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Petroleum Program Guidance

Welcome

Welcome to the OPS Petroleum Program Guidance. We are excited to share this dynamic web-based resource with you, as it provides all of our guidance in one place, which means you no longer have to search through separate PDFs to find the information you need.

Our goal for this guidance is that it is valuable to you and easy to use, whether you need to know how to operate your tanks, what to do if you have a release or how to get reimbursed for cleanup costs.

Please note: this guidance does not supersede Colorado Petroleum Storage Tank Regulations and Statutes; rather, it describes our expectations for how you will comply with these rules.

Don't see something you need assistance with? Have an idea for a new topic? Click on the button below to share your suggestions or comments with us.

Guidance Feedback

How To Use this Guidance

You can click on topics of interest on the Contents tab on the left side of the screen, use hyperlinks to references, access a glossary of terms and use the search tool in the upper right.

NEW! Updates to Corrosion Prevention and Release Closure Criteria

To ensure that you see the most recent version of guidance, you may need to clear your browser's cache (browser history) and reopen the guidance.

Introduction

Owning and operating a fuel storage facility is a big responsibility. Operational compliance helps prevent fuel releases, promote market equality and provide a safe fueling environment for customers. If you are considering becoming an owner of a petroleum storage system, have you done your due diligence[1]

?

It is important to get to know the Colorado Petroleum Storage Tank regulations. These rules have been developed with local stakeholder input. Other rules, including federal regulations, Colorado air quality regulations, national fire protection codes and national weights and measures standards may also apply to your site.

Staying in compliance minimizes the likelihood of having a costly release and helps ensure reimbursement from the Petroleum Storage Tank Fund if a release occurs.

Here are the answers to some commonly asked questions to get you started.

Are my tanks regulated?

Most **USTs**[2] (underground storage tanks) with a capacity greater than 110

---

[1] An environmental site assessment may help you discover contamination before you own the site. Reviewing the existing tank system's compliance records will help you understand the site's history.

[2] Any tank system (including all product piping and ancillary equipment) that contains regulated substances that is 10% or greater beneath the ground surface.

gallons that contain petroleum products are regulated.

A few notable UST exemptions include:

- On-site heating oil tanks,
- Farm tanks with a capacity of 1,100 gallons or less,
- Stormwater or wastewater collection systems,
- Oil-water separator tanks,
- Process flow-through tanks.

ASTs[1] (aboveground storage tanks) with a capacity between 660 and 39,999 gallons that contain fuel or lubricants are regulated.

A few notable AST exemptions include:

- Tanks located on farms or residential properties
- Tanks associated with oil or gas production
- On-site heating oil tanks
- Tanks at construction or earth-moving sites

A full list of exemptions can be found in the Colorado Petroleum Storage Tank regulations.

How often do I submit compliance records?

OPS currently requests compliance records as part of an inspection. Compliance records are also required as part of applying for reimbursement from the Petroleum Storage Tank Fund.

Request a visit

Would you like a visit from an OPS representative in order to learn more about your tank system? If so, you may request a visit.

[1] All aboveground storage tanks at a facility, all the connected piping and ancillary equipment, all loading facilities, and all containment systems, if applicable

What are the differences between temporary closure and permanent closure?
A storage tank is considered by law to be "in use" if there is more than one inch of product in it. A storage tank can be temporarily closed for up to 12 months by being emptied to less than one inch of product and notifying OPS. A tank can be permanently closed by notifying OPS, emptying and inerting[1] the tank, and either closing the tank in place or removing it.

What State fees are associated with operating a storage tank system?

Underground Storage Tank	Aboveground Storage Tank
$150 installation or upgrade permit application review fee	No installation or upgrade permit application review fee
$35 per tank per year registration fee	$35 per tank per year registration fee

What should I do if I think I've been cheated at the pump?
Call our Consumer Complaint line at (303) 866-4967 or our Technical Assistance line at (303) 318-8547 if you have questions about the accuracy, quality, safety or environmental protection of fuel storage or dispensing equipment in Colorado.

Who can help me with an environmental site assessment?
OPS maintains a database of Recognized Environmental Professionals that you can view to choose a consultant to assist you with an environmental assessment.

[1]removing the volatile component of a tank interior or otherwise making the tank safe for removal.

Additional Resources

US EPA Office of Underground Storage Tanks - visit the Federal UST program webpage to learn about the 2015 revisions to UST regulations and read useful guidance, such as EPA's Musts for USTs.

UST Installer Requirements

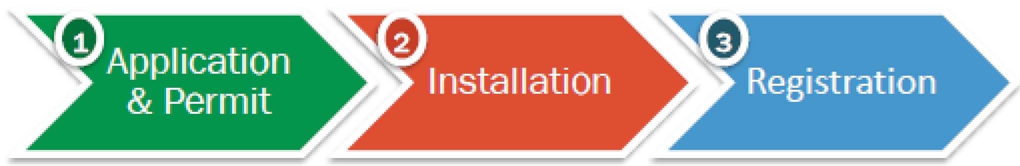
Installation of regulated **underground storage tank**[1]s may only be conducted by certified installation companies. To become a certified installer, complete this form.

If you are installing new or used regulated storage tanks, adding new system components that didn't exist before, adding secondary containment for piping interstitial monitoring, replacing or relocating underground or aboveground piping, or installing a tank within a tank, it is necessary to complete our Installation/Upgrade Permit Application in order to request a permit for that work. OPS will review the application, ask any necessary questions in order to understand the proposed changes, and issue a permit once the application is acceptable. Following permit issuance, it is important to keep OPS informed of the project's progress so we can schedule installation and startup inspections. These inspections help ensure a high quality and compliant system installation or upgrade.

[1] any one or combination of tanks, including underground pipes connected thereto, except those exempted in statute and these regulations, that is used to contain an accumulation of regulated substances and the volume of which, including the volume of underground pipes connected thereto, is ten percent or more beneath the surface of the ground and is not permanently closed

Installation Permit and Registration

All regulated storage tank systems must have an installation permit (which requires an application for the permit) and must be registered. A properly designed and installed tank system may prevent costly releases to the environment. The information below explains what is required to obtain an installation permit and register a tank system.



The following are installation and registration requirements for all regulated storage tank systems.

- An OPS installation permit
- Local Fire Department notification of the installation
- An installation inspection request
- Payment of the installation application/inspection fee
- Documentation of secondary tightness testing
- Registration within 30 days of putting regulated substances into the tanks

All regulated tank systems must be permitted through OPS prior to construction/installation and registered after installation. Complete and submit the appropriate AST or UST Installation Application to OPS to begin the process.

Tips for Completing the Installation Application

> **Do not submit the Registration form with the Installation Application. The Registration form should be submitted after the tanks are installed and in use (with regulated substance in the tanks).**

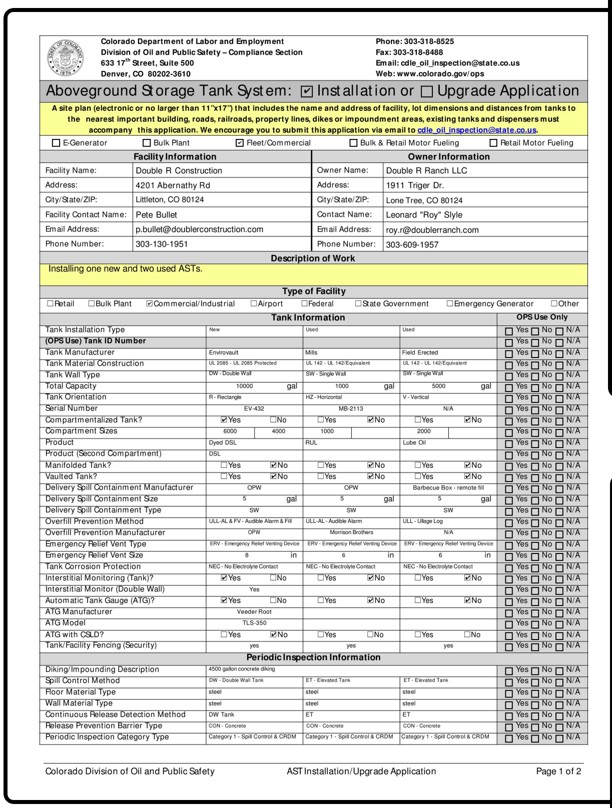
- Download and save a copy of the form onto your computer hard drive or flash drive with an appropriate name where you can review and complete it at a later time.
- Fill out all fields. In the event that the field is not applicable, use "N/A." Lack of information will slow the approval process.
- Electronic signatures are acceptable for emailed applications. Mailed applications should be signed in ink, preferably blue ink.
- A Site Plan (electronic or printed smaller than 11 x 17) must accompany the application. It must include the following items:
  - The name and address of facility
  - Lot dimensions
  - Distances from tanks to nearest important building, roads, railroads, property lines, dikes/impoundment areas, existing tanks and dispensers
- Submit the application and site plan via email to cdle_oil_inspection@state.co.us or mail it to the address listed on the application. ***Submit the application with the site plan and review fee at least 20 working days[1] prior to beginning construction.***

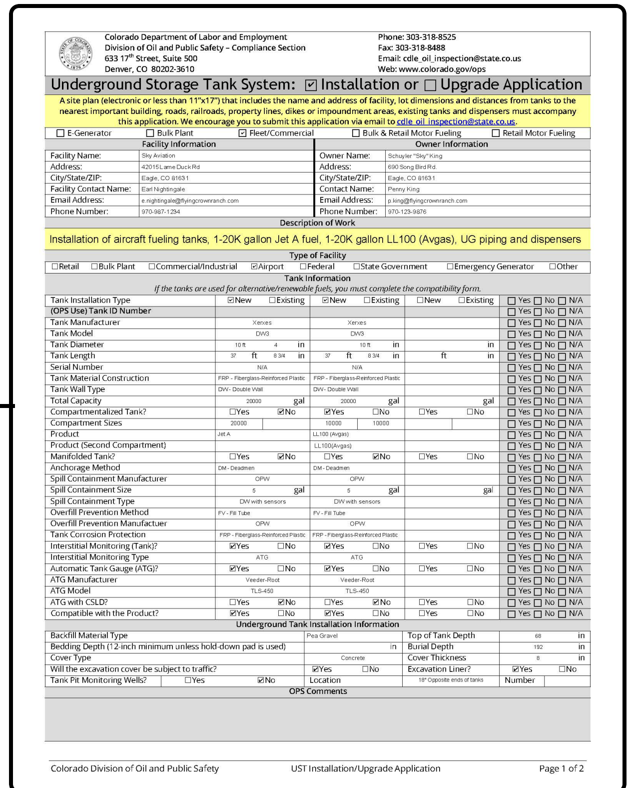
Installation Application Examples

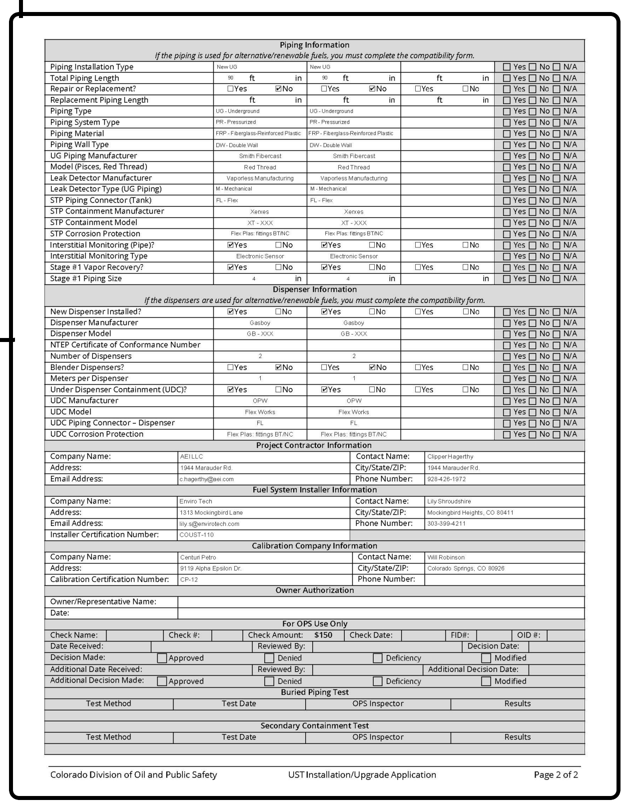
Click on the images below for examples of completed installation applications.

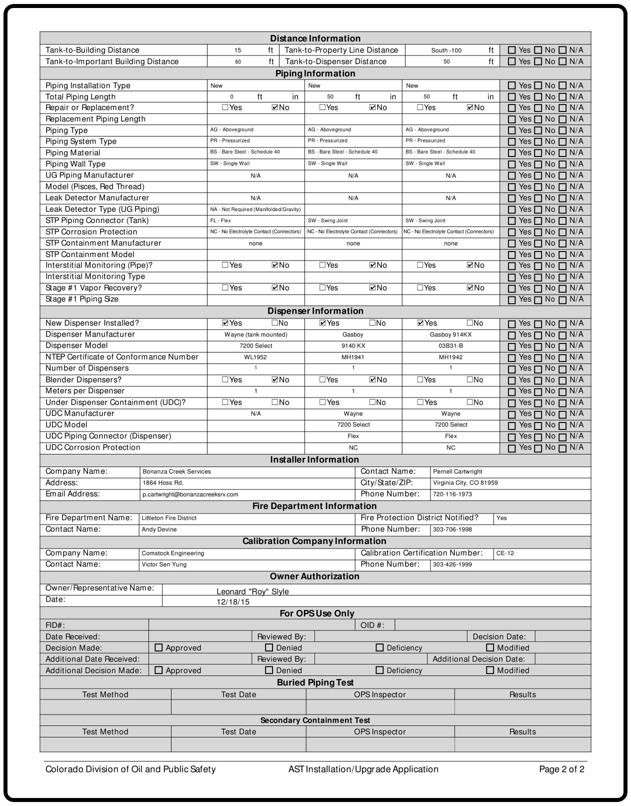
AST UST

[1] Monday through Friday, excluding state and federal holidays.


Colorado Department of Labor and Employment
Division of Oil and Public Safety – Compliance Section
633 17th Street, Suite 500
Denver, CO 80202-3610
Phone: 303-318-8525
Fax: 303-318-8488
Email: cdle_oil_inspection@state.co.us
Web: www.colorado.gov/ops
Aboveground Storage Tank System: ☑ Installation or ☐ Upgrade Application
Facility Information
Owner Information
Double R Construction
4201 Abernathy Rd
Littleton, CO 80124
Pete Bullet
Double R Ranch LLC
1911 Triger Dr.
Lone Tree, CO 80124
Leonard "Roy" Slyle
Description of Work
Installing one new and two used ASTs.
Type of Facility
Tank Information
Periodic Inspection Information
Colorado Division of Oil and Public Safety
AST Installation/Upgrade Application
Page 1 of 2


Colorado Department of Labor and Employment
Division of Oil and Public Safety – Compliance Section
Underground Storage Tank System: ☑ Installation or ☐ Upgrade Application
Facility Information
Owner Information
Description of Work
Installation of aircraft fueling tanks, 1-20K gallon Jet A fuel, 1-20K gallon LL100 (Avgas), UG piping and dispensers
Type of Facility
Tank Information
Underground Tank Installation Information
OPS Comments
Colorado Division of Oil and Public Safety
UST Installation/Upgrade Application
Page 1 of 2


Piping Information
Dispenser Information
Project Contractor Information
Fuel System Installer Information
Calibration Company Information
Owner Authorization
For OPS Use Only
Buried Piping Test
Secondary Containment Test
Colorado Division of Oil and Public Safety
UST Installation/Upgrade Application
Page 2 of 2



Distance Information				
Tank-to-Building Distance	15 ft	Tank-to-Property Line Distance	South -100 ft	☐ Yes ☐ No ☐ N/A
Tank-to-Important Building Distance	60 ft	Tank-to-Dispenser Distance	50 ft	☐ Yes ☐ No ☐ N/A

Piping Information				
Piping Installation Type	New	New	New	☐ Yes ☐ No ☐ N/A
Total Piping Length	0 ft in	50 ft in	50 ft in	☐ Yes ☐ No ☐ N/A
Repair or Replacement?	☐Yes ☑No	☐Yes ☑No	☐Yes ☑No	☐ Yes ☐ No ☐ N/A
Replacement Piping Length				☐ Yes ☐ No ☐ N/A
Piping Type	AG - Aboveground	AG - Aboveground	AG - Aboveground	☐ Yes ☐ No ☐ N/A
Piping System Type	PR - Pressurized	PR - Pressurized	PR - Pressurized	☐ Yes ☐ No ☐ N/A
Piping Material	BS - Bare Steel - Schedule 40	BS - Bare Steel - Schedule 40	BS - Bare Steel - Schedule 40	☐ Yes ☐ No ☐ N/A
Piping Wall Type	SW - Single Wall	SW - Single Wall	SW - Single Wall	☐ Yes ☐ No ☐ N/A
UG Piping Manufacturer	N/A	N/A	N/A	☐ Yes ☐ No ☐ N/A
Model (Pisces, Red Thread)				☐ Yes ☐ No ☐ N/A
Leak Detector Manufacturer	N/A	N/A	N/A	☐ Yes ☐ No ☐ N/A
Leak Detector Type (UG Piping)	NA - Not Required (Manifolded/Gravity)			☐ Yes ☐ No ☐ N/A
STP Piping Connector (Tank)	FL - Flex	SW - Swing Joint	SW - Swing Joint	☐ Yes ☐ No ☐ N/A
STP Corrosion Protection	NC - No Electrolyte Contact (Connectors)	NC - No Electrolyte Contact (Connectors)	NC - No Electrolyte Contact (Connectors)	☐ Yes ☐ No ☐ N/A
STP Containment Manufacturer	none	none	none	☐ Yes ☐ No ☐ N/A
STP Containment Model				☐ Yes ☐ No ☐ N/A
Interstitial Monitoring (Pipe)?	☐Yes ☑No	☐Yes ☑No	☐Yes ☑No	☐ Yes ☐ No ☐ N/A
Interstitial Monitoring Type				☐ Yes ☐ No ☐ N/A
Stage #1 Vapor Recovery?	☐Yes ☑No	☐Yes ☑No	☐Yes ☑No	☐ Yes ☐ No ☐ N/A
Stage #1 Piping Size				☐ Yes ☐ No ☐ N/A

Dispenser Information				
New Dispenser Installed?	☑Yes ☐No	☑Yes ☐No	☑Yes ☐No	☐ Yes ☐ No ☐ N/A
Dispenser Manufacturer	Wayne (tank mounted)	Gasboy	Gasboy 914KX	☐ Yes ☐ No ☐ N/A
Dispenser Model	7200 Select	9140 KX	03B31-B	☐ Yes ☐ No ☐ N/A
NTEP Certificate of Conformance Number	WL1952	MH1941	MH1942	☐ Yes ☐ No ☐ N/A
Number of Dispensers	1	1	1	☐ Yes ☐ No ☐ N/A
Blender Dispensers?	☐Yes ☑No	☐Yes ☑No	☐Yes ☐No	☐ Yes ☐ No ☐ N/A
Meters per Dispenser	1	1	1	☐ Yes ☐ No ☐ N/A
Under Dispenser Containment (UDC)?	☐Yes ☐No	☐Yes ☐No	☐Yes ☐No	☐ Yes ☐ No ☐ N/A
UDC Manufacturer	N/A	Wayne	Wayne	☐ Yes ☐ No ☐ N/A
UDC Model		7200 Select	7200 Select	☐ Yes ☐ No ☐ N/A
UDC Piping Connector (Dispenser)		Flex	Flex	☐ Yes ☐ No ☐ N/A
UDC Corrosion Protection		NC	NC	☐ Yes ☐ No ☐ N/A

Installer Information			
Company Name:	Bonanza Creek Services	Contact Name:	Pernell Cartwright
Address:	1864 Hoss Rd.	City/State/ZIP:	Virginia City, CO 81959
Email Address:	p.cartwright@bonanzacreeksrv.com	Phone Number:	720-116-1973

Fire Department Information			
Fire Department Name:	Littleton Fire District	Fire Protection District Notified?	Yes
Contact Name:	Andy Devine	Phone Number:	303-706-1998

Calibration Company Information			
Company Name:	Comstock Engineering	Calibration Certification Number:	CE-12
Contact Name:	Victor Sen Yung	Phone Number:	303-426-1999

