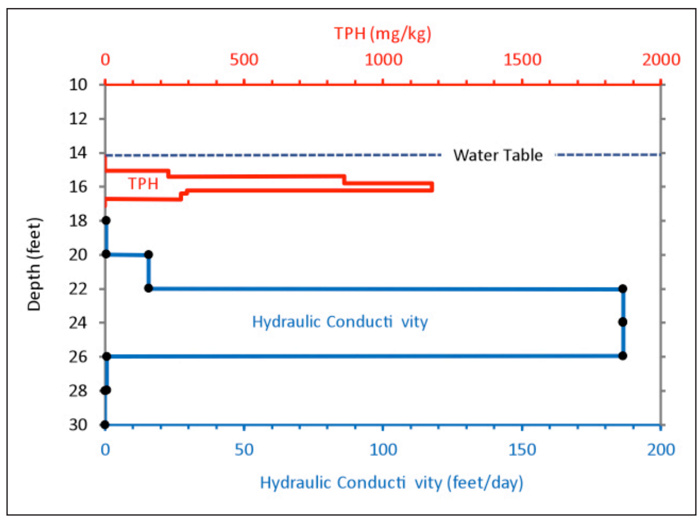

Figure 3. *Vertical distribution of TPH and Hydraulic Conductivity at the location with the highest concentration of TPH.*

The most contaminated location sampled by Wilson and Kampbell (1993) is identified by a red triangle in Figure 2. Data from this location is provided in Figure 3 and Table 2. A considerable amount of residual LNAPL hydrocarbons (TPH) remained at the site after active remediation. However, detectable concentrations were confined to a narrow interval between depths of 15 and 17 feet in the clay and silt overburden.

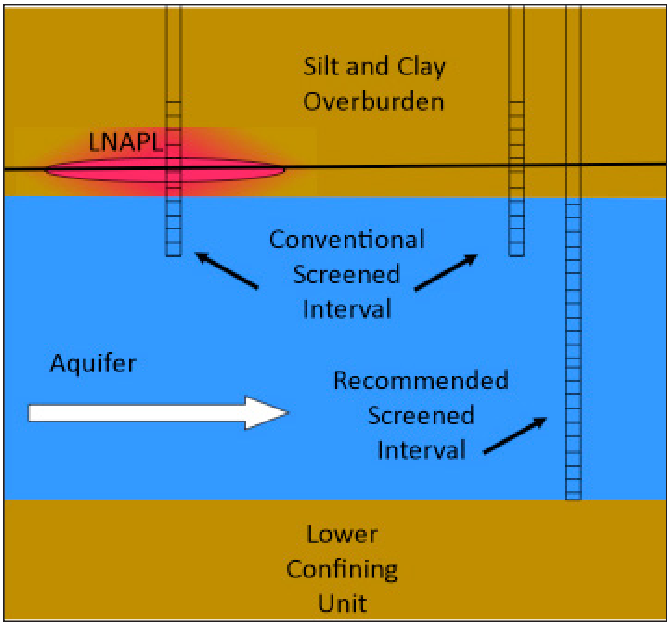

Figure 4. *A comparison between the conventional practice of screening monitoring wells at a UST site and a monitoring well that is screened to evaluate whether the aquifer can be used to supply drinking water.*

The shallowest aquifer at the site, as measured by hydraulic conductivity, did not start until a depth of 20 feet, and extended to a depth of 26 feet.

The wide contrasts in hydraulic conductivity are a bit hard to read from Figure 3. Data on hydraulic conductivity, and the concentrations of benzene and BTEX compounds are provided in Table 2. Notice that the highest concentrations of benzene and BTEX are from the depth interval immediately below the LNAPL. The geologic material in this interval has low hydraulic conductivity and would not function as an aquifer. As depth increases, the hydraulic conductivity increases by almost five hundred-fold, while the concentrations of the contaminants decrease by at least ten-fold.

The flow velocity of groundwater is proportional to the hydraulic conductivity. The average concentration of contaminants that would be produced by a well can be estimated using a flow-weighted average of the concentrations of contaminants in the various discrete depth intervals that are sampled by the well (Einarson et al., 2017). The flow-weighted benzene concentrations in Table 2 were calculated by multiplying the concentration in each discrete vertical depth interval by the hydraulic conductivity of that depth interval. If benzene was not detected, the detection limit was used to calculate the flow-weighted benzene concentration. Then the average of the flow-weighted concentrations was divided by the average of the hydraulic conductivities for the depth intervals.

The flow-weighted average for benzene in water that would be collected in a monitoring well that is screened across the shallowest aquifer would be 1.08 µg/L. This estimate is entirely consistent with the measured concentrations of benzene in wells MW-2A, MW-3, and RW-1 at the Public Services Site after remediation (Table 1).

Notice in Table 2 that the water in the aquifer had low but useful concentrations of dissolved oxygen and high concentrations of nitrate and sulfate. There were adequate electron acceptors in the groundwater to allow the bacteria to degrade the low concentrations of hydrocarbons that were transferred from the LNAPL to the flowing groundwater in the aquifer.

The contamination left in place did not prevent the wells from attaining the cleanup standard.