Owner Authorization	
Owner/Representative Name:	Leonard "Roy" Slyle
Date:	12/18/15

For OPS Use Only						
FID#:		OID #:				
Date Received:		Reviewed By:		Decision Date:		
Decision Made:	☐ Approved	☐ Denied	☐ Deficiency	☐ Modified		
Additional Date Received:		Reviewed By:		Additional Decision Date:		
Additional Decision Made:	☐ Approved	☐ Denied	☐ Deficiency	☐ Modified		

Buried Piping Test			
Test Method	Test Date	OPS Inspector	Results

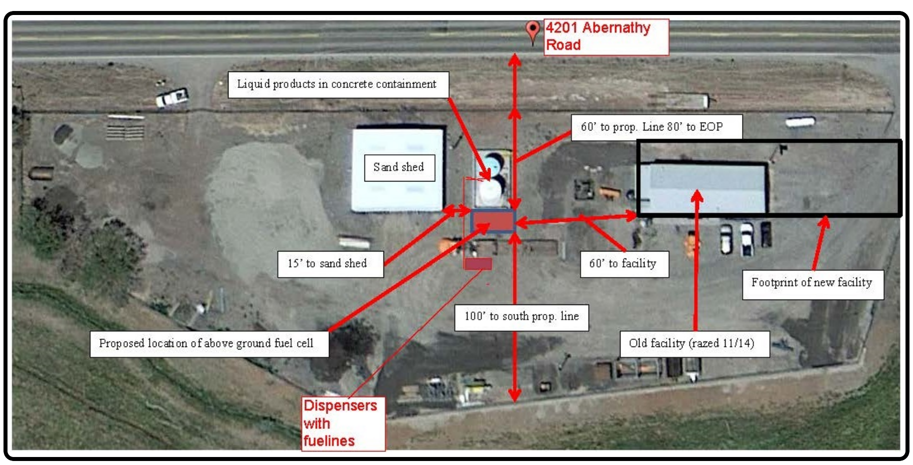
Secondary Containment Test			
Test Method	Test Date	OPS Inspector	Results

Colorado Division of Oil and Public Safety AST Installation/Upgrade Application Page 2 of 2

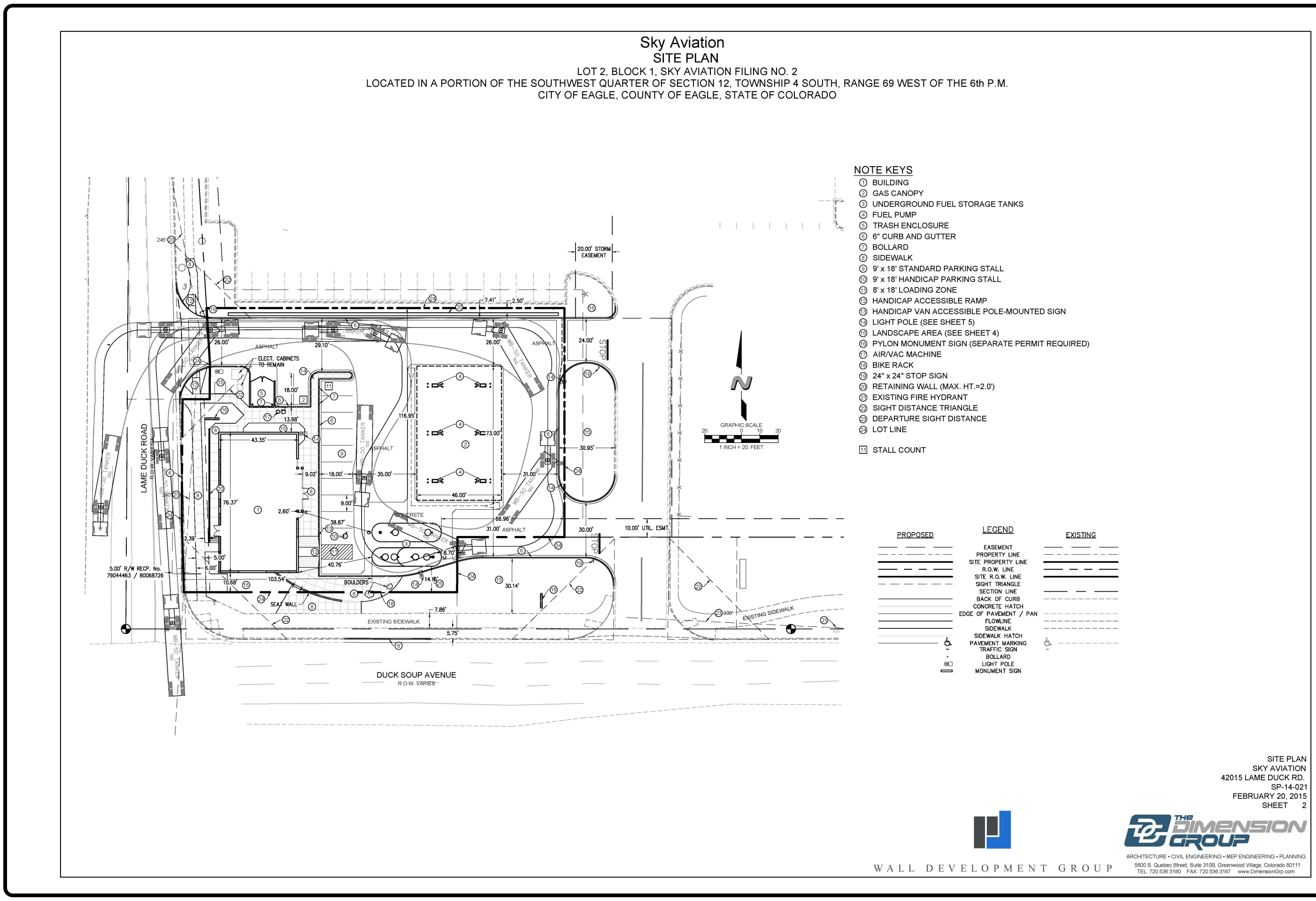
Site Plan Examples

Click on the images below for examples of site plans.

AST



UST



Application Fee

There is a $150 application fee for the review of a UST system installation permit application. There is no fee for AST system installation permit applications.

Send your payment to the address listed on the application.

If you email the application, reference the check information for the check that was mailed to ensure quick processing.

Alternative Fuel Compatibility Form

A UST or AST system must be made of, or lined with, materials that are compatible with the substance stored therein. Product piping, including piping within the dispensers and containment sumps, is considered part of the tank system and needs to be compatible with the substance stored and dispensed through it. All tank systems that store and dispense Alternative Fuel[1]/Renewable fuel[2] must be fully compatible with those fuels. Submit the Alternative/Renewable Fuel Compatibility form to OPS when switching to alternative or renewable fuels in a tank system.

Submit the form via email to cdle_oil_inspection@state.co.us or mail it to the address listed on the form.

Change of Storage of Regulated Substance

If the regulated substance in a tank system will be changed, OPS must be notified a minimum of 30 calendar days prior to the change. The notification can be made by completing this form or by filling out the pdf version and emailing it to cdle_oil_inspection@state.co.us .

Installation Application Permit Review

The turnaround time for a review is generally 20 working days. An incomplete application will be returned. The install permit approval (or denial) will be sent to the email address provided on the application, with details regarding the Installation Permit Application approval or denial.

Tips to Minimize the Time between Submitting the Installation Permit Application and Receiving Your Installation Permit

- Complete all applicable fields on the application form, including providing accurate information for the following fields:
  - Facility
  - Owner (including a valid email address)

---

[1] motor fuel that combines petroleum-based fuel products with renewable fuels

[2] motor vehicle fuel that is produced from plant or animal products or wastes, as opposed to fossil fuel sources.

  - Fuel system installer company
  - Fire department jurisdiction
  - Calibration company
  - Owner certification: title, owner type (new or current), phone number, signature and date for either the owner/operator or signatory authority
- Electronically sign the application if you are submitting it via email; sign it in blue ink if you are going to mail it

An installation permit is only valid for up to six months after it is issued. [Notify your local OPS Inspector] at least 72 hours before on-site tank system integrity testing (for USTs) or before a regulated substance is delivered (for ASTs). All new and used ASTs and associated connections must be tested for tightness after installation/reinstallation and before being placed in service in accordance with manufacturer instructions, or NFPA 30 where no manufacturer instructions exist.

Any **person**[1] who owns a regulated tank system must notify OPS within 30 days of the start of operation by submitting the completed AST or UST Registration form via email to cdle_oil_inspection@state.co.us or mailing it to the address listed on the form.

Registration Fee Payment

Owners or operators of USTs or ASTs regulated by OPS must register their tanks within 30 days after first using them to store a regulated substance and send the registration fee. A registration invoice for the number of tanks installed will automatically be generated and sent to the primary contact at the end of the month in which tanks are placed into "currently in use" status. Make payment to OPS within the 60-day period from the date indicated on the invoice.

Tips for Paying Registration Fees

- Tank registration fees need to be paid annually.
- OPS sends tank registration and renewal invoices to the owner at the same time each year.
- The registration and renewal fee is $35.00 per tank per year.
- These fees go to the Petroleum Storage Tank Fund, which is used to assist tank owners with cleaning up petroleum releases.
- Payments can be made by using the Storage Tank Online Payment System, which allows you to make a payment with a credit card.
- If you prefer not to use the online payment system, fees can be mailed to the following address:

CDLE OPS
PO Box 628

[1] A “person” is an individual, trust, firm, joint stock company, federal agency, corporation, state, municipality, commission, political subdivision of a state, or any interstate body. "Person" also includes a consortium, a joint venture, a commercial entity

Denver, CO 80201-0628

Additional Resources

[EPA Resources for Owners and Operators / Installation]

[NFPA-30 Flammable and Combustible Liquids Code]

[NFPA-30A Code for Motor Fuel Dispensing Facilities and Repair Garages]

[PEI-RP100]

Storage Tank System Design

Storage tank systems USTs[1] and ASTs[2] must prevent releases due to structural failure, corrosion, or spills and overfills for as long as the tank system is used to store regulated substances.[3]

Tank Design

Tank construction materials must be compatible[4] with the substance being stored.

Because the chemical and physical properties of renewable fuels (such as ethanol and biodiesel blends) and hazardous substances may make them more aggressive to certain tank system materials than petroleum, it is important that all tank system components in contact with these liquids are materially compatible.

When a UST will store diesel fuel containing more than 20% biodiesel or gasoline containing more than 10% ethanol, the tank owner/operator must demonstrate that all tank system components are compatible with the substance being stored by documenting manufacturer compliance.

[1]"Underground storage tank (UST) system" refers to an any one or combination of tanks - including connected underground pipes - except those exempted in statute and these regulations, that is used to contain an accumulation of regulated substances and the volume of which - including the volume of connected underground pipes - is ten percent or more beneath the surface of the ground and is not permanently closed, underground ancillary equipment, and containment system, if any.

[2]"Aboveground storage tank (AST) system" means any one or a combination of containers, vessels, and enclosures, including structures and appurtenances connected to them, constructed of non-earthen materials, including but not limited to concrete, steel, or plastic, which provide structural support, used to contain or dispense fuel products and the volume of which - including the pipes connected thereto - is ninety percent or more above the surface of the ground, is not permanently closed, and except those exempted by statute and regulations, all the connected piping and ancillary equipment, all loading facilities, and all containment systems if applicable.

PEI UST Component Compatibility Library

California EPA Manufacturer Compatibility Statements

UL Online Certifications Directory

Atmospheric tanks[1] cannot be used to store liquids at temperatures at or above their boiling point, and must be designed and constructed in accordance with recognized engineering standards.

USTs

USTs must meet the design standards, specifications, and requirements provided in OPS storage tank regulations, U.S. EPA regulations and NFPA fire code.

Secondary containment and interstitial monitoring is required for all new underground tank installations. If an existing underground tank is replaced, the secondary containment and interstitial monitoring requirements apply only to the replaced underground tank. These requirements do not apply to repairs meant to restore an underground tank to operating condition.

Any portion of an underground tank that routinely contains product must be protected from corrosion in accordance with a code of practice developed by a nationally recognized association or independent testing laboratory, such as being:

Constructed of fiberglass-reinforced plastic.

Standard for Glass-Fiber Reinforced Plastic Underground Storage Tanks for Petroleum Products, Alcohols, and Alcohol-Gasoline Mixtures

Underwriter's Laboratories of Canada CAN4-S615-M83, Standard for Reinforced Plastic Underground Tanks for Petroleum Products

[1] A storage tank that has been designed to operate at pressures from atmospheric through a gauge pressure of 1.0 psi measured at the top of the tank.

Constructed of steel[1] and cathodically protected.[2]

NACE. Corrosion Control of Underground Storage Tank Systems by Cathodic Protection

ANSI/UL 1746, Standard for External Corrosion Protection Systems for Steel Underground Storage Tanks

Pre-engineered cathodic protection systems[3]

Composite tanks[4]

Jacketed tanks[5]

Tanks that are designed and intended for aboveground use must not be used as underground tanks.

ASTs

ASTs must meet the design standards, specifications, and requirements provided in OPS storage tank regulations and NFPA fire code.

API Specification 12B, Bolted Tanks for Storage of Production Liquids

API Specification 12D, Field Welded Tanks for Storage of Production Liquids

API Specification 12F, Shop Welded Tanks for Storage of Production Liquids

API Standard 650, Welded Steel Tanks for Oil Storage

ANSI/UL 80, Standard for Steel Tanks for Oil Burner Fuel

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[1] UL 58, Standard for Steel Underground Tanks for Flammable and Combustible Liquids

[2] Cathodic protection (CP) is a method of controlling the corrosion of a metal structure by making it the cathode of an electrochemical cell. The simplest method connects a metal structure that is to be protected to a more easily corroded "sacrificial metal," which will serve as the anode of the electrochemical cell. Once connected in an electrically continuous path, the sacrificial metal corrodes rather than the metal structure being protected.

[3] Suitably-coated steel USTs with factory-attached sacrificial anodes) STI-P3

[4] Steel USTs with a factory applied non-metallic cladding/lamination bonded directly to the tank STI ACT-100

[5] Steel USTs with an interstitial separation between the tank and non-metallic outer layer STI Permatank

ANSI/UL 142, Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids

UL 2080, Standard for Fire Resistant Tanks for Flammable and Combustible Liquids

ANSI/UL 2085, Standard for Protected Aboveground Tanks for Flammable and Combustible Liquids"

Tanks constructed of combustible materials (such as plastic) are subject to OPS approval and are limited to use where:

- They are required by the properties of the liquid stored
- They will store Class IIIB liquids above ground in areas not exposed to a spill or leak of Class I or Class II liquids
- They will store Class IIIB liquids inside a building that is protected by an approved automatic fire extinguishing system

CLASSIFICATION OF LIQUIDS

Definition	*Classification*	*Flash Point (°F)*	*Examples*
Flammable Liquid (Closed-cup flash point < 100°F)	CLASS IA	< 73 (Boiling point < 100°F)	Gasoline, 100LL AvGas
	CLASS IB	< 73 (Boiling point ≥ 100°F)	
	CLASS IC	≥ 73and < 100	
Combustible Liquid (Closed-cup flash point ≥ 100°F)	CLASS II	≥ 100 and < 140	#1 & #2 Diesel, Kerosene
	CLASS IIIA	≥ 140 and < 200	Lubricating Oils
	CLASS IIIB	≥ 200	

Tanks that are designed and intended for underground use must not be used as aboveground tanks.

Ask the experts

Repurposing underground tanks as aboveground tanks: A dangerous game

"Damaged tank from explosion: Tank ends are bowed outward. No emergency venting evident. Small grinder with wire brush wheel near-by."—Hank Moore, Merced County Fire Marshal

Piping Design

Piping materials must be compatible[1] with the substance that it will contain, and must be maintained liquidtight.

Piping must be designed and constructed in accordance with recognized engin-eering standards.

Underground piping must meet the design standards, specifications, and requirements provided in OPS storage tank regulations, U.S. EPA reg-ulations and NFPA fire code.

Secondary containment and interstitial monitoring is required for all new piping installations, including piping to remote fill connections.

For replaced[2] piping, secondary containment and interstitial monitoring is required for the]total length[3] of piping connected to a single UST whenever

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[1]"Compatible" means the ability of two or more substances to maintain their respective physical and chemical properties upon contact with one another for the design life of the tank system under conditions likely to be encountered.

[2]"Replace" means to remove and put back in any amount of piping connected to an UST system.

[3]The total length of piping connected to a single underground tank includes the length piping from that tank to the farthest connected dispenser, including piping runs between dispensers connected to that tank.

more than 50% or 50 feet (whichever is less) of the piping connected to that tank is replaced.

Installation of new or replaced piping will require the installation of containment sumps (under-dispenser [UDC], submersible turbine pump [STP] or transition) on both ends of the secondarily contained pipe for interstitial monitoring.

Piping that routinely contains product and is in contact with the ground must be protected from corrosion in accordance with a code of practice developed by a nationally recognized association or independent testing laboratory, such as being:

Constructed of fiberglass-reinforced plastic or other non-metallic material.
UL 971, Standard for Nonmetallic Underground Piping For Flammable Liquids

UL 567, Standard for Emergency Breakaway Fittings, Swivel Connectors and Pipe-Connection Fittings for Petroleum Products and LP-Gas

Piping Secondary Containtainment and Interstitial Monitoring Required For:

NOTE: For piping replacements, ***replacement length*** *and* ***total length*** *of product piping connected to the individual tank must be known*

Type of Work	Planned Amount Being Installed or Replaced	Amount Required	
New Piping (new or existing tank)	Any amount	Required for all product piping and remote fill piping	X
Replaced Piping	***replacement length*** > 50 ft	Required for ***total length*** of product piping connected to the tank	X
Replaced Piping	***replacement length*** > 50% of ***total length***	Required for ***total length*** of product piping connected to the tank	X
Replaced Piping	***replacement length*** ≤ 50 ft and ≤ 50% of ***total length***	Not required	

UL 567-A, Standard for Emergency Breakaway Fittings, Swivel Connectors and Pipe-Connection Fittings for Gasoline and Gasoline/Ethanol Blends with Nominal Ethanol Concentrations up to 85 Percent (E0 - E85)

UL 567B, Standard for Emergency Breakaway Fittings, Swivel Connectors and Pipe-Connection Fittings for Diesel Fuel, Biodiesel Fuel, Diesel/Biodiesel Blends with Nominal Biodiesel Concentrations up to 20 Percent (B20), Kerosene, and Fuel Oil

Standard for Nonmetallic Underground Piping for Flammable and Combustible Liquids

Standard for Flexible Underground Hose Connectors for Flammable and Combustible Liquids

Constructed of steel[1] and cathodically protected[2].
NACE SP0285-2011. Corrosion Control of Underground Storage Tank Systems by Cathodic Protection

Aboveground piping must meet the design standards, specifications, and requirements provided in OPS storage tank regulations and NFPA fire code. This includes all valves, fittings, connectors, and all other pressure-containing parts.
Must meet ASME B31, International Code For Pressure Piping Systems requirements.

Cast iron, brass, copper, aluminum, malleable iron, and similar materials can only be used on tanks storing Class IIIB liquids where the tanks are located outdoors and are not within a diked area or drainage path of a tank storing a Class I, Class II, or Class IIIA liquid.

[1] International Code For Pressure Piping Systems

[2] Cathodic protection (CP) is a method of controlling the corrosion of a metal structure by making it the cathode of an electrochemical cell. The simplest method connects a metal structure that is to be protected to a more easily corroded "sacrificial metal," which will serve as the anode of the electrochemical cell. Once connected in an electrically continuous path, the sacrificial metal corrodes rather than the metal structure being protected.

CLASSIFICATION OF LIQUIDS

Definition	*Classification*	*Flash Point (°F)*	*Examples*
Flammable Liquid (Closed-cup flash point < 100°F)	CLASS IA	< 73 (Boiling point < 100°F)	Gasoline, 100LL AvGas
	CLASS IB	< 73 (Boiling point ≥ 100°F)	
	CLASS IC	≥ 73and < 100	
Combustible Liquid (Closed-cup flash point ≥ 100°F)	CLASS II	≥ 100 and < 140	#1 & #2 Diesel, Kerosene
	CLASS IIIA	≥ 140 and < 200	Lubricating Oils
	CLASS IIIB	≥ 200	

UST Operator Training

UST Operator Training is a requirement designed to ensure proper knowledge regarding operating and maintaining UST systems. Since its implementation in 2009, UST Operator Training has resulted in improved compliance rates and a reduction in petroleum releases.

All regulated UST systems must have Class A, Class B and Class C Operators. Click on the arrows below to learn more about the requirements for each operator class.

CLASS A OPERATOR

Class A Operator Requirements

- Holds the primary responsibility for operating and maintaining the UST system
- Manages resources and personnel to maintain compliance

CLASS B OPERATOR

Class B Operator Requirements

- Implements day-to-day aspects of operating, maintaining and record keeping for USTs at one or more facilities
- Can be employed directly by the tank own-

CLASS C OPERATOR

Class C Operator Requirements

- First line of response to events, such as alarms or other indications of emergencies caused by spills/releases from UST systems with regulatory requirements

- Should be, or be employed directly by, the tank owner/operator, not a third party contractor

er/operator or by a third party contractor

- Notifies the Class A and B Operator(s) and appropriate emergency responders when necessary
- At least one Class C Operator must be present during operating hours at attended facilities

Additional Information

- All owners/operators must notify OPS within 30 days of a change of either a Class A or Class B Operator.
- A tank owner/operator can choose to have different people fulfill each of the operator classes, or the tank owner/operator may choose to have the same person serve as the Class A, Class B and Class C Operator as long as the person meets the specific requirements of each class.
- In order to provide flexibility, OPS allows a tank owner/operator to hire an independent contractor to serve as the facility's Class B Operator, if desired. Contracting with a Class B Operator in this fashion can allow more time for a tank owner/operator to focus on other business management matters. However, OPS strongly recommends clear establishment of specific responsibilities to be handled by contracted Class B Operators, given that the tank owner/operator is ultimately responsible for operating in compliance with the Colorado Petroleum Storage Tank regulations.

- Certification as a Class A or Class B Operator can be achieved by passing classroom or online training offered by an OPS-approved trainer or by passing the International Code Council's Colorado UST System Class A or B Operator exam.
- Certified Class A or Class B Operators can train their company's Class C Operators. Tank owners/operators must keep copies of each Class C Operator's training certificate at the facility.
- There are no continuing education or retraining requirements unless a facility is significantly out of compliance.
- If a facility is significantly out of compliance, retraining of the A and/or B Operator may be required.

Tank System Operation

Conducting your routine inspections and staying on top of release detection requirements will go a long way toward preventing releases and ensuring a safe fueling environment for your customers. The information provided below should help you keep track of your inspection and testing requirements.

Operational requirements include:

- Monitoring tanks and lines for evidence of leaks
- Maintaining continuous corrosion protection on steel components
- Maintaining spill prevention equipment, such as spill buckets and overfill prevention devices

New Regulations Effective January 1, 2017

The Environmental Protection Agency (EPA) finalized its revisions to the Federal Underground Storage Tank Regulations in July 2015.

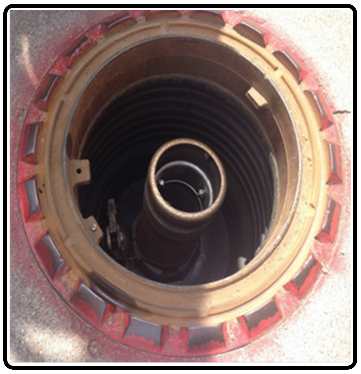
OPS already adopted a number of these changes in our 2008 regulation revisions, including:

- Secondary containment
- Operator training
- Monthly and annual compliance inspections
- Delivery prohibition

In order to further prevent petroleum releases, OPS adopted the remaining changes into the Colorado Storage Tank Regulations that went into effect on January 1, 2017.

The most significant new changes include the following periodic testing and inspections, which are required by January 1, 2020.

EVERY 3 YEARS



UST spill buckets and basins need integrity testing	Overfill prevention devices need to be inspected	Sumps used for interstitial monitoring of piping need integrity testing

EVERY YEAR

Release detection equipment must be inspected and tested

Additional changes include:

- As of January 1, 2017, **ball float valves** can no longer be used as a UST's primary overfill prevention device if they are found to be malfunctioning. Also, ball float valves cannot be the primary overfill prevention device in UST installations after January 1, 2017. A different overfill prevention device must be used (drop tube fill valve, audible alarm, etc.).
- Owners of existing USTs used solely for **emergency generators** must begin performing release detection on the tanks and piping by January 1, 2020. Owners of USTs installed after January 1, 2017, used solely for emergency

generators must perform release detection as soon as they are put into use.

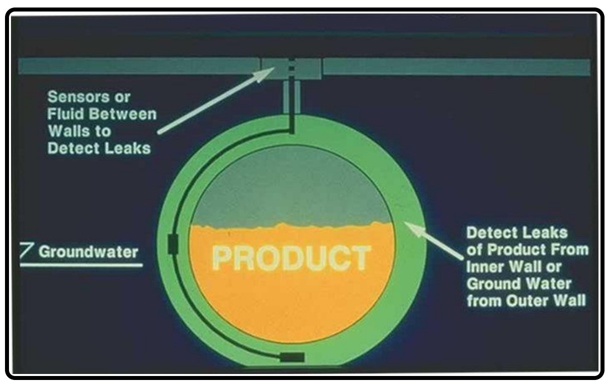
- Owners of **retail motor fuel meters (dispensers)** must notify OPS when meters are adjusted or put into service.

Details of these regulations are available on our website, and we encourage you to familiarize yourself with them and contact us to discuss any questions you may have.

Release Detection

Owners/operators must conduct release detection that can detect a release from any part of the tank system that routinely contains regulated substances. Ongoing release detection is required while tanks are in use. Common release detection methods are described below.

Interstitial Monitoring



Interstitial monitoring detects liquid in the space between the primary tank or product line and its secondary containment. This includes the interstitial space of double-walled tanks or lines, as well as secondary containment sumps, such as under-dispenser containment, piping transition sumps and submersible turbine pump containment areas.

This release detection method commonly uses electronic sensors placed in the secondary containment areas. It is critical that these sensors be installed and maintained appropriately in order to detect the presence of fuel.

All UST systems installed after August 1, 2008, are required to use monthly interstitial monitoring.

Automatic Tank Gauging

ATG (Automatic Tank Gauging) is an approved monthly monitoring method for tanks and pressurized lines. An ATG system consists of a probe installed inside each tank. The probes are wired to an electronic console that is mounted on the wall inside the facility. The automated process monitors and analyzes fuel levels to determine if there has been a suspected release. The console interprets and stores information transmitted by the probes. Most consoles have the ability to print out a tape with the results of the tests, and many can be connected to your computer network to allow electronic management of these records.

Statistical Inventory Reconciliation

SIR (Statistical Inventory Reconciliation) is an approved monthly monitoring method for tanks and lines. The tank owner/operator provides daily inventory, delivery and dispensing data to the SIR vendor. The vendor's computer software statistically analyzes the data provided to determine whether a tank system is leaking. The vendor provides a monthly report of that analysis to the tank owner. Using SIR does not relieve tank owners/operators of the requirement to equip all pressurized lines with operational in-line leak detectors and test the leak detectors every 12 months in accordance with the manufacturer's requirements.

Manual Tank Gauging

Manual tank gauging is an approved monthly monitoring method for a limited population of tanks. It may be used as the sole method of release detection for USTs of 1,000 gallons or less, or for USTs between 1,000 and 2,000 gallons if they are less than 10 years old and if tank tightness testing is performed at least every five years.

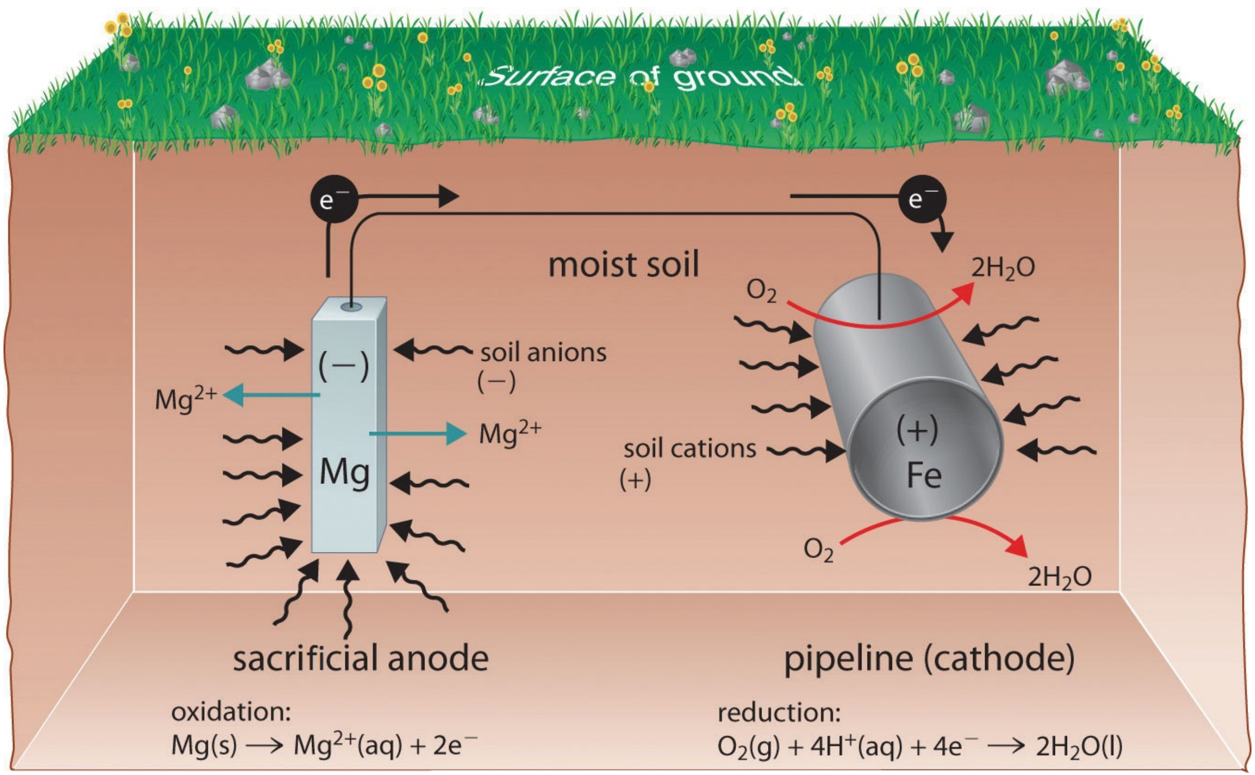
Tank liquid level measurements must be based on an average of two consecutive stick readings taken at least 36 hours apart. No liquid should be added to or removed from the tank during this period.

Corrosion Protection

You need corrosion protection if your system includes metallic components that are in contact with soil or water. The two common methods of corrosion protection are galvanic anodes and impressed current.

Galvanic Anodes

Smaller tank systems, steel pipe or isolated steel fittings typically utilize the installation of magnesium or zinc anodes. These anodes connect to the steel tank system components and create a negative current.



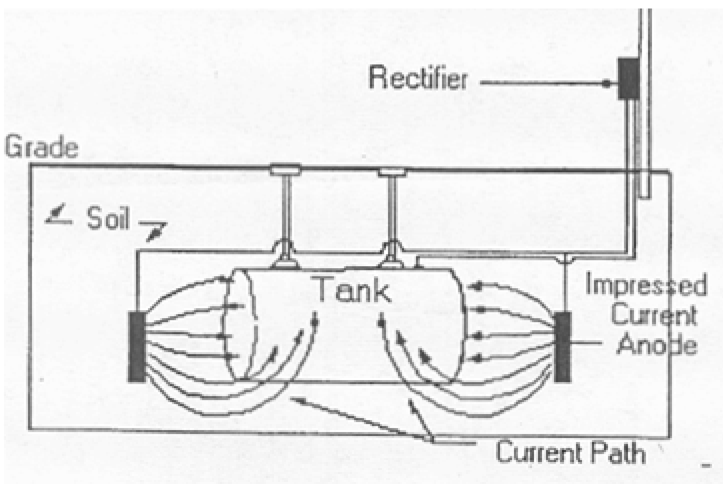
Galvanic anode system

This current is created by the difference in corrosion potential of dissimilar metals; the faster-corroding anode material will protect the steel, thus the term "sacrificial anode."

Sacrificial anode

Impressed Current

Tank systems that cannot be protected with galvanic anodes use an external applied electrical current to provide corrosion protection.



Impressed current system

A DC rectifier is used to control the power supply. The rectifier's negative terminal is connected to the tank system and the positive terminal is connected to anodes buried around the tank.

Impressed current rectifier

Spill Prevention

Spill Buckets

The spill containment device, also known as a spill bucket, is used to contain fuel during loading and unloading activities. This required piece of equipment is the first line of defense to preventing a release of petroleum to the environment.

AST spill bucket

UST spill bucket

It is important to keep your spill bucket clean and in good condition

> **Reminder: When responding to OPS records requests, remember to keep copies of any submittal for your records.**

A thorough inspection of the spill bucket is required during your monthly and annual inspections. During these inspections, ensure that your spill bucket is free of any fuel, water or debris. The spill bucket should be cleaned regularly, well-maintained and free of any visible damage.

A Spill Prevention, Control and Countermeasure Plan is required by the US EPA for qualifying[1] AST systems. All requests for information regarding Spill, Prevention, Control and Countermeasure Plans should be directed to the US EPA.

Overfill Prevention

Owners/operators must ensure safe delivery of fuel by:

- Painting your lids or clearly identify fill ports
- Sticking your tanks before delivery or calculating ullage
- Checking for functional overfill prevention devices

[1] A facility with an aggregate aboveground storage capacity of 1,320 gallons or greater.

Tank ullage is a method of determining the amount of unfilled space in a container, or the available tank capacity. This measurement is based on direct liquid level measurement that is converted to gallons. Product deliveries should not begin until the delivery operator has determined tank ullage.

USTs are required to have an overfill prevention device, such as a drop tube valve or ball float, if deliveries to the tank exceed 25 gallons.

If your AST is equipped with an overfill protection device or an audible overfill alarm that can be heard by the delivery operator, you meet the release prevention requirements and are not required to submit ullage logs to OPS.

If your AST is not equipped with one of these devices, the tank ullage and the amount of product delivered must be documented and the records should be maintained for a minimum of 12 months.

Overfill prevention alarm

Ongoing Maintenance

Keep water out of the fuel. Water can enter the tank in many ways. One of the most common pathways for water to enter the tank is through the drain valve located at the bottom of a spill bucket. Over time, the drain valve can leak and water in the spill bucket from storm runoff can enter the tank.

Are all the tank openings properly sealed? Ensure that all caps, plugs, fittings and flanges are sealed and watertight. To maintain fuel quality (free of water), it is recommended to gauge for water on a regular basis.

It is important to keep water out of your tank to prevent internal corrosion as shown here.

Record Keeping

OPS inspectors will request and review your compliance records as part of their State inspection of your facility. Please keep the following in mind when responding to the request for records.

- Make copies or scans of the applicable records when responding to a records request (keep your original copies).
- Communicate with your inspector if you have any issues acquiring and submitting the requested records by the requested date.

OPS recommends keeping these records indefinitely since they may be required as part of the compliance review for reimbursement applications to the Petroleum Storage Tank Fund. However, the following table lists the minimum record retention requirements:

Retention Time Frame	ASTs	USTs
1 year	• Inventory control records • Tank ullage documentation • Electronic/mechanical tank gauge calibration documentation • The type of product stored in each AST • Underground piping precision test records • Monthly and annual visual inspection records • Records of the operation of the cathodic protection system including results of 60-day inspections	• Tank tightness test results • Product piping tightness test results • Electronic/mechanical tank gauge calibration documentation • The type of product stored in each UST • Monthly and annual compliance inspection records • Records of the operation of the cathodic protection system including results of 60-day inspections
2 years	• Records showing any temporary closure status changes	• Records showing any temporary closure status changes
5 years	• Permits for the installation of new or used tanks and tank system upgrades • Records of repairs • Free product removal	• Permits for the installation of new or used tanks and tank system upgrades • Records of repairs • Free product removal

	records following any release of product	records following any release of product
Until Tank Closure	• Tank registration records or record of OPS Facility ID number • Formal/periodic AST inspection reports • Results from the last two cathodic protection system tests	• Tank registration records or record of OPS Facility ID number • Results from the last two cathodic protection system tests

Exemptions or Variances

Variances to the storage tank regulations are uncommon. However, if you provide a legitimate reason for an exemption and are unable to fulfill the requirements from any portion of regulation, a variance may be requested. OPS will not consider a variance without approval from the local fire department and evidence that measures are in place to demonstrate equal protection of public safety, human health and the environment.

When and How to Contact OPS

It is important that OPS has complete and accurate information regarding each facility's tank system and ownership. The following table outlines the most common reasons for contacting OPS.

Reason for Notification	Means of Notification
Change in ownership	UST or AST Transfer of Ownership form
Change in primary contact	Email, Telephone or Mail
Change in A/B Operator	A/B Operator Designation form (with a copy of the operator training certificate)

Change in product type	Change of Product form and Renewable Fuels Compatibility form (if necessary)
Change in release detection method	Email or Mail
Change in tank status – temporary closure	UST or AST Notice of Intent to Place Tanks into Temporary Closure
Change in tank status – permanent closure or change in service	Permanent Closure or Change in Service Notice
Change in tank status – placing back into service	UST or AST Notice of Intent to Place Tanks Back Into Service
Equipment failure, need for repair or upgrade	UST Minor Equipment Repair/Replacement Notification or USTor AST Upgrade Application
Suspected release conditions	OPS Technical Assistance Line – (303) 318-8547

AST Operation

Click on the arrows below for information about periodic requirements that should be completed to operate your AST system in compliance.

Monthly

Release Detection

Release detection for your aboveground piping is satisfied by your monthly visual inspections. If your AST system includes pressurized underground product piping, your release detection must meet the requirements for UST system piping.

Monthly Inspections

Monthly visual inspections are required for all visible AST system components, including piping if it is aboveground. The tank owner/operator is responsible for conducting these inspections, but the owner/operator can delegate this duty to a person familiar with the fueling system if necessary. An AST Monthly Visual Inspection Checklist should be completed each month. These records need to be maintained for a minimum of 12 months, but are recommended to be kept until the tank system is permanently closed.

Tips for Monthly AST Inspections

- Keep the diked area free of liquid, debris, combustible materials and drums/barrels (whether they are empty or full).
- Any product leakage or seeping connections should be addressed immediately. If product has come in contact with soil or groundwater, the tank owner/operator is required to report a suspected release to the OPS Technical Assistance Line at (303) 318-8547.
- If your AST system has impressed current cathodic protection, the system must be operated and maintained to continuously provide corrosion protection to the metallic components. The impressed current cathodic protection system must be inspected every 60 days to ensure that it is operating correctly; however, OPS recommends that this inspection be completed every 30 days. Rectifier readings will be required for submittal to OPS for the period specified in the Annual Compliance Package.

ASTs that are remote or inaccessible during the winter months

You may not be required to submit monthly visual inspection checklists for the winter months if you meet the following requirements.

- No more than two ASTs are in service at the facility.
- No AST at the facility has a capacity greater than 4,000 gallons.
- ASTs must be secondary containment (double-walled) tanks meeting UL142, UL2080, UL2085 or an equivalent standard. Dike tanks (single-walled tanks with integral diking) do not meet this requirement.
- ASTs must have an automatic interstitial liquid detector with remote monitoring capabilities installed. Results of remote leak detection monitoring during periods of inaccessibility must be documented at least monthly.

- During periods that the site is accessible, the required visual inspection must be conducted on a monthly basis and documented.

ASTs in Vaults

Monthly visual inspections require all sides of the tank to be visible in order to conduct the inspection.

Sometimes, this is not possible through vault openings, so the following alternative methods are available:

ASTs in vaults installed on or before September 30, 1994

- A visual inspection of all portions of the AST and interior of the vault that are visible through vault openings must be conducted on a monthly basis.
- A manned confined space entry must be performed annually to conduct a comprehensive visual inspection of the AST system. This inspection should include tank seams, piping, connections and appurtenances. Requirements for confined space entry can be found in OSHA's 29 CFR 1910. If the vault is equipped with a liquid detection system that activates an alarm in the presence of water or regulated substances, this comprehensive visual inspection can be performed once every two years.