The Take-Home Message?

In certain settings, such as those described above, it is not necessary to clean up the water in all the monitoring wells to drinking water standards in order to be protective of the aquifer as a source of drinking water. If groundwater that leaves the spill site meets drinking water standards, then the down-gradient aquifer is restored as a drinking water source.

What are the primary recommendations? Use the geophysical and site characterization tools to install monitoring wells that sample the aquifer in the same way a water production well would sample the aquifer. Do something in addition to a five-foot screen set across the water table. Consider the nature of the geological material being sampled, and screen the monitoring wells across the geological structures that function as the shallowest aquifer (See Figure 4).

Determine the relationship between residual hydrocarbons and hydraulic conductivity at your site and use this information to select the screened interval for your monitoring wells. In a previous edition of *LUSTLine*, Dyment and Kady (2018) discussed the power of new high-resolution site-characterization tools to improve the conceptual model of a site and identify practical and effective remedies for groundwater contamination. The approach of Cho et al. (2000) to determine vertical profiles in hydraulic conductivity has been superseded by improved tools.

Figure 5 provides example data from a site that was characterized with a direct-push tool that simultaneously measured electrical conductivity and a surrogate for hydraulic

■ *continued on page 27*

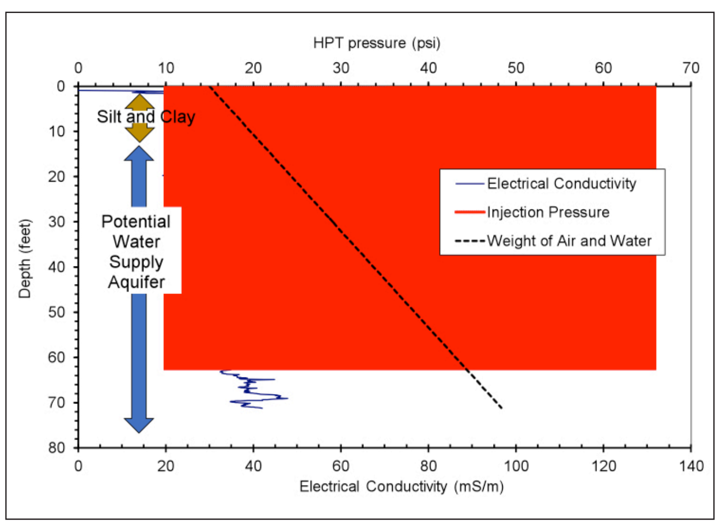

Figure 5. *An example of the data provided by modern tools to distinguish clay and silt from sand and gravel and determine the vertical distribution of hydraulic conductivity. Courtesy Wes McCall, Geoprobe Systems®.*

The RISK Factor | by Patrick Rounds

Patrick Rounds is president of Petroleum Marketers Management Insurance Company (PMMIC), an Iowa-based insurance company that provides insurance for owners of petroleum USTs. The company was created by and is owned by UST owners. Pat can be reached at: PJR @pmmic.com

The RISK of Bad Data

Decisions are made based on data.

In the UST world, we had very limited data when Congress decided to regulate tanks in 1984. The USEPA implemented regulations in 1988 that addressed the problems believed to be the most common and which caused the most severe UST releases. At the time they had very limited data. They didn't have comprehensive data on the source and cause of releases. The regulations addressed overfill-prevention, spill protection, leak detection, and corrosion protection among other issues. By most accounts, the 1988 regulations have been very successful, but better data is still needed.

For the Record

Section 1526 of the Energy Policy Act of 2005 required states receiving federal funds for UST oversight to update at least annually, and make available to the public a record of regulated USTs. The public record was to include not only the number, sources, and causes of UST releases, but the record of compliance by underground storage tanks in the state and data on equipment failures. Congress mandated better data.

OUST collects data from states and territories and publishes UST Performance Measures twice each year. The data includes the number of confirmed releases, number of active tanks, and various compliance data. The Performance Measures do not include data on cause and source of release. For FY 2018, USEPA reported 5,654 confirmed releases. The report indicated there were 550,379 tanks at approximately 199,000 sites.

Here at PMMIC Insurance, in order to complete a simple cause of release study, we had to obtain information on releases from every state. States are required to provide a public record that addresses the number, source, and cause of reported releases each year. We found current data for 48 states on state websites. One state had old data and another only provides cumulative data of all releases confirmed (no annual data).

We performed a very simple cause of release study by reviewing the UST releases that were documented in FY 2018 as reported by each state. The data from 48 states documented 5,707 confirmed releases, slightly greater than the USEPA data even with two states and all territory data missing. Based on state release data, and USEPA site and facility estimates, the industry experienced approximately one release out of every 100 tanks which is approximately three releases for every 100 facilities.