ASTs in vaults installed after September 30, 1994

- The vault must be equipped with a liquid detection system that activates an alarm in the presence of water or regulated substances. Liquid detectors/sensors shall be located and installed according to the manufacturer's requirements.
- A visual inspection of all portions of the AST and interior of the vault that are visible through vault openings must be conducted on a monthly basis.
- A manned confined space entry must be performed once every two years to conduct a comprehensive visual inspection of the AST system and

documented. This inspection should include tank seams, piping, connections and appurtenances. Requirements for confined space entry can be found in OSHA's 29 CFR 1910.

- These tanks must include connections to allow venting of the vault prior to entry and continuous ventilation for those vaults containing Class I liquids.
- Contact OPS immediately after failed or inconclusive tank system tests and work with your contractor to identify, repair and retest the system. Submit the retest results to OPS.

Annually

Release Detection

If your AST system includes pressurized underground product piping, your release detection must meet the UST requirements for piping release detection.

Annual Inspections

An annual visual inspection is required for all visible AST system components (including piping if it is aboveground) and is intended to identify leaks and to monitor the condition of tanks, piping, secondary containment and equipment. The annual inspection is more thorough than the monthly visual inspections and is conducted in addition to them.

The tank owner/operator is responsible for conducting this inspection, but the owner/operator can delegate this duty to a person familiar with the fueling system if necessary. The inspection that an OPS inspector conducts at your facility is not a substitute for your annual visual inspection.

An AST Annual Visual Inspection Checklist should be performed within 12 months of the previous annual visual inspection and will be required for the period specified in the Annual Compliance Package.

Tips for Annual AST Inspections

- Maintain a functioning emergency vent. Your annual visual inspection is a good time to make sure the emergency vent is in good working condition. OPS recommends reviewing the American Petroleum Institute's Bulletin 2521 and Recommended Practice 576 for maintenance and inspection procedures.
- If electronic or mechanical tank gauges are used to determine tank liquid levels, the gauge is required to be calibrated on an annual basis or per the manufacturer's instructions. The tank gauge measurement should match manual tank gauge stick readings. These calibrations should be documented and the records should be maintained.

Every Three Years

Corrosion Protection Testing

The two common methods of corrosion protection - galvanic anodes and impressed current - must be tested by a qualified cathodic protection tester at least every three years to ensure adequate protection of all tank system components in contact with soil or water. Documentation of passing tests will be required for the period specified in the Annual Compliance Package.

Suction Piping Testing

An AST system with underground suction piping must have a line tightness test conducted at least once every three years. Safe or European suction piping does not require tightness testing if it meets all of the following criteria:

- Operates at less than atmospheric pressure
- Sloped so that product drains back into the storage tank

- Includes only one check valve in each suction line that is located directly below and as close as practical to the suction pump

Every 5 to 20 Years (Formal Periodic Inspections)

Formal periodic inspections and testing determine an AST's suitability for continued service. These inspections must be conducted by certified Steel Tank Institute SP001 inspectors according to the SP001 standard.

The SP001 inspection must be performed when you're installing a used AST or every 5 to 20 years for existing ASTs depending on the tank capacity, spill control and CRDM (Continuous Release Detection Method).

- Spill control is the means provided to control a catastrophic release and keep it from endangering adjacent structures, properties and waterways. Methods of spill control include diking, impounding and double-walled tanks.
- CRDM is a means of detecting a release of liquid through inherent design. Types of CRDM include double-walled or double-bottom ASTs that can be monitored and release prevention barriers installed under the AST that are compatible with and sufficiently impervious to the liquid being stored. Release prevention barriers must be able to divert leaks to a point where they can be easily detected, such as along the perimeter of the tank. Steel and concrete are common examples of release prevention barriers.

SP001 Inspection Frequency		
Tank Capacity (gallons)	**Has Spill Control and CRDM**	**Has Spill Control but no CRDM**
660 - 1,100	M; A (no formal periodic inspections)	M; A (no formal periodic inspections)
1,101 – 5,000	M; A (no formal periodic inspections)	M; A; E(10); L(10)

5,001 – 30,000	M; A; E(20)	M; A; E(10); I(20) or M; A; E(5); L(10)
30,001 – 39,999	M; A; E(20)	M; A; E(5); L(5); I(15)
M = Monthly Inspection; **A** = Annual Inspection; **E** = External Inspection **L** = Leak Test; **I** = Internal Inspection; (#) = Inspection interval (in years) *Example*: E(5) indicates a formal external inspection every 5 years		

Moving ASTs

If an **AST**[1] is moved/relocated on the same property or from one property to another, it must be closed and reinstalled, with all associated notifications.

[1] All aboveground storage tanks at a facility, all the connected piping and ancillary equipment, all loading facilities, and all containment systems, if applicable

UST Operation

Click on the arrows below for information about periodic requirements that should be completed to operate your tank system in compliance.

Monthly

Release Detection

Monthly release detection is required for all regulated tanks. Common methods include interstitial monitoring, ATG (automatic tank gauge) testing and SIR (statistical inventory reconciliation). Tank owners/operators must obtain at least one passing test result for each tank every month.

The following requirements apply for each of the common release detection methods.

- Interstitial monitoring
  - Need a documented “normal” sensor status report for each tank every month or a written log of monthly observations of the interstice
  - Monthly interstitial monitoring may be used in place of annual line testing (if product piping is double-walled)
- ATG
  - Need a documented passing tank test for each tank every month
  - For tanks with low fuel levels: obtain monthly passing tests by maintaining adequate fuel volume or by upgrading to continuous statistical leak detection
  - For ATG systems that are capable of conducting monthly product line tests at a leak rate of 0.2

All UST systems installed during and after 2008 *must* use interstitial monitoring as the primary release detection method

    - gph (gallons per hour): you may use these tests in place of annual line testing at 0.1 gph as long as the results clearly indicate "line test" versus "tank test"
- SIR
    - Data must be submitted to a certified SIR vendor as soon as possible after the end of each month to ensure you will receive your SIR report no later than 20 days after the end of the month
    - Inconclusive or failed SIR results that are not overturned by the third-party SIR vendor within 24 hours of receiving the report from the vendor must be reported to OPS as a suspected release
    - A tank owner may choose to avoid SIR due to delayed release discovery and the ongoing expense associated with an SIR vendor

USTs for Emergency Generators

Owners of existing USTs used solely for emergency generators must **begin performing release detection on the tank(s) and piping by January 1, 2020**. Owners of USTs installed after January 1, 2017, used solely for emergency generators must perform release detection as soon as they are put into use.

Monthly Inspections

The UST Monthly Compliance Inspection Checklist should be completed each month. Maintain these records for a minimum of 12 months and make them available for OPS review. The Class A or Class B Operator should conduct these inspections but can delegate this duty to a person familiar with the fueling system if necessary.

Tips for Monthly Inspections

- Print or log your monthly release detection results or send inventory results to the SIR vendor. Include lines unless you perform annual line testing at 0.1 gph.

- The Monthly Compliance Inspection is divided into five main parts, for which OPS has produced helpful videos to walk you through the requirements.

Spill Containment Bucket

Tank Interior

Vapor Recovery

Dispenser Hardware

OPS recommends opening dispenser cabinets during Monthly Compliance Inspections.

Leak Detection

- Any product leakage or seeping connections should be addressed immediately. If product has come in contact with soil or groundwater, the tank owner/operator is required to report a suspected release to the OPS Technical Assistance Line at (303) 318-8547.
- If your UST system has impressed current cathodic protection, the system must be operated and maintained to continuously provide corrosion protection to the metallic components. The impressed current cathodic protection system must be inspected every 60 days to ensure that it is operating correctly; however, OPS recommends that this inspection be

completed every 30 days. Rectifier readings will be required for the period specified in the Annual Compliance Package.

Annually

Release Detection

It is important to contact OPS immediately after failed or inconclusive tank system tests, and to work with your contractor to identify, repair, and retest. Don't forget to submit the passing results to OPS as part of your records request.

Annual line tightness testing is required for pressurized product piping that is not monitored monthly.

- Utilize your automatic tank gauge system for piping release detection. Ensure your ATG is programmed to test both the piping and the tanks.
- You must produce an annual passing 0.1 gph line test or have a tank system subcontractor perform a 0.1 gph line pressure test.

Annual leak detector testing is required for all pressurized product piping.

- Utilize your ATG system for leak detector testing.
- You must produce an annual passing 3.0 gph leak detector functionality test or have a tank system subcontractor perform a 3.0 gph leak detector functionality test.

USTs for Emergency Generators

Owners of existing USTs used solely for emergency generators must **begin performing release detection on the tank(s) and piping by January 1, 2020**. Owners of USTs installed after January 1, 2017, used solely for emergency generators must perform release detection as soon as they are put into use.

Release Detection Equipment Inspections

Tank systems rely on a variety of equipment to detect releases. From something as simple as a tank gauge stick to something as complicated as a positive shutdown containment sump sensor, it is critical that this equipment function properly.

Release detection equipment including automatic tank gauge (ATG) probes/floats, sump sensors, associated electronic control equipment and tank gauging devices must be inspected by January 1, 2020, and every year thereafter. The inspection must be performed in accordance with manufacturer's recommendations, a standard code of practice or another OPS-approved method. A common way to ensure your inspection is valid is to use the industry's primary code of practice - Petroleum Equipment Institute's RP1200.

For example, an inspection for a tank system that relies on an ATG for release detection should include the following steps, at a minimum:

1. ATG and other controllers
    a. Test alarm
    b. Verify system configuration
    c. Test battery backup
2. Probes and sensors
    a. Remove and inspect for residual buildup
    b. Ensure floats move freely
    c. Ensure shaft is not damaged

d. Ensure cables are free of kinks and breaks

e. Test alarm operability and communication with controller

This inspection will help ensure your release detection is being conducted properly and will help you discover a release quickly should one occur.

The record of this inspection must be kept for at least one year.

Annual Inspections

Annual testing and inspections should be conducted within 12 months of the previous test or inspection, regardless of when OPS requests these records.

An Annual Compliance Inspection is required for all UST systems. It is intended to help identify leaks and to monitor the condition of tanks, piping, secondary containment and equipment. This inspection is more thorough than, and is to be conducted in addition to, the monthly compliance inspections.

Tips for Annual Inspections

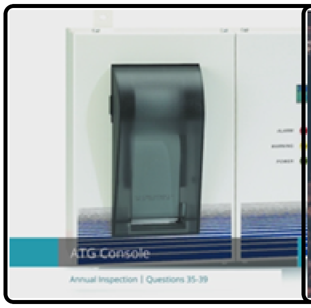
- A certified Class A or Class B Operator must conduct these inspections, provide the owner/operator with a copy and alert the owner/operator of any condition discovered during the inspection that may require follow-up actions. The inspection that an OPS inspector conducts at your facility is not a substitute for your annual inspection.
- A UST annual compliance inspection should be performed within 12 months of the previous one and will be required to be submitted to OPS for the period specified in the Annual Compliance Package.
- The annual compliance inspection is divided into 10 main parts, for which OPS has produced helpful videos to walk you through the inspection.

Fill Equipment and Spill and Overfill Protection

Tanks in Temporary Closure

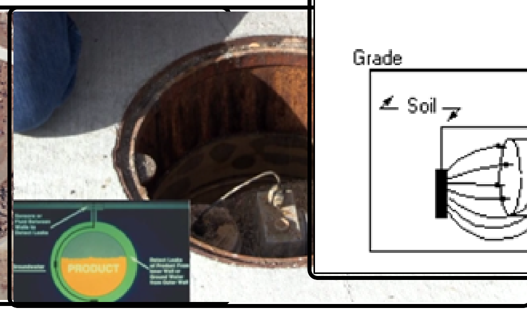
Vapor Recovery

Submersible Turbine Pump Sump

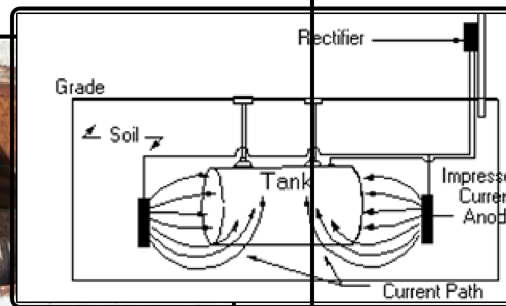


ATG Console

ATG Port



Tank Interstice

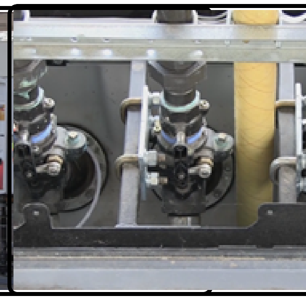


Cathodic Protection

Vent Piping

Unattended Fueling

Dispenser Hardware



Under-Dispenser

Emergency Equip-

Containment	ment

- If your leak detector fails, it must be replaced or repaired and a passing 3.0 gph functionality test must be documented. Submit the passing results to OPS as part of the annual records request.

Every Three Years

Contact OPS immediately after failed or inconclusive tank system tests, and work with your contractor to identify, repair, and retest. Remember to submit the retest results to OPS.

Spill Bucket Testing

The purpose of spill bucket testing is to ensure the spill bucket will hold small spills when the delivery hose is disconnected from the fill pipe. **All single-walled buckets, containers and basins used for spill protection on a UST must be tested by January 1, 2020, and every three years thereafter**. OPS provides a Secondary Containment Testing form that you can use to document the testing. OPS strongly recommends hiring a tank system subcontractor to perform your spill bucket testing.

Spill bucket testing must be performed in accordance with manufacturer's recommendations, a standard code of practice or another OPS-approved method. The most common methods for testing include hydrostatic (water level) testing and vacuum testing. A good way to ensure your test is valid is to use the industry's primary code of practice - Petroleum Equipment Institute's RP1200.

Hydrotesting is relatively easy to perform, but management of the water following the test can be challenging. The test water can be reused for similar testing at other sites. However, once the test water is no longer useful, it must be collected and disposed of at a permitted treatment facility or discharged under a permit from the Colorado Department of Public Health and Environment. It is illegal to dispose of test water to the ground surface, into storm drains or into the sanitary sewer system without proper permitting.

Drain valves found at the bottom of spill buckets are common sources of failure. It is important to ensure the drain valve is properly closed and seated prior to performing the test and during operation of the tank system.

Instead of performing the three-year hydrostatic or vacuum tests described above, owners of double-walled spill buckets can choose to check and document the interstitial gauge on a monthly basis, as follows:

- For double-walled equipment installed before January 1, 2017, a tightness test of the interstitial space must be conducted per manufacturer's instructions (most likely vacuum testing) by January 1, 2020. After this initial test, monthly interstitial observations will be accepted as an alternative to testing every three years.

- For double-walled equipment installed after January 1, 2017, a tightness test of the interstitial space must be conducted at installation per manufacturer's instructions (most likely vacuum testing performed before the equipment is buried and then again after concrete has been poured). After these initial installation tests, monthly interstitial observations will be accepted as an alternative to testing every three years. As a reminder, tightness testing must be performed again within 30 calendar days of one year thereafter, as has been required by regulation since August 1, 2008.

Additionally, the primary (or inner) bucket of double-walled spill buckets can be repaired or replaced without breaking concrete, making this a cost-effective option if replacement of your existing buckets is necessary. These types of spill buckets are a bit more expensive to install, but they can reduce testing and repair costs in the future.

Records of spill bucket testing need to be kept for three years.

Please use the UST Minor Equipment Repair/Replacement Notification form to notify OPS of spill bucket replacements.

Secondary Containment Testing

USTs and piping installed after August 1, 2008, are required to have secondary containment and use interstitial monitoring as the tank and piping release detection method. Secondary containment is meant to help prevent fuel releases from impacting the environment, so it is important to ensure the containment devices are liquid-tight.

OPS has required secondary containment testing at the time of installation and approximately one year thereafter since 2008. **Containment sumps used for piping interstitial monitoring must be tested by January 1, 2020, and every three years thereafter**. If you use interstitial monitoring for your piping release detection (which includes all piping installed after August 1, 2008), you need to have the containment sumps (under dispenser containment, submersible turbine pump containment and any piping transition sumps) tested. This requirement also applies to underground piping systems connected to aboveground storage tanks if interstitial monitoring is used for piping release detection.

Secondary containment must be performed in accordance with manufacturer's recommendations, a standard code of practice or another OPS-approved method. The most common method for testing is hydrostatic (water level) testing. A good way to ensure your test is valid is to use the industry's primary code of practice - Petroleum Equipment Institute's RP1200. The hydrotest procedure in RP1200 requires filling containment sumps to a level above all piping and conduit penetrations. **However, if the containment sump is equipped with a liquid level sensor (mounted below the penetration points) that automatically activates a shutdown of the UST system, OPS will allow the sump to be filled up to the level of the sump sensor during the three-year test**.

Hydrotesting is relatively easy to perform, but management of the water following the test can be challenging. The test water can be reused for similar testing at other sites; however, once the test water is no longer useful, it must be collected and disposed of at a permitted treatment facility or discharged under a permit from the Colorado Department of Public Health and Environment. It is illegal to dispose of test water to the ground surface, into storm drains or into the sanitary sewer system without proper permitting.

Double-walled containment sumps with interstitial monitoring between the walls can be checked monthly via their interstitial gauges and are not required to meet the three-year testing requirement. These types of containment sumps are more expensive to install, but they can reduce testing and repair costs in the future.

Please use the Secondary Containment Testing Form to document the test.

Records of secondary containment testing need to be kept for three years.

Additionally, though not a requirement, OPS strongly recommends testing the secondary piping while you're performing this containment sump testing. Given that the containment sumps need to be hydraulically isolated from the secondary piping for testing, it is relatively easy to also test the secondary piping at that time.

Double-walled containment sumps with interstitial monitoring between the walls can be checked monthly via their interstitial gauges and are not required to meet the three-year testing requirement. These types of containment sumps are more expensive to install but can reduce testing and repair costs in the future.

Fuel within the secondary containment device is not considered a suspected release unless the liquid level is at or above containment wall penetrations. The bottom seal of a submersible turbine pump containment is considered a penetration, so fuel above that seal would be a suspected release. Tank owners/operators must report suspected releases to OPS at 303-318-8547 within 24 hours of discovery.

Please use the Secondary Containment Testing Form to document the test. As with other three-year requirements, records of secondary containment testing need to be kept for three years.

Overfill Prevention Equipment Inspections

All underground storage tanks (USTs) that receive deliveries that are in excess of 25 gallons must have an overfill prevention device. These devices commonly include drop tube valves, vent line restrictors (ball floats) and overfill alarms. The purpose of these devices is to shut off or slow the delivery of product into the UST to avoid overfilling.

Devices used for overfill prevention on a UST must be inspected by January 1, 2020, and every three years thereafter. The inspection must be performed in accordance with manufacturer's recommendations, a standard code of practice or another OPS-approved method. A common way to ensure your inspection is valid is to use the industry's primary code of practice - Petroleum Equipment Institute's RP1200.

Overfill prevention devices must typically be removed to perform this inspection. The inspection should verify the levels, orientation, condition and proper operation of the device. During reinstallation, drop tube valves must be oriented properly so the float doesn't contact tank walls.

Problems with overfill prevention devices can occur due to corrosion, float or valve damage or improper installation. Removing the devices for inspection can be quite challenging due to corrosion or access issues. OPS strongly recommends hiring a tank system subcontractor to perform these inspections.

As with other three-year requirements, records of this inspection need to be kept for three years.

Cathodic Protection Testing

Two methods of corrosion protection - galvanic and impressed current - must be tested by a qualified cathodic protection tester, at least every three years, to ensure adequate protection of all metallic tank system components in contact with soil or water. Test reports of passing or failing results for the period specified are required. These test reports shall include the name of the facility, OPS Facility ID, and the facility's physical address. The test reports shall also include a concise narrative explaining the testing process used, the test results, and must also include a listing of the tanks system components being protected. A site aerial map with a north arrow, map scale, and a map key must also be included.

Suction Piping Testing

Conduct a line tightness test on UST systems with underground suction piping at least once every three years. Safe or European suction piping does not require tightness testing if it meets all of the following criteria:

- Operates at less than atmospheric pressure
- Sloped so that product drains back into the storage tank
- Includes only one check valve in each suction line that is located directly below and as close as practical to the suction pump

Upgrades to Existing Tank Systems

The need to modify or add to your petroleum storage tank system may arise at any time, and can be motivated by economic, compatibility, or regular maintenance issues. OPS is determined to work with you to expedite the permitting or notification process while ensuring we all abide by the applicable state and federal regulations. We provide two methods by which applicants can notify us of their system's changes.