State-Reported Data

Release Source		Release Cause	
Unknown	29%	Unknown	55%
Tanks	28%	Physical Damage	15%
Piping	11%	Corrosion	08%
Dispensers	11%	Spills	04%
Turbine Sumps	02%	Installation problems	01%
Delivery Overfills	01%	Delivery Overfills	01%

To validate the state-reported data, we compared the state data with our own source and cause of release data from insured UST systems since 1989. For our internal data, we utilize professional inspectors to verify system configurations and to determine compliance with state and federal regulations and our underwriting standards on an annual basis. We investigate every release. Our data indicates that today, tanks are the source for less than 5% of all releases. Corrosion is the cause for less than 5% of our releases. Overfills are the source for 1% of releases. This leaves dispensers as the source of more than 90% of all leaks—and possibly the majority of releases.

Comparing our data with the state-reported data convinced us of a few things:

- We still need better data.
- State reported data is inconsistent.
- We need source and cause of release data included in USEPA's Performance Measures.

Problem solving is a pretty simple process. Step 1: Identify the problem. Step 2: Fix it. Albert Einstein was quoted as saying that if he had an hour to save the world, he would spend 55 minutes defining the problem and only 5 minutes finding the solution. Developing a solution to a problem before knowing the problem is just gambling—hoping to get lucky. We need better data to define our problem.

As an industry, we should be focused on stopping leaks from the greatest known source, which if the states data was accurate, would be tanks. But we *know* tanks are not our biggest problem.

The published data does do a great job of identifying a significant problem: the number one source of releases and the number one cause of releases is UNKNOWN! We need to define our problem.

As an industry we will reduce our risks if we do a better job of identifying the primary sources and causes of releases in currently active tanks. Historic releases and current releases must be separated.

Unknown source releases may have been discovered long after the occurrence or may not be from only one source. Possible explanations for these 'unknown' sources/causes may include confusion over the age of the release when reported, the proximity of previously closed tanks, the responsibility for a spill (e.g. customer/owner), the existence of other contaminants (e.g. on-site sump-water disposal), or lazy reporting.

If you don't know the source, you can't know the cause. Education, better data acquisition, and documentation are the keys to reducing this category. We need to develop a better process for all states to determine and report on source and cause of releases. We also need a better national reporting system.

As an insurance carrier, if we used state published data, we would have to focus on tanks and unknowns as the driving underwriting factors. But we know that items such as single vs. double-walled piping, uncontained dispensers vs. UDC systems, electronic line-leak detection vs. mechanical or no line-leak detection, and poor housekeeping vs. good housekeeping play greater roles than tanks in determining the risk presented by each UST facility.

If we get better data, we can reduce UST system risks. If we don't get better data, we may be fixing what isn't broken. ■

■ **Closing LUST Sites with Contamination** *from page 21*

conductivity. The electrical conductivity of silt and clay is usually much higher than that of sands and gravels. The hydraulic profiling tool measures the pressure that develops as water is pumped from the push tool into the aquifer at a fixed rate. The lower the pressure, the higher the hydraulic conductivity.

In Figure 5, the first 12 feet of sediment have high values for electrical conductivity and high values for injection pressure, indicating silts and clays with low hydraulic conductivity. Between 12 and 70 feet, the values of electrical conductivity are much lower, and the injection pressure only increases to match the expected pressure of the groundwater and the atmosphere above the probe, indicating sands and gravels. This information was collected in less than an hour at a location on one of the author's research sites.

Tools are available in the marketplace to determine the vertical distribution of hydraulic conductivity, the vertical distribution of LNAPL hydrocarbons, and the vertical distribution of dissolved contamination. This information can be used to evaluate a site and determine if active remediation has protected the aquifer as a source of drinking water and determine if residual contamination can safely be left in place. ■

John Wilson worked for USEPA as a research microbiologist for thirty-four years. John retired from the USEPA in 2014. He is now the Principal Scientist at Scissortail Environmental Solutions, LLC. He can be reached at: john@scissortailenv.com.

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TANK NEWS FROM NEIWPCC........

NEIWPCC is pleased to offer several training webinars through the summer of 2019. Our UST Inspector Training Webinar Series will include training on Financial Responsibility, Cathodic Protection, Automatic Tank Gauges, and Emerging Fuels. Representatives from state agencies, USEPA, and industry will be speaking, and the webinar recordings will be added to our online archive. To access information on upcoming training webinars or to view an archived webinar, please visit the UST Inspection and Release Prevention page on the NEIWPCC website: *https://neiwpcc.org/our-programs/underground-storage-tanks/ust-training-resources-inspection-leak-prevention/*.

For those interested in our LUST Corrective Action Webinar Series, NEIWPCC recently provided a training webinar on Risk Based Corrective Action (RBCA). This webinar followed RBCA – Unit 1, which covered the history and fundamental concepts of RBCA. For Unit 2, we discussed advanced considerations and institutional controls related to RBCA. Ravi Arulanantham returned to guide the discussion for Unit 2, and we heard perspectives from state regulators in California, Colorado, and Missouri. To access information on upcoming training webinars or to view an archived webinar, please visit the LUST Corrective Action page on the NEIWPCC website: *https://neiwpcc.org/our-programs/underground-storage-tanks/lust-training-resources-corrective-action/*

If you would like to be added to our distribution list to receive invitation emails for future training webinars, or if you have any questions about NEIWPCC's UST/LUST program, please contact Drew Youngs at DYoungs@neiwpcc.org.