If you are installing new or used regulated storage tanks, adding new system components that didn't exist before, adding secondary containment for piping interstitial monitoring, replacing or relocating underground or aboveground piping, or installing a tank within a tank, it is necessary to complete our Installation/Upgrade Permit Application in order to request a permit for that work. OPS will review the application, ask any necessary questions in order to understand the proposed changes, and issue a permit once the application is acceptable. Following permit issuance, it is important to keep OPS informed of the project's progress so we can schedule installation and startup inspections. These inspections help ensure a high quality and compliant system installation or upgrade.

On the other hand, our Minor Equipment Notification covers equipment repairs or replacements for which permitting and notice ahead of time are not required by OPS:

- Spill bucket replacement
- Automatic tank gauge installation or replacement
- Dispenser replacement if the concrete dispenser island is unmodified and no work at or below the shear valve is done. You must notify OPS using our Retail Motor Fuel Calibration Report within seven days after installing a

new or remanufactured dispenser or fuel meter, and that device must be proved and sealed as correct by a Registered Service Agency.

- Repairs to containment sump boots or cathodic protection systems

This Minor Equipment Notification utilizes a simpler form and applicants are not required to pay a fee. Further, this form can be submitted to OPS within seven days after the work is completed, allowing you to move quickly toward resolving the replacement or repair.

Transfer of Ownership

If petroleum storage tank ownership has changed, notify OPS within 30 days of the change or transfer of tank ownership by submitting either the AST or the UST Transfer of Ownership form to us at cdle_oil_inspection@state.co.us. It is important that OPS receives the Transfer of Ownership documentation in a timely manner to ensure compliance requirements are communicated with the current owner in a timely manner.

Only the new owner is required to notify OPS of the change in ownership; however, the transfer of ownership documentation can be completed by either the new owner *or* the former owner.

AST and UST Transfer of Ownership Form Examples

Click on the images below to view examples of completed transfer of ownership forms.

AST	UST

olorado Department of Labo
ivision of Oil and Public Safe
3 17th Street, Suite 500
enver, CO 80202-3610

ER OF OWNER

wns an Aboveground Storage T
(OPS) via
If you have any questions co

or Transfer: 11/23/15

Retail ☐ Bulk Plant
Other:
lity: American Aviation
USA Aviation
ge Orr Rd & Cessna Dr

erator Information

ne: Fly Straight LLC
Smith
17th St.

deral Government ☐ Stat
and within an Indian Reservatio

ned by a Native American, Nation
ibe or Nation where the ASTs are

ne: Circular Logic Inc.
a Jones
5 West Center Avenue

espondence Contact Inform

elf-Insurance ☑ Commerci
etter of Credit ☐ Bond Ratin
Other:

elease Detection & Release

Tank Release Detection Method	D
11: Monthly Visual Inspection	L2: Dou
11: Monthly Visual Inspection	L2: Dou

If the new owner is co

Colorado Department of Labor and Employment
Division of Oil and Public Safety – Compliance Section
633 17th Street, Suite 500
Denver, CO 80202-3610

Phone: 303-318-8525
Fax: 303-318-8488
Email : cdle_oil_inspection@st
Web: www.colorado.gov/ops

Underground Storage Tank
Transfer of Ownership or Change in Operatio

(Revised 5/14/15)

Any person who owns or operates an underground storage tank (UST) system must complete this form and submit it to the D
Safety via email, fax or postal mail within 30 days of the change or transfer.

Date of Ownership Transfer or Change in Operations: 11/16/15
Without this date, the form is considered invalid.

Facility Information

Facility Type:	☑ Retail ☐ Bulk Plant ☐ Commercial/Industrial ☐ Airport ☐ Federal ☐ State G					
Former Name of Facility:	New West Conoco			OPS Facility I.D.		
New Name of Facility (if name has changed):	Renegade Conoco		# of USTs:	3	Phon	
Facility Address:	666 Dire Straits Rd.	City:	Monument	County:	El Pa	

Former Owner/Operator Information

☐ No Former Owner Information

Owner/Operator Name:	New West Conoco LLC	Phone #:	614-555-1212		
Contact Name:	Rory Calhoun	Email Address:	roryc@newwest.com		
Mailing Address:	PO Box 1492	City:	Columbus	State:	OH

New Owner/Operator Information

Owner Type:	☐ Individual	☐ Federal Government	☐ State Gov
	☑ Corporation, Partnership or LLC	☐ Local Government or Municipality	☐ Native Ar
Purchase Type:	☑ Purchased property and business	☐ Purchased business only (including tanks)	☐ New Ope

Company Name (Example: XYZ Corp):	Westeros Enterprises LLC	Phone #:	719-555-1212	Cell Phone	
Contact Name:	Jon Snow	E-mail Address:	snowman@westeros.com		
Mailing Address:	1234 Martin Way	City:	Colorado Springs	State:	CO

New Primary Correspondence Contact Information

☑ Same As Owner Information

Contact Name:		Phone #:		Cell Phon	
Company Name (if different from above):		Email Address:			
Mailing Address:		City:		State:	

A/B Operator Information

Submit a copy of the training certificate with this form.

A/B Operator Name:	Tyrion Lannister		Phone #:	719-555-1212			
Email Address:	shortguy@westeros.com		Operator Type:	☑ A Operator and/or			
Mailing Address:	1234 Martin Way		City:	Colorado Springs	State:	CO	
Training Company:	Oil AB Training Inc.	Certification #:	123456	Date Trained:	1/15/10	OPS	

Financial Responsibility Information

Insurance Type:	☑ Self-Insurance	☐ Commercial Insurance	☐ Risk Retention Group	☐ Local Government Financial T
	☐ Letter of Credit	☐ Bond Rating Test	☐ State Fund	☐ Trust Fund

Owner/Operator Certification

If the new owner is completing this form, it will be considered a Transfer of Ownership.
I certify that I am familiar with the above information, and I believe that this information is true, accurate an

Printed Name:	Jon Snow	Title:	CEO	Owner Type:	

Tips for Completing the Transfer of Ownership form

- The facility name listed on the form should match the name identified on the signage at the facility building.
- Identify the correct date of ownership change.
- Identify the correct ownership type from these six options:
  - Individual
  - Corporate/Commercial
  - Federal Government
  - State Government
  - Local/Municipal Government
  - Native American Nation/Tribe
- Complete the A/B Operator information if your acquisition includes USTs and submit a copy of the A/B Operator's training certificate to OPS within 30 days of the Transfer of Ownership.

After acquiring a storage tank system, you may have questions about its operation, what rules apply and what to expect from OPS. Request a visit if you would like to meet with an OPS representative to discuss your site.

Tank Closure

There are a number of reasons why owners/operators may need to stop using their tanks, either temporarily or permanently. OPS allows three types of closure: seasonal, temporary and permanent.

Closure of a tank system can be a complicated and dangerous task for an owner/operator. **OPS highly advises the use of qualified tank removal contractors and environmental consultants.**

It is important for the owner/operator and the consultant to have a plan in place prior to beginning closure activities. The economic issues, disposal facilities, additional equipment needed and feasibility of emergency response must be considered prior to starting closure activities to effectively abate contamination to reduce risk of exposure.

OPS considers tanks to be currently in use unless seasonal, temporary or permanent closure requirements have been completed.

Tank Status	Description
Currently in use	More than one inch of product in tank.
Seasonal closure	Less than one inch of product in tank and unused for up to six consecutive months each year.
Temporary closure	Less than one inch of product in tank.
Permanent closure	All liquids and sludges are removed from tank system, and it is never used again to store regulated substances.

More information about the requirements for each closure type are described below.

Seasonal Closure

Owners/operators who operate a seasonal business are required to notify OPS prior to the start of the first seasonal operation. The notice of seasonal operation can be emailed to us at cdle_oil_inspection@state.co.us.

Seasonal closure criteria

- Facilities may not be placed in seasonal closure for longer than six months at a time.
- The owner/operator must provide documentation related to tank pump-down at the end of the season.
- The tank must be emptied and additional release detection is not required as long as the tank system is empty, which occurs when all materials have been removed using commonly-employed practices such that no more than one inch of residue, or 0.3% by weight of the total capacity of the tank system, remains in the system.
- The owner/operator must maintain certified Class A, B and C Operators for USTs.
- When a tank system is closed for the season, the owner/operator must continue operation and maintenance of corrosion protection. This includes three-year corrosion protection system testing and recording 60-day rectifier readings, if applicable.
- The annual registration fee ($35 per tank) still applies.

At the end of the seasonal period, the owner/operator must put the tank system back into service, place it into proper temporary closure or permanently close it.

Temporary Closure

If the tank system is not going to be operated and the owner isn't sure when operations will begin, or if the tank system does not contain enough fuel to perform release detection, the owner may put the tank system into Temporary

Closure. OPS may allow a temporary closure of tank systems for a period of up to 12 months. After the 12-month temporary closure period has elapsed, the owner/operator must put the tank system back into service, permanently close it or request an extension.

For a tank to be properly placed into temporary closure the following criteria must be met:

UST

- Notify OPS in writing at least 10 calendar days prior to placing a tank system into temporary closure.
- Submit 12 months of release detection and corrosion protection records for lines and tanks *or* a precision tightness test on tanks and a limited site assessment.
- Remove the regulated substance from the tank such that no more than one inch remains and provide documentation[1] to OPS.
- Vent lines must be left open and functioning.
- If the temporary closure period is three months or more, all pumps, manways, ancillary equipment and lines (other than vent lines) must be capped and secured, unless an alternate schedule is approved.
- Because the tanks must be emptied, release detection is not required.
- The owner/operator must maintain certified Class A, B and C Operators.
- The owner/operator must continue operation and maintenance of corrosion protection. This includes three-year corrosion protection system testing and recording 60-day rectifier readings, if applicable.
- The owner/operator must complete an Annual Compliance Inspection.
- The annual registration fee ($35 per tank) still applies.

AST

[1] waste manifest, bills of lading, invoices, etc.

- Notify OPS in writing at least 10 calendar days prior to placing a tank system into temporary closure.
- Submit 12 months of monthly visual inspections, inventory control, ullage records, piping release detection records and corrosion protection testing (if applicable) for tanks and piping *or* conduct a tightness test of the tanks and underground piping and complete a limited site assessment.
- Remove the regulated substance from the tank such that no more than one inch remains and provide documentation[1] to OPS.
- The AST must be safeguarded against trespassing by means of locked gates, fences, etc.
- Vent lines must be left open and functioning.
- If the temporary closure period is three months or more, all pumps, manways, ancillary equipment and lines (other than vent lines) must be capped and secured, unless an alternate schedule is approved.
- Because the tanks must be emptied, release detection is not required.
- The owner/operator must continue operation and maintenance of corrosion protection. This includes three-year corrosion protection system testing and recording 60-day rectifier readings, if applicable.
- The owner/operator must complete an Annual Visual Inspection.
- The $35 per tank annual registration fee still applies.

Temporary Closure Extension

After 12 months of temporary closure, the owner/operator must put the tank system back into service, permanently close it or request an extension to the temporary closure period. If an extension is desired, the owner/operator must submit an extension request and site assessment results in writing. OPS will

[1] waste manifest, bills of lading, invoices, etc.

determine and communicate the new temporary closure end date based upon equipment risk, operational compliance and environmental impacts.

OPS requires owners to permanently close their tanks or put them back into service once they've reached the end of their temporary closure extensions.

Conducting a Site Assessment for UST Temporary Closure

These site assessment requirements must be followed if you don't have release detection records for temporary closure or if you are extending temporary closure.

In Colorado, it is required by law to have utilities marked prior to any subsurface work. Call Colorado 811 at least 48 hours prior to any activities.

Soil Sampling to Meet the Site Assessment Requirement

- The excavation or soil boring must be located no further than five feet from the edge of the tank and must be advanced to a depth of two times the projected vertical distance from the ground surface to the bottom of the tank basin. For example, if the native soil below a tank is estimated to be 12 feet below the ground surface and the sampling surface location is five feet from the end of the tank, the minimum depth of the investigation must be 24 feet.
- If a site assessment is being conducted for one UST, two sampling locations are required - one at each end of the tank or one on each side of the tank.
- If a site assessment is being conducted for multiple tanks, a minimum of four boring locations is required: one location at each corner of the tank basin or one location near the middle of each side of the tank basin.
- A sample must be collected when groundwater is encountered during any site assessment.

Groundwater Sampling to Meet the Site Assessment Requirement

- When shallow groundwater is present and any portion of the tank system is submerged, groundwater sampling is required. Groundwater samples collected from tank basin monitoring points are acceptable.
- One strategically placed groundwater sample collected from an area immediately downgradient of the tank area will meet the site assessment requirement. The inferred groundwater flow direction must be verified by local groundwater flow information or projected using fundamental hydrodynamic principles.

Conducting a Site Assessment for AST Temporary Closure

These site assessment requirements must be followed if you don't have release detection records for temporary closure or if you are extending temporary closure.

Each AST installation is different and will require that the owner/operator submit pictures of the tank and surrounding area with the request to apply for temporary closure or extend temporary closure when release detection records are not available.

The pictures, which will allow OPS and the owner/operator to develop a site assessment plan to meet the temporary closure requirement, must include the following, at a minimum:

- A panoramic view of the tanks and surrounding area
- The inside of the containment structure and containment drain outfall areas (if present)
- The fuel loading and dispensing areas

If further site assessment is required, owners/operators should utilize the AST closure requirements below to develop the temporary closure site assessment.

Sampling to Meet the Site Assessment Requirement

- Soil sampling will depend on the type of tank system.
- Groundwater sampling is an accepted procedure to meet the site assessment requirement.
- One strategically-placed groundwater sample collected from an area immediately downgradient of the tank area will fulfill the site assessment requirement. The inferred groundwater flow direction must be verified by local groundwater flow information or projected using fundamental hydrodynamic principles.

Back In Service

UST

Owners/operators should notify OPS in writing no more than 30 calendar days prior to placing a UST back in service, and at that time they should also submit corrosion protection records (if applicable) for the period of temporary closure and documentation of passing tightness tests (including ullage) for the tanks conducted within the past 30 calendar days. Owners/operators should obtain passing line and leak detector tests immediately following the introduction of fuel into the lines and submit documentation of testing to OPS within 10 calendar days.

AST

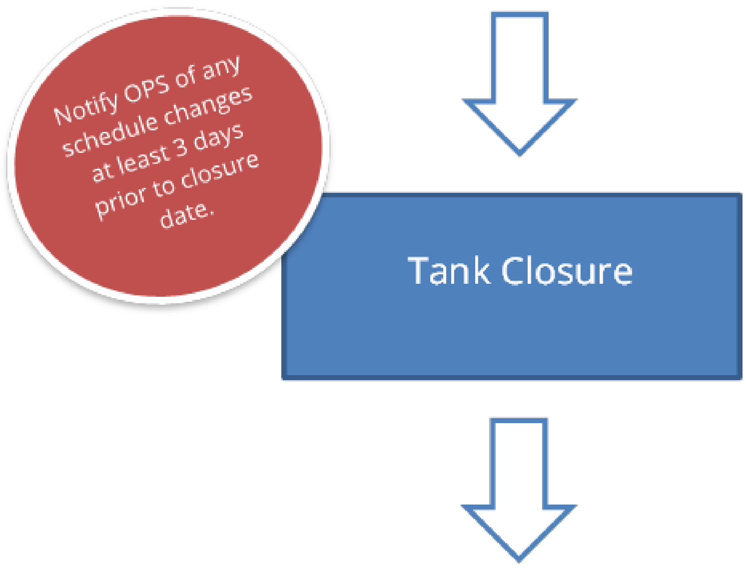
Owners/operators shall notify OPS in writing no more than 30 calendar days prior to placing an AST back in service, and at that time they should also submit corrosion protection records (if applicable) for the period of temporary closure and documentation of passing tightness tests for the AST that were conducted within the past 30 calendar days. Owners/operators should obtain passing tightness tests for underground lines immediately upon introduction of fuel into the lines and submit documentation of testing to OPS within 10 calendar days.

Permanent Closure

Once owners/operators are ready to permanently close their tank systems, all liquids and sludges must be removed and the following process must be followed.

10+ Days **Before** Closure Activity

- Submit a Notice of Intent (NOI) Form to OPS prior to beginning closure activities. The form should identify the proposed closure date and time and include site photos.
- Fire departments and other regulatory agencies must be notified and all applicable regulations followed. OPS will not allow the closure of any tank that is not in compliance with all regulatory agencies.



30 Days **After** Closure Activity*

Submit Tank Closure Report to OPS which includes:

- Closure Inspection Form
- Environmental Site Assessment (ESA):
  - figure(s) depicting sampling locations and all fuel system components,
  - organic vapor meter (OVM) table including date, depth, and OVM readings,
  - pictures,
  - laboratory analytical report(s), and
  - a narrative explaining the closure process and ESA results. If a No Further Action (NFA) letter is requested the narrative must reflect this.

*If laboratory data indicates a detection of regulated substance in the environment a confirmed release must be reported to OPS at (303) 318-8547 within 24-hours of receiving analytical data. If there is a confirmed release for the closure a Site Characterization Report (SCR) is due within 180-days of the sampling date and a Tank Closure Report is not required. All data from closure activities is required to be in the SCR.

The completed report should then be sent via email to cdle_oil_inspection@state.co.us or mailed to the address listed on the form.

UST Closure Sampling Requirements

Owners/operators can choose one of three ways to permanently close their tanks: closure by removal, closure in place or change in service.

Closure by Removal	Closure in Place	Change in Service to an Unregulated Substance
• Contact the local fire department. • Ensure site security during closure activ-	• Contact the local fire department to determine whether closure in place is	• Empty and clean the tanks. • All product piping must be emptied

Closure by Removal	Closure in Place	Change in Service to an Unregulated Substance
ities. • Empty and clean the tanks. • Secure all tank openings, except one vent line, at a minimum of eight feet above the top of the tank. • Confirm the tank internal atmosphere is vapor-free prior to moving. • Secure the tanks on a transport device and replace the vent with one ¼-inch vent opening. All applicable transportation laws and regulations must be followed, including those of the US Department of Transportation. • All product piping must be emptied, cleaned and capped	permissible. • Empty and clean the tanks. • All product piping must be emptied, cleaned and capped or removed. Piping must be disconnected from the tanks. OPS prefers that product piping be removed at the time of closure. • Confirm that the tank internal atmosphere is vapor-free. • Tanks must be filled with an inert solid material, such as sand or flow fill. • Secure all tank openings. • Keep vents active. • Perform envir-	and cleaned or removed. OPS prefers that product piping be removed at time of closure. • Confirm that the tank internal atmosphere is vapor free. • Perform an environmental site assessment.

Closure by Removal	Closure in Place	Change in Service to an Unregulated Substance
or removed. OPS prefers that product piping be removed at the time of closure. • Dispose of the tanks properly. • Perform an environmental site assessment.	onmental site assessment. • Perform an environmental site assessment.	

Site Assessment Requirements

Integral parts of a closure site assessment include:

In Colorado, it is required by law to have utilities marked prior to any subsurface work. Call Colorado 811 at least 48 hours prior to any activities.

- A visual site inspection to identify the presence of petroleum staining
- Soil screening with an organic vapor analysis instrument
- Soil sample collection to define the extent of the impacts in a vertical and horizontal direction
- Laboratory analysis

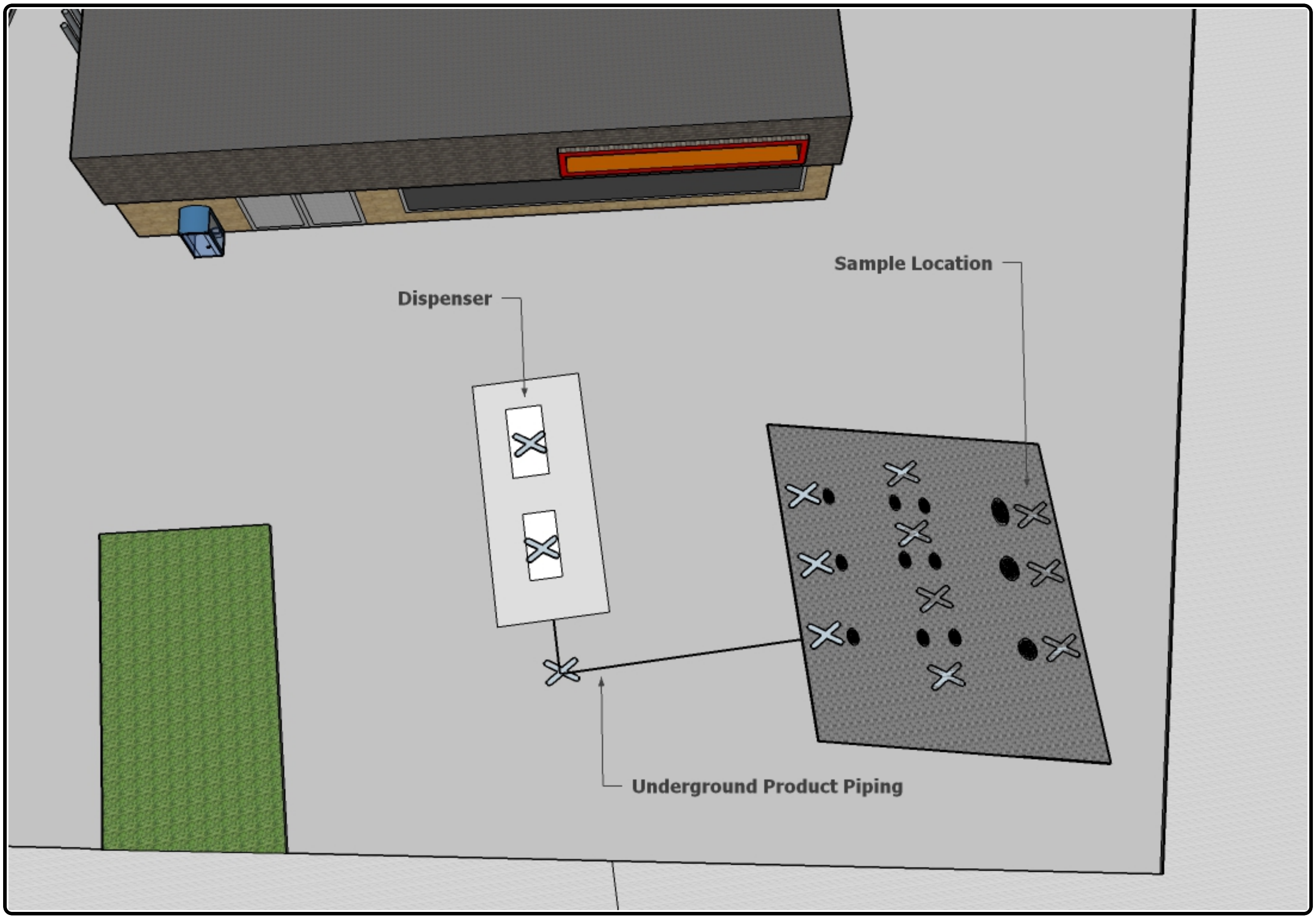
Tank Samples

A suspected or confirmed release discovered during closure activities must be reported to the OPS Technical Assistance Line (303) 318-8547 within 24 hours of the discovery.

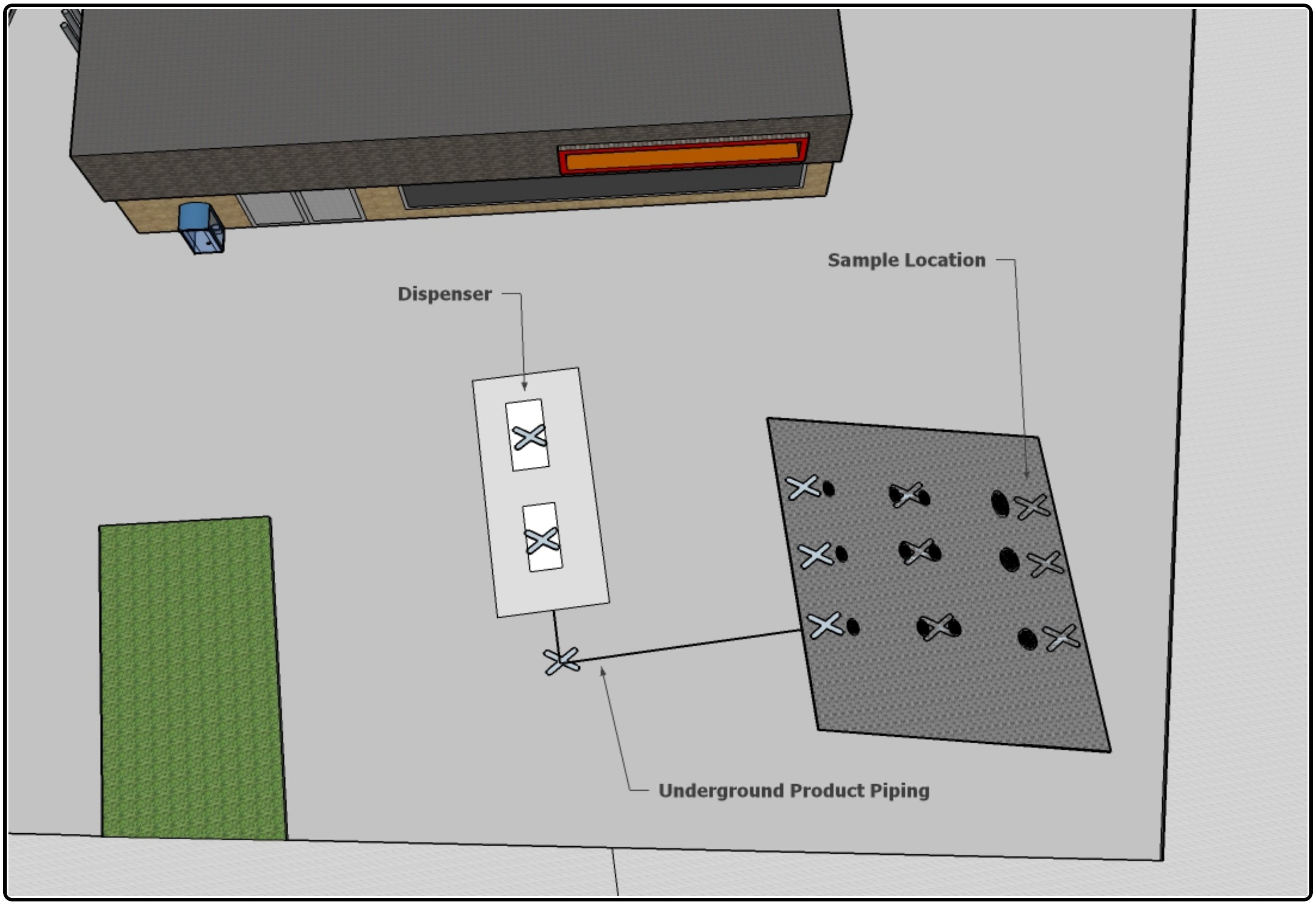
For tanks that are removed, native soil samples are required to be taken from beneath each end of the tank, and for tanks greater than 1,000 gallons, samples are also required from below the center of the tank.

If shallow groundwater is encountered during removal, a sample must be collected and analyzed in a laboratory. Native soil samples should then be collected directly above the water table from native soil on each sidewall of the excavation.

For tanks that are left in place (closed in place or change in service), soil samples must be collected from locations and depths most likely to identify contamination (e.g., if the native soil below a tank is estimated to be 12 feet below the ground surface and the sampling surface location is five feet from the end of the tank, the minimum depth of the investigation must be 24 feet). At a minimum, samples must be collected from each end of the tank and from each side. If groundwater is encountered, it must be sampled, and soil samples must be collected from above the groundwater table.



Sample locations for UST closure in place. Note that some of the sample locations are between the tanks.



Sample locations for UST closure by removal

Piping Samples

Underground piping must be sampled at all points where a change in product flow direction occurs within the piping (turns).

If piping is removed, samples must be obtained from native soil directly below the piping.

If piping is left in place, a soil sample boring must be advanced within three feet of the piping and screened for the presence of a release to a minimum of 10 feet below ground surface.

Dispenser Samples

One sample is required directly beneath each dispenser from native soil.

Assessment Results

If the assessment shows that contaminant concentrations are below the current State standards, the owner/operator can request that a No Further Action (NFA) status be given to the permanently closed UST in the closure report. If the assessment shows that contaminant concentrations are above the current State standards, the release must be assessed.

AST Closure Sampling Requirements

Owners/operators can choose one of three ways to permanently close their tanks: closure by removal, closure in place or change in service.

Closure by Removal	Closure in Place	Change in Service to an Unregulated Substance
• Ensure site security during closure activities. • Empty and clean the tank. • All product piping must be emptied, cleaned and capped or removed. It is highly recommended that product piping is removed at the time of closure. • Secure all tank open-	• Contact the local fire department to determine whether closure in place is permissible. • Empty and clean the tank. • All product piping must be emptied, cleaned and capped or removed. Piping must be disconnected from the tank. It is highly recommended that	• Empty and clean the tank. • All product piping must be emptied, cleaned and capped or removed. It is highly recommended that product piping is removed at time of closure. • Confirm that the tank internal atmosphere is vapor-free.

Closure by Removal	Closure in Place	Change in Service to an Unregulated Substance
ings except one vent line. • Confirm that the internal tank atmosphere is vapor-free prior to moving. • Secure the tank on a transport device and replace the vent with one ¼-inch vent opening. All applicable transportation laws and regulations must be followed, including those of the US Department of Transportation. • Dispose of the tank properly. • Perform an environmental site assessment.	product piping is removed at the time of closure. • Secure all tank openings. • Keep vents active. • Confirm tank internal atmosphere is vapor-free. • To return an AST back to service containing a regulated substance, the tank would have to be inspected and re-certified per the tank manufacturer, and permitted through OPS. • Perform an environmental site assessment.	• To return an AST back to service containing a regulated substance, the tank would have to be inspected and re-certified per the tank manufacturer, and permitted through OPS. OPS will not allow a tank that has held an incompatible substance for that tank (e.g., water in a steel tank) to be brought back into service. • Perform an environmental site assessment.

Site Assessment Requirements

Integral parts of a closure site assessment include:

- A visual site inspection to identify the presence of petroleum staining
- Soil screening with an organic vapor analysis instrument
- Soil sample collection to define the extent of the impacts in a vertical and horizontal direction
- Laboratory analysis

Samples Required for All Sites

Sample Location	Required Sample
Product loading/unloading areas	One soil sample must be collected and analyzed from each rack and remote fill location.
Tank truck/vehicle fueling areas	One soil sample must be collected from beneath each tank truck/vehicle fueling area when surface cover is soil or gravel. Additionally, at least one soil sample must be collected beneath each product dispenser.
Containment drain port discharge area	One soil sample must be collected from beneath each soil or gravel covered discharge area.
Aboveground piping	Surficial soil must be visually screened and sampled when organic vapor is detected or petroleum soil staining is observed.
Underground piping	It is recommended that underground product piping be removed during tank closure. If the line is abandoned in place it must be emptied of product and capped on the ends. Underground piping must be sampled at all points where a change in product flow direction occurs within the piping (turns). If piping is removed, samples must be obtained from native soil directly below the piping. If piping is left in place, a soil sample

Sample Location	Required Sample
	boring must be advanced within 3 feet of the piping and screened for the presence of a release to a minimum of 10 feet below ground surface.

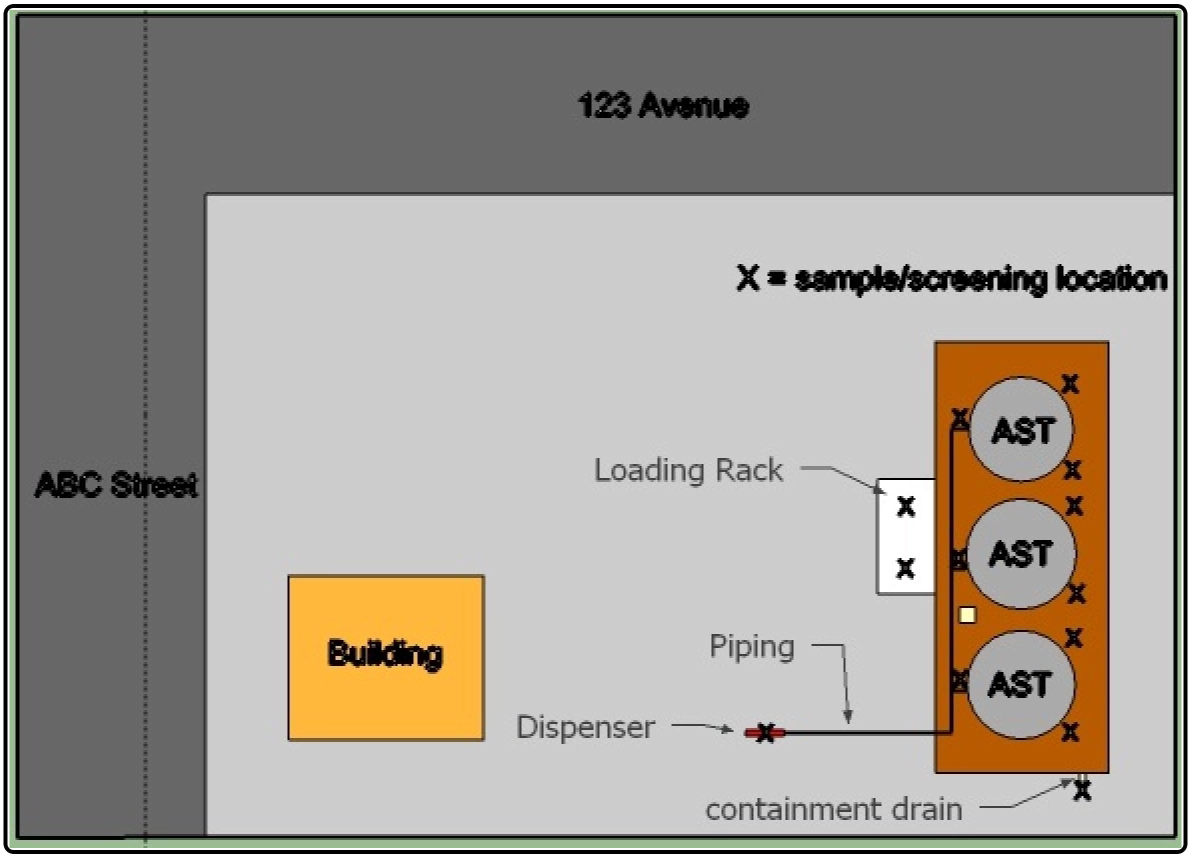
Visual Assessment

If all of the conditions below are true, contact OPS about potentially eliminating the need for tank-related sampling.

- ASTs are double-walled or are located within secondary containment
- All fill connections and dispensers are located on the top of the tank
- Complete monthly release detection records are available
- No visible staining is present

Sample Location for ASTs Located on Soil, Synthetic or Clay Liner Foundation

- The footprint of the tank must be visually inspected for soil staining and sampled if staining is present.
- If no staining is present, the soil foundation area must be screened in three equally-spaced locations around the tank perimeter to a minimum of three feet below ground surface.
- Special attention must be given to product transfer pumps and the areas where product enters or exits the tank. A minimum of one soil sample must be collected from a screened location that exhibits the highest detection of organic vapor or visually-identified soil staining.
- If organic vapor or stained soils are not encountered, soil samples from beneath product transfer pumps and areas where the product enters or exits the tank must be collected and analyzed in a laboratory.

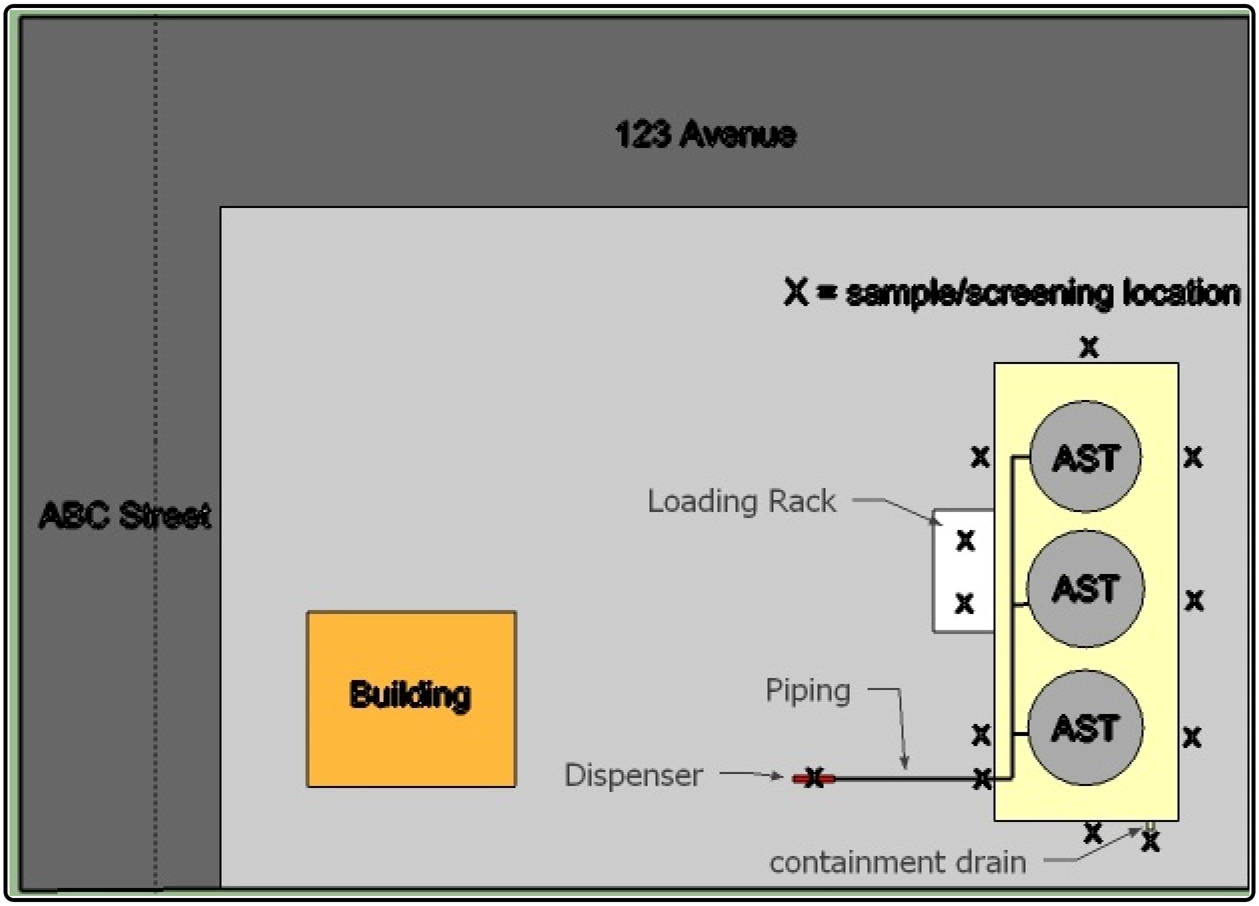


Sample location figure

Sample Location for ASTs Located on Concrete Slabs or Within Concrete or Similar Secondary Containment.

- Soil screening and sampling must take place adjacent to the AST foundation slab or containment structure. If staining is present, samples of the stained soils must be collected.
- If staining is present on a foundation slab or within a containment structure, soil screening/sampling must be conducted in the native soil immediately adjacent to the staining.
- If no staining is present, a sampling location adjacent to the center of each side or adjacent to the corners of a tank foundation slab or containment will be required.

- The structural integrity of the slab or containment must be evaluated and samples collected and analyzed beneath areas that have been compromised.



Sample location figure

Additional Resources

Best Industry Procedures for UST Removal

- American Petroleum Institute Recommended Practice 1604, *Removal and Disposal of Used Underground Petroleum Storage Tanks*
- American Petroleum Institute Publication 2015, *Cleaning Petroleum Storage Tanks*
- American Petroleum Institute Recommended Practice 1631, *Interior Lining of Underground Storage Tanks*
- The National Institute for Occupational Safety and Health *Criteria for a Recommended Standard…Working in Confined Space*
- New England Water Pollution Control Commission, *Tank Closure Without Tears: An Inspectors Safety Guide*

Best Industry Procedures for AST Removal

- American Petroleum Institute Publication 2015, *Cleaning Petroleum Storage Tanks*
- American Petroleum Institute Publication 2015A, *Lead Hazard Associated with Tank Entry*
- American Petroleum Institute Publication 2015B, *Cleaning Open Top and Floating Roof Tanks*
- The National Institute for Occupational Safety and Health *Criteria for a Recommended Standard…Working in Confined Space*
- New England Water Pollution Control Commission, *Tank Closure Without Tears: An Inspectors Safety Guide*

Introduction

An owner/operator of a regulated petroleum storage tank facility is responsible for assessing and remediating a petroleum release upon discovery. Typically, a Recognized Environmental Professional is contracted to assist an owner/operator to respond to petroleum releases. OPS utilizes a formal method of risk evaluation based on the American Society of Testing and Materials Standard E 1739-95. This approach to risk evaluation allows for multiple closure criteria, or tiers, to be applied to a petroleum release.

OPS has the following remediation[1] goals:

Reduce impact of petroleum releases to the environment and the public.	**Ensure releases are reported by owners/operators of regulated tank systems.**	**Ensure timely and appropriate cleanup of leaking petroleum storage tank systems.**	**Provide technica guidance on release response regulations, tools and new research**

The release response section of the guidance addresses the topics of release discovery, initial abatement, characterization, corrective actions and closure criteria. OPS will issue a No Further Action letter once it has been demonstrated that the petroleum release is considered to be low risk to human health and the environment.Petroleum release information will be archived in the OPS database and will indicate the appropriate closure criteria. A petroleum release may be reopened if exposure conditions change.

You can contact the Remediation Section with questions by calling (303) 318-8547 or emailing us at cdle_remediation@state.co.us.

[1]Reducing the environmental footprint of a petroleum release to soil, groundwater, surface water and air in order to be protective of human health and the environment.

Additional Resources

[Standard Guide for Risk-Based Corrective Action (RBCA) Applied at Petroleum Release Sites]

Emergency Response

Petroleum storage tanks have the potential to cause acute human health and environmental impacts that require the tank system owner/operator to take immediate action.

The information included below provides owners/operators of petroleum storage tank systems with guidance regarding how to:

- Identify and mitigate the immediate threat of fire, explosion, vapor and acute health hazards
- Identify and mitigate impacts to water supply wells, supply lines or surface intake
- Initiate containment and removal of petroleum on the ground surface or surface water body

Click on the arrows to learn more about each aspect of emergency response.

Emergency Response Actions for Petroleum Releases

The table below identifies emergency response conditions and associated actions.

Immediate Threat	Response Action
A petroleum surface spill is occurring that creates the risk of fire, explosion and vapor inhalation.	• Stop the release of product • Notify the local fire authority • Begin emergency response per the site action plan
Explosive levels or concentrations of vapors that could cause acute health effects are present in a residence or building.	• Notify the local fire authority • Evacuate occupants as directed by the fire authority • Begin emergency abatement meas-

Immediate Threat	Response Action
	ures
Explosive levels of vapors are present in a subsurface utility system.	• Notify the local fire authority • Evacuate occupants as directed by the fire authority • Begin emergency abatement measures
Petroleum product is present on surface water in utilities or in a sensitive environment.	• Prevent further petroleum product migration • Begin recovery measures • Restrict area access
A water supply well is impacted by a petroleum release.	• Notify users • Provide alternate water supply
Surface water, stormwater or groundwater which is impacted above action levels is discharging directly to a surface water body used for human drinking water or contact recreation, or a sensitive environment.	• Minimize the extent of the impact by containment measures • Implement habitat management to minimize exposures

Once emergency response actions have been completed, contact the appropriate regulatory agencies. Notify OPS of any reportable releases within 24 hours of discovery.

Regulatory Requirements

The Class C Operator must be trained by the Class A or Class B Operator to take action in response to emergencies. At least one Class C Operator must be present during operating hours at attended facilities.

In the event of an emergency, the Class C Operator must:

- Stop the release by locating and activating the emergency stop switch. If the release or spill is uncontrollable, call the fire department or 911.
- Notify the Class B or Class A operator and appropriate emergency responders, when necessary.
- Operate the fire extinguisher, if it is safe to do so.

Be Prepared

OPS recommends having a plan ready in the event of a spill or emergency situation. Tank owners/operators are encouraged to develop a site-specific action plan that identifies how to stop the release, establishes how a release will migrate from the various on-site sources and provides guidance to retard the migration of the released product and properly cleanup the spill. Storage tank facilities should also have spill response equipment and supplies on hand to be used if a release occurs.

Here are suggested items to include in your action plan.

- A list of **emergency contacts**
- A **site diagram** showing the petroleum dispensing system components, on-site monitoring wells and the potential flow path of a spill released from various locations within the system
- A **spill kit** that contains emergency supplies, including absorbent materials (granular, pads, pillows or socks), personal protective equipment, traffic cones and caution tape to control public access to a spill, waste disposal bags and an appropriate waste storage container
- An **evacuation plan** for on-site personnel and the general public

This action plan can be applied to spills or leaks of any quantity. Quick and decisive response action is important. Personnel must understand the elements of the plan and frequently review the procedures associated with responding to a spill. It is recommended that response action training drills become part of an owner's/operator's standard operating procedure.

Protection of human life and acute health requires a quick response when an uncontrolled release of petroleum products occurs. Responders should avoid direct contact with the spilled petroleum, and they should also avoid inhaling petroleum vapors. It may be necessary to remove people from the area and create an exclusion zone to keep bystanders away from the spilled product. Fire and explosion hazards are an immediate threat and ignition sources, such as running vehicle engines and smoking, must be restricted within the exclusion zone.

It is important to protect the environment and personal property. After stopping the leak or spill by activating the emergency stop switch, assess whether the spilled fuel can be controlled. For small spills, use absorbent materials to keep the fuel from spreading.

If the spill becomes uncontrollable, or if the fuel migrates off-site, contact emergency services by dialing 911 or an alternate emergency contact telephone number. If possible, stop the migration of spilled fuel from entering stormwater drainage systems, running off pavement onto soil or into a sensitive environment or on-site monitoring wells.

Additional Resources:

ASTSWMO Emergency Response Case Studies

Release Discovery and Reporting

Owners/operators of petroleum storage tank systems are responsible to identify, report and investigate **suspected**[1] and **confirmed**[2] releases from their system.

- **Suspected releases** are based on indirect evidence of a regulated substance outside the tank system, and will require a tank system test[3] or a site check[4].
- **Confirmed releases** are identified by direct evidence of a regulated substance outside of the tank system.

This information below provides examples of suspected and confirmed conditions that require immediate action with suggested actions to respond to those conditions. Release discovery and reporting is critical to protect public health, minimize environmental damage and reduce related cleanup efforts.

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[1] Indirect evidence of a release such as a failed line or tank tightness test, unusual operating conditions, water in the tanks if the tanks do not test liquid-tight, inventory loss identified by leak detection equipment, inconclusive or failed SIR results or fuel in secondary containment (in contact with penetration points) or in damaged spill buckets. Suspected releases must be addressed by a system test or site check.

[2] Direct evidence of regulated substance outside the tank system. Direct evidence includes detection of chemical compounds in soil or groundwater, observation of fuel outside the storage tank system, identification of contamination during tank system repairs, installation, replacement or other sub-pavement work, or the identification of regulated substance in soil, basements, utility lines or on surface water, in groundwater or in water wells. Confirmed releases include surface spills on or off pavement that are not cleaned up within 24 hours or are greater than 25 gallons.

[3] Test of tank system components, including any associated delivery piping, secondary containment or spill control component, to identify releases of regulated substances.

[4] samples must be collected from appropriate locations and depths in the vicinity of the suspected source(s) (i.e. tanks, lines, dispensers) to determine if a release to the environment has occurred

Actions Necessary within 24 hours of Release Discovery

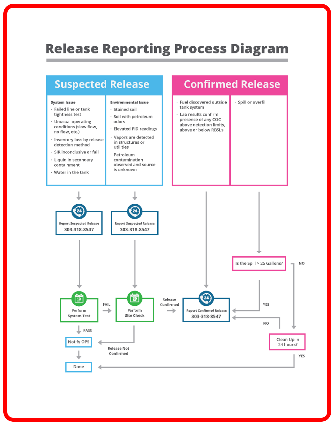
Take immediate action when a release is discovered in order to reduce the risk to human health and the environment, including the steps below.

- Stop the release.
- Visually inspect the area.
- Prevent fuel from spreading into storm drains or sewers where it may affect surface water (streams, lakes, etc.) or cause explosions.
- Eliminate or reduce fire, explosion or vapor hazards to the maximum extent possible and call 911.
- Call the OPS Technical Assistance Line at (303) 318-8547 to report a release.
  - If the release occurs outside of normal business hours, or if fuel enters storm drains or sewers, call the Colorado Department of Public Health and Environment release hotline at (877) 518-5608. Also call the OPS Technical Assistance Line at (303) 318-8547 and leave a message.
  - The following information is helpful when reporting a release.
    - Facility name, address and facility ID number, if known
    - Date the release was discovered
    - What happened (Including product type, amount of product released, cause of release and response actions)
    - Owner's contact information

Did you know that you may be eligible to receive reimbursement from the State to help with cleanup? Report releases to OPS within 24 hours of discovery to avoid reducing the amount of your potential reimbursement.

Release Reporting Process

Click on the image below to view the steps in the release reporting process.



Examples of Suspected Releases

ATG alarm or failure

Scenario: The alarm for the ATG (automatic tank gauge) system indicates a loss of product from your primary containment or a problem with the release detection system. The ATG system may need maintenance.

Action: Check to be sure the release detection is working properly and that there has not been a release. Contact your compliance contractor as soon as possible to see if a repair is needed. You must receive a passing result within 24 hours of the alarm.

Result: Notify OPS with the results of the investigation and repairs, if any. A site check must be completed within 30 calendar days of the release discovery if the results of the investigation suggest that a release has occurred.

SIR inconclusive or failure

Scenario: The SIR (statistical inventory reconciliation) vendor reports inconclusive SIR results that cannot be overturned within 24 hours, or the vendor reports failed SIR results for the previous month.

Action: Owner/operator notifies OPS of the failed SIR report and begins a system test that includes checking meter calibration, checking blend ratios and conducting pressurized tightness tests on tanks and lines.

Result: Notify OPS of the results of the system test[1]. If the tank and line tests fail, the owner/operator must perform a site check around the failing components of the system.

Regulated substance in secondary containment

Scenario: Liquid was found in areas such as the submersible turbine pump sump or under-dispenser containment of a dispenser above the pipe entry.

Action: Contact your compliance contractor to have the product pumped out. The secondary containment should then be hydrostatically tested before and after repairs are completed.

Result: Contact OPS with the results of the hydrostatic test. If there is a failed result, a site check will be necessary.

Spill bucket

Scenario: A regulated substance is found in contact with a damaged portion of the spill bucket or damage to the bottom of the spill bucket is observed.

Action: Remove all liquid from the spill bucket and conduct a hydrostatic or vacuum test. If the spill bucket shows evidence of cracks or any other signs of damage, complete the spill bucket assessment while replacing it.

Result: Notify OPS of the results of the system test. If the test fails, the owner/operator must perform a site check around the failing components of the system.

Failed line tightness test

Scenario: During a routine piping test, a product line has failed.

Action: A site check must be conducted within 30 calendar days. Repairs need to be done to the line and a pressurized line tightness test must be performed.

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[1]Test of tank system components, including any associated delivery piping, secondary containment or spill control component, to identify releases of regulated substances.

Results: Submit the site check results and the repair documents showing the passing line tightness test to OPS.

Stained soil, petroleum odors in soil or elevated photoionization detector measurements in soil

Scenario: While excavating, drilling or performing repairs to the tank system, stained soil or petroleum odors are observed, or the photoionization detector indicates elevated levels (> 50 ppm_V) of volatile organic compounds in soil.

Action: Contact OPS and perform a site check. See **Chemicals of Concern** for analytical requirements.

Result: Notify OPS of the results of the site check. If any detections are reported, you must report a confirmed release.

Vapors detected in a structure

Scenario: Petroleum vapors are impacting an adjacent building.

Action: Contact the fire department and OPS. Work with the fire department to evacuate the structure, if necessary, and perform a tank system test.

Result: Notify OPS of the system test results.

Examples of Confirmed Releases

Detection of Chemicals of Concern in samples analyzed in a laboratory

Scenario: Chemicals of concern are detected in soil or groundwater samples associated with a tank system.

Action: Report a confirmed released to OPS within 24 hours of receipt of the laboratory report.

Result: Begin assessment in anticipation of submitting the Site Characterization Report to OPS within 180 days of the release discovery.

Regulated substance discovered outside of the tank system

Scenario 1: During the removal of a UST system, shallow groundwater is encountered and regulated substance is noted to be present on groundwater in the UST pit.

Scenario 2: Product is dripping from a pump or under a dispenser with no secondary containment.

Scenario 3: During a site assessment, regulated substance is discovered from a regulated tank system.

Action: Report a confirmed released to OPS within 24 hours of discovery. Mitigation of LNAPL (light non-aqueous phase liquid) must begin immediately. Remove LNAPL and define the aerial extent of the release.

Result: Begin assessment in anticipation of submitting the Site Characterization Report to OPS within 180 days of the release discovery.

Surface spill

Scenario: A customer is in the process of filling their vehicle tank and leaves the dispenser unattended to go inside the convenience store. The vehicle gas tank fills up, but the nozzle does not stop dispensing fuel. The fuel then flows onto the ground surface towards soil and a nearby sewer.

Action: Activate the emergency stop button and call 911 to report the release to the local fire department.

Apply absorbent material and spill booms to the spill area to prevent the fuel from impacting any soil or utilities (do not flush or rinse product down storm drains). Make the A/B operator (or primary contact) aware of the situation.

Contact an environmental cleanup contractor, your compliance contractor or an environmental consultant.

Result: Begin assessment in anticipation of submitting the Site Characterization Report to OPS within 180 days of the release discovery. Alternatively, OPS may request that the owner/operator complete a Surface Release Characterization

Report if the release is under 100 gallons and no impacts to soil, groundwater or storm sewers were observed.

OPS recommends contracting with a Recognized Environmental Professional to aid in your release response and reporting.

Surface Spills

Release Reporting

A surface spill or overfill of a regulated substance is considered a confirmed release when: 1) any spill or overfill quantity is not cleaned up within 24 hours, or 2) a spill or overfill quantity is greater than 25 gallons.

Emergency Response

Any release of an OPS regulated substance that has or may impact waters of the State, no matter how small, must immediately be reported to the CDPHE emergency response center. 1-877-518-5608

Upon discovery of a regulated substance on the ground or in surface water, or if a regulated substance has the potential to create a fire, explosion or acute health hazard, emergency response action shall be initiated immediately.

Site Characterization Report

If the released product has come into contact with surficial soil, surface water, groundwater, a storm water collection system that discharges to surface water, or a sensitive environment, the owner/operator is required to conduct a "XRef" site characterization in accordance with this guidance.

Surface Release Characterization Report

If the owner/operator can demonstrate that less than 100 gallons of product was released and that the released product did not come in contact with surficial soil, surface water, groundwater, a storm water collection system that discharges to surface water, or a sensitive environment, the owner/operator may submit a Surface Release Characterization Report (SRCR) in accordance with the

OPS Instructions for a SRCR. The primary elements of a SRCR are described below.

Surface Release Narrative

A narrative must be provided that summarizes the events pertaining to the release including the following:

- A chronology of the initial response
- Weather conditions at the time of the release and during the cleanup
- Identification of responders including names and contact information
- Abatement activities and disposition of abatement derived waste.

Surface Release Location Map

A site map must show the surface area of the release, and include the following:

- North arrow
- Property boundaries
- Locations and names of streets
- Site buildings and structures
- Location of USTs, ASTs, and dispensers, and product piping runs
- Type of ground cover (e.g., asphalt, concrete)
- Groundwater monitoring wells and tank pit observation wells.

Responder Incident Reports

Attach all available reports from private contractors and local, county, and state agencies. Typically, the fire department's response report will be available.

Photo Documentation

Provide photos to document the surface release area, abatement and cleanup activities, and post abatement and mitigation conditions at the site.

Waste Disposal Manifests

Attach copies of all manifests provided by transporters, landfills, disposal and treatment facilities.

Risk Assessment

Releases to the environment may pose a risk to human health and the environment that need to be evaluated when the release occurs. This evaluation includes the identification of POEs (points of exposure[1]) and analysis of exposure pathways.

Click on the arrows below for information about POEs, exposure pathways and risk modeling in association with release events.

POEs

POEs for Chemicals of Concern are:

- Property boundaries
- Surficial soils (upper meter of soil[2])
- Subsurface utilities
- Structures
- Groundwater wells
- Surface water
- **Sensitive environments**[3], which include: critical habitat for federally endangered or threatened species; national parks; national monuments; national recreation areas; national wildlife refuges; national forests; campgrounds; recreational areas; game management areas; wildlife management areas; designated federal wilderness areas; wetlands; wild and scenic rivers; state parks; state wildlife refuges; habitat designated for state

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[1] is the location at which a person or sensitive environment is assumed to be exposed to a chemical of concern.

[2] If the upper meter of soil is covered with an impervious material, this pathway is considered incomplete.

[3] An area of particular environmental value where regulated petroleum contamination could pose a greater threat than in other less sensitive areas.

endangered species; fishery resources; state designated natural areas; wellhead protection areas; classified groundwater areas; and county or municipal parks.

POEs for methyl tert-butyl ether are water supply wells and surface water features that are used for human consumption.

All impacted or potentially impacted POEs must be identified during site characterization. Surface water and water wells must be identified within a 2,500 radius from the release during site characterization.

POEs are described and depicted below.

Point of Exposure	Point of Exposure Description
Property boundaries	This is considered to be a POE because neither OPS nor the owner/operator can control activities that could potentially occur beyond the property boundary (e.g., well installation, utility installation or building construction).
Surficial soils	All soils located from the ground surface to a depth of one meter below ground surface and are considered POEs to protect a receptor from exposure through dermal contact, inhalation or ingestion.
Subsurface utilities	Subsurface utilities are considered POEs to protect a receptor from exposure to vapors in utility corridors.
Structures	Structures (with or without a basement) that are not involved in the dispensing of petroleum and are potentially inhabited are considered POEs.
Groundwater supply wells	Water supply wells (excluding monitoring wells) are considered POEs.

Surface water	Surface waters are considered a POE to protect a person from exposure through dermal contact, ingestion or inhalation.
Sensitive environments	Where surface water is present, OPS will treat it as a surface water POE; however, sensitive environments may be subject to more stringent regulation by the agencies directly involved in the management and preservation of these environments (e.g., National Park Service, Colorado Division of Natural Resources, US Army Corps of Engineers or local governments).

Sample figure depicting the POEs

Potential groundwater POEs for release events should be evaluated by using the Colorado Department of Natural Resources' AquaMap Potential surface water POEs should be evaluated by referring to the Colorado Department of Public Health and Environment's Stream Classifications and Water Quality Standards.

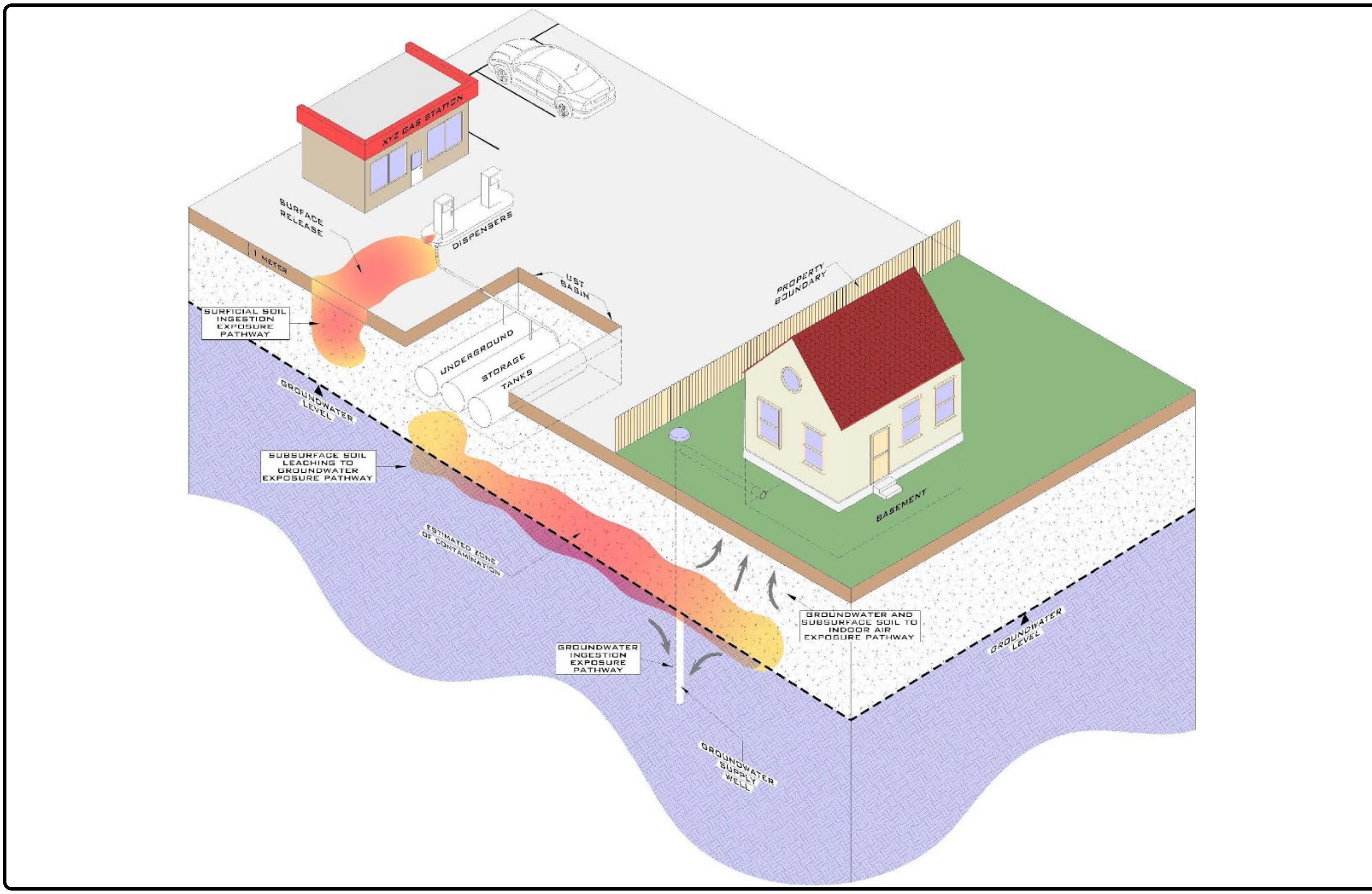
Exposure Pathways

An exposure pathway is the path that a contaminant takes from the source of the release to a POE. Each exposure pathway accounts for both the pathway medium (e.g., subsurface soil) and the mode of transport to the POE (e.g., ingestion of groundwater impacted by leachate). All exposure pathways are considered complete (open) until it can be demonstrated that a POE will not be impacted by the release. At that time, the exposure pathway is either considered incomplete or closed/eliminated. The potential for inhalation via vapor intrusion is evaluated by using the Petroleum Vapor Intrusion guidance. If the POE exists within the known or predicted extent of contamination and the exposure pathway is complete, there is a potential risk of exposure.

The exposure pathways are described and depicted below.

Exposure Pathway	Exposure Pathway Description
Groundwater ingestion	This exposure pathway is initially considered complete if groundwater or surface water are impacted above the Tier 1 RBSLs (risk-based screening levels).
Groundwater to indoor air	This pathway must be evaluated if groundwater is impacted above the Tier 1 RBSLs and an inhabited structure is present within the influence of hydrocarbon contamination. Structures involved with dispensing petroleum products as part of regular operations are excluded.
Surficial - Ingestion, dermal contact, inhalation	This pathway must be considered if soil is impacted above the Tier 1 RBSLs for surficial soil, or above 500 mg/kg for TPHs (total petroleum hydrocarbons), from

	ground surface to one meter below ground surface. If the upper meter of soil is covered with an impervious material, this pathway is considered incomplete.
Subsurface Soil to Indoor Air	This pathway must be considered if there are vapor concentrations in soil which exceed the Tier 1 RBSLs for soil contamination volatilizing to indoor air or TPH concentrations in soil greater than 500 mg/kg. Structures involved with dispensing petroleum products as part of regular operations are excluded.
Subsurface Soil Leaching to Groundwater	This pathway must be considered if soil contamination is present above Tier 1 RBSLs or above 500 mg/kg TPH at depths greater than one meter.



Sample figure depicting exposure pathways

Risk Modeling

Contaminant fate and transport modeling is used to assess the risk to human health and the environment from leaking storage tank sites. It provides a mechanism to predict contaminant concentrations in the future at a POE, such as groundwater supply wells and surface water bodies used for drinking water. Modeling can also be used to establish SSTLs (site-specific target levels). These SSTLs can be used to eliminate an exposure pathway by allowing on-site concentrations greater than the Tier I RBSLs to remain on-site.

Additional Resources

[ASTM Risk Assessment]

[ITRC Risk Assessment]

Conceptual Site Model

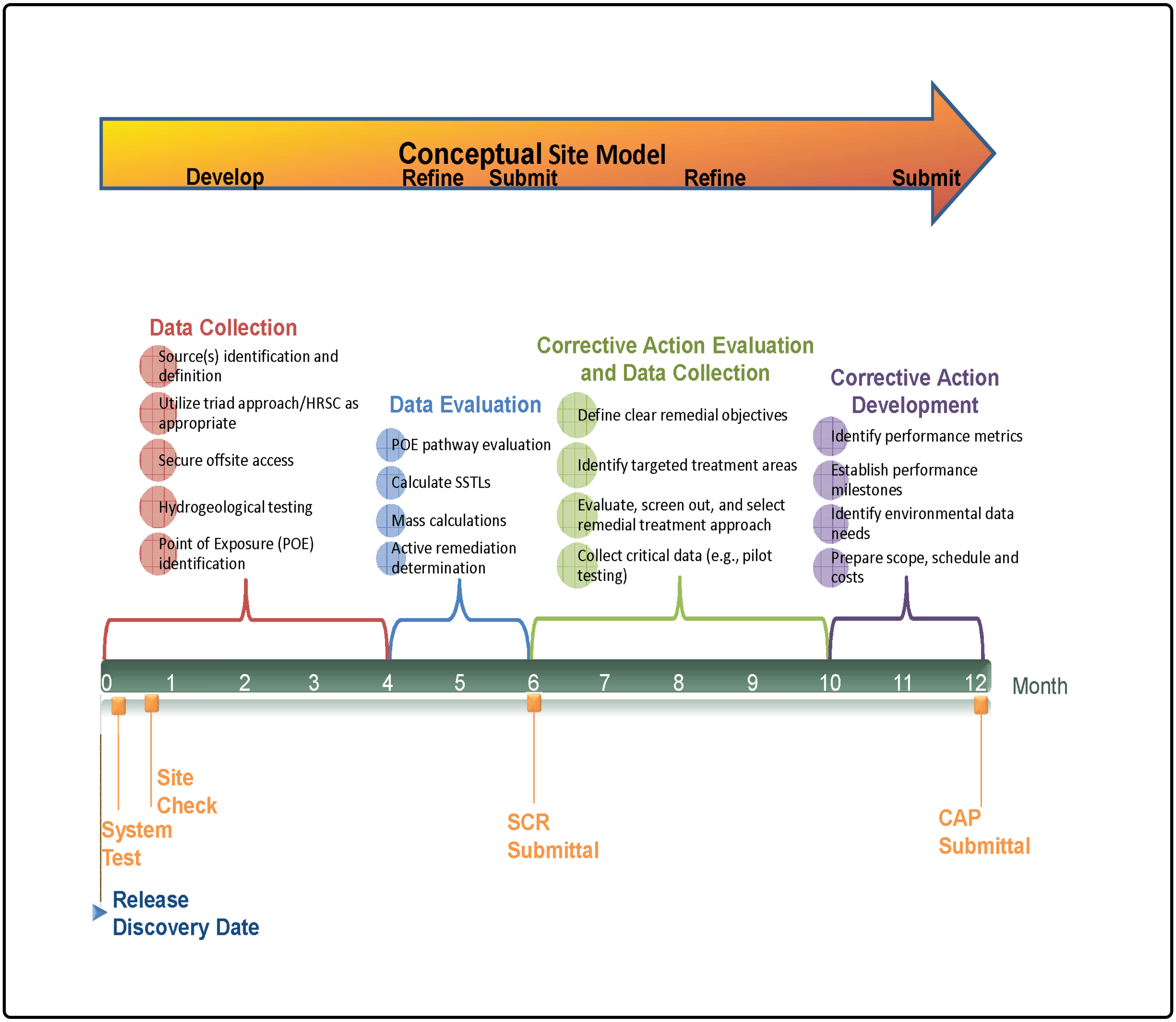
A CSM (Conceptual Site Model) is a written and illustrative description of the release site (based on all known environmental and site information) and is the primary communication tool utilized between all release stakeholders. A CSM is required in all reports submitted to OPS. CSM development is a dynamic process that continually incorporates new site information, beginning from release discovery through release closure.

A thoroughly developed CSM should identify the following:

- Contaminant concerns and remedial objectives associated with each contaminant phase of a the release
- Next steps to be taken
- Data gaps

OPS strongly recommends incorporating the Triad Approach early into the CSM development process. This approach identifies systematic project planning, real-time measurement technologies and dynamic work strategies as pillars that lead to reducing project uncertainty.

The following figure depicts the components of a CSM and reporting due dates.



Site characterization efforts lead to the development of an initial CSM. The CSM is continuously refined as corrective action efforts are implemented and new project data is gathered. It is important to know where your project is within the CSM, but it is also important to understand that this dynamic process is not linear and that new information may lead to reassessing work that has already been completed. Developing, refining and understanding the CSM will lead to targeted risk reduction and reduced project time and costs. The following sections identify the components of the CSM.

Data Gathering

The CSM should be thoroughly defined upon completion of site characterization activities. All data associated with the release event should be summarized in the CSM narrative and depicted in figures (plan and cross-sectional view) and tables, as appropriate, to build a basis for data sharing and release understanding.

Release Discovery

The CSM should summarize the understanding of the release and identify the sources, causes and repairs made to the storage tank system. The CSM should also clearly identify the chemicals of concern, if the release was chronic or acute, the estimated duration of the release and if the release is potentially ongoing. Unknown information should be identified as data gaps.

Vertical and Horizontal Release Extent

The CSM should summarize the vertical and horizontal extent of all chemicals of concern in the subsurface. Thorough definition and understanding of the contaminant distribution during site characterization will lead to the development of appropriate remedial objectives, targeted treatment areas, significant cost savings and shorter project cleanup times.

Site/Release Understanding

A historic understanding of the release site is critical for reducing data gaps and developing the CSM. Previous petroleum storage tank systems and configurations should be presented on site figures and evaluated for data gap understandings. Previously documented releases and remedial actions associated with a facility should also be summarized in the CSM narrative and evaluated relative to the current release event.

Hydrogeologic Understanding

Hydrogeologic conditions should be well understood and incorporated into the CSM as they relate to contaminant distribution and transport. A thorough understanding of hydrogeologic conditions can lead to an enhanced understanding of distribution and migration pathways, which can lead to the development of appropriate and targeted corrective actions. Contaminant mass transport and mass storage areas should be identified.

Point of Exposure Identification

All points of exposure should be identified early on during release discovery and summarized within the CSM. Ultimately, actual or potential impact to a point of exposure drives risk-based corrective action decisions.

Data Evaluation

Data evaluation should happen in concurrence with data gathering and should result in the collection of additional data until data evaluation objectives are met.

Present the following data evaluation components in the CSM upon completion of site characterization activities, summarize them in the CSM narrative and depict them in plan and cross-sectional figures and tables as appropriate. Abate acute health and safety risks immediately until the risk has been adequately reduced.

Point of Exposure/Exposure Pathway Evaluation

Identify all impacted or potentially impacted points of exposure during the initial CSM development. Additionally, evaluate and identify all exposure pathways as either complete or incomplete during this process. Points of exposure and exposure pathway evaluation are major factors when considering whether a release poses risk or if a release event may be closed.

SSTL Calculations

SSTLs (site-specific target levels) must be calculated for on-site locations that exceed the Tier I risk-based screening levels and form a footprint for remedial objectives. SSTLs should be established for source areas, mid-plume and the distal end of the plume to identify potential treatment areas.

Contaminant Mass Estimates

Complete mass estimates for all identified potential treatment areas, as they are the criteria for evaluating remedial applications and establishing performance milestones. OPS understands that mass calculations are difficult to precisely determine. Order of magnitude approximations (e.g., 500 pounds or 5,000 pounds TPH) or mass estimate ranges (e.g., between 10,000 pounds and 20,000 pounds) are appropriate for understanding the nature and magnitude of the release. Separate mass estimates for different potential treatment areas are appropriate.

Data Gap Identification

Data gap identification is a critical part of the data evaluation process, but not all data gaps are the same. As such, qualify data gaps as either significant gaps that require the collection of additional information to properly develop the CSM or minor data gaps where additional data collection will not likely result in an enhanced site understanding. Data gaps can be identified at any time during data collection activities or data evaluation activities. Ideally, data gaps will be identified during data collection activities (e.g., real-time data measurement) such that field decisions can be made to address the gap.

Overall, data gathered during the site characterization phase should lead to a well-developed CSM such that the aforementioned data evaluation components are thoroughly understood.

Active Remediation Determination

Evaluate the need for active remediation once data gathering objectives and the data evaluation objectives have been completed. Clearly identify an active remediation evaluation within the CSM. Corrective Action development should occur if it is determined that active remediation is necessary to reduce the risk associated with the release.

Corrective Action Plan Development

Utilize the corrective action process to select and implement the most technically and economically feasible remedial methods to reach the remedial objectives identified for the release site. Critical components of the CAP (corrective action plan) development process as they relate to the CSM are described below. These components should be summarized in the CSM narrative and depicted in plan and cross-sectional figures and tables as appropriate.

Identify Contaminant Concerns

The initial step of CAP development is to identify contaminant concerns associated with each phase of the petroleum release. The CSM should clearly identify these concerns based on the results of the SCR.

Clearly Define Remedial Objectives and Targeted Treatment Areas

Clearly state the remedial objectives in the CSM and plainly identify the targeted treatment area for the objective. Clearly defining the remedial objectives and treatment areas highlights the understanding of the risk associated with the release and allows all stakeholders to understand the extent and purpose of the corrective actions.

Identify Critical Data Needs for the Selected Remedy

Follow the remedial selection process to select appropriate remedial technologies based on the site understanding and other remedial evaluation factors. Identify and gather critical data needs to confirm the selection of the cleanup approach and enhance the full-scale design of the system to ensure that it meets the remedial objectives.

Identify Performance Metrics and Establish Milestones

Identify remedial system performance metrics and performance milestones in the CAP CSM development phase. These metrics and milestones should be the basis for evaluating the success, progress or failure of the selected remedy, as well as for the corrective action progress reporting frequency.

Identify Environmental Data Needs

Identify environmental data needs (monitoring well data, additional spatial groundwater data and soil confirmation/evaluation data) as they relate to the remedial objectives, targeted treatment areas and performance milestones. Specify chemicals of concern and other analytical needs. The location and frequency of data collection should be specified and relevant to the remedial objectives and performance milestones.

Corrective Action Data Evaluation

Corrective action should be implemented consistent with the approved CAP (corrective action plan). Any deviations from the approved CAP should be documented. The following components should be incorporated into the CSM as the implemented corrective action progresses toward meeting the remedial objectives and, ultimately, toward site closure.

Evaluate New Data

The performance metric and environmental data identified in the CAP phase should be incorporated into the existing CSM. These data should be compared to the expectations identified in the CAP development phase.

Determine Whether Performance Milestones Were Met

Post-implementation evaluation reports should identify whether the remedial action is performing as expected. If the implementation is not performing as expected, optimization efforts should be identified and implemented.

Determine Whether Remedial Objectives Were Met

Ideally, a well-defined CSM will lead to well-defined remedial objectives, selection of the right remedial approach, appropriate performance metrics and milestones and the collection of critical data to evaluate the progress of the site cleanup. The CSM should be updated to incorporate a review of the remedial objectives as corrective action progresses. Data gaps are likely, and redevelopment of the remedial objectives should be re-evaluated if the objective is not met.

Data gaps should be identified in the CSM during this evaluation phase as soon as they become apparent. Data gaps may be related to the corrective action (e.g., it did not perform as expected) or to the remedial objective (e.g., the corrective action performance expectations were met, but the remedial objective was not met).

No Further Action Evaluation

No Further Action evaluations should occur during both the site characterization and the corrective action data evaluation phases. The CSM narrative should clearly identify what the cleanup goals are and what the targeted tiered closure goal is. For many sites, corrective action is not necessary, as the release may already be considered of low risk to human health and the environment; however, it is also true that many sites will go through multiple corrective action efforts to appropriately reduce the associated risk. Understanding and following the CSM process significantly increases the understanding of the release, leads to targeted remedial efforts and reduces the time and costs associated with a release event.

Additional Resources:

[ASTM Standard Guide for Developing Conceptual Site Models for Contaminated Sites]

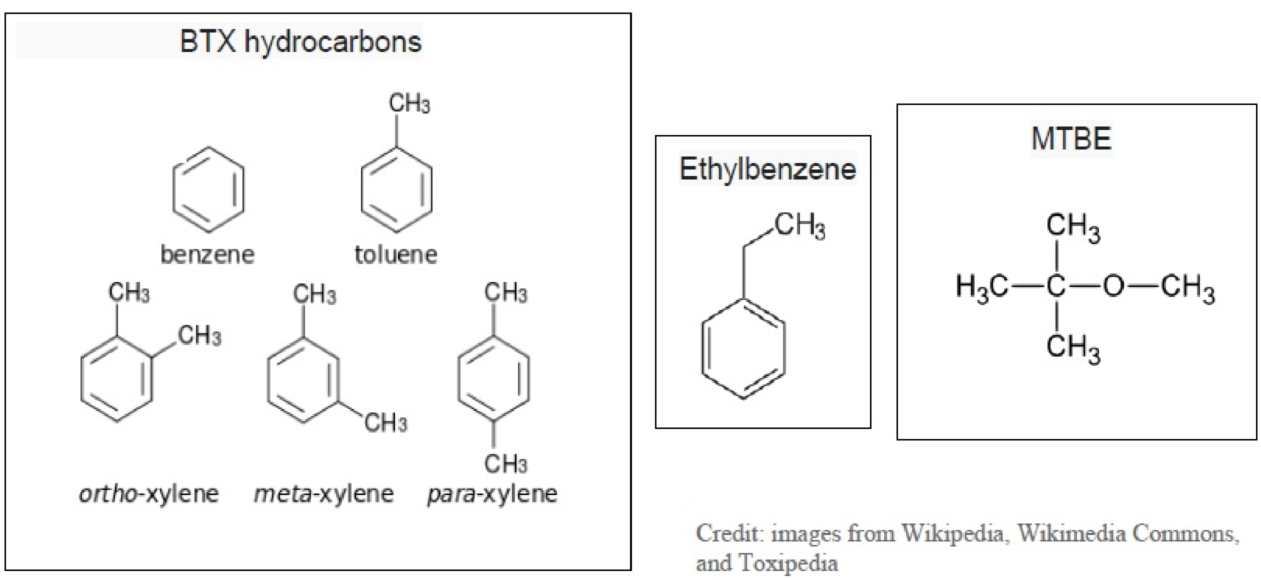
[Conceptual Site Model Checklist]

Chemicals of Concern

Regulated substances may contain COCs (chemicals of concern) that can be harmful to human health or the environment. These COCs, if released from a regulated tank system, may pose an unacceptable risk. This guidance is intended to identify chemicals of concern and their associated analytical methods.

Primary COCs

Primary COCs include benzene, toluene, ethylbenzene, xylenes (BTEX) and methyl tert-butyl ether (MTBE) based on their prevalence in regulated petroleum products and their mobility in the subsurface. Primary COCs must be [characterized]() after a release has been confirmed. Benzene is a COC based on its carcinogenic and toxicological properties, while toluene, ethylbenzene, and total xylenes are COCs based on their toxicological properties. Acute or chronic exposure to BTEX via inhalation, ingestion or direct contact pathways may cause increased carcinogenic or toxicological risk.



Credit: images from Wikipedia, Wikimedia Commons, and Toxipedia

MTBE is an oxygenate that was used in Colorado from the late 1970s through 2002. Although EPA has not set a national standard for MTBE in drinking water, a Drinking Water Advisory was issued in 1997 that established a taste threshold of 0.04 mg/L and an odor threshold of 0.02 mg/L. EPA has developed Regional Screening Levels for MTBE. Groundwater ingestion is the only exposure pathway for MTBE.

Additional information about primary COCs is available via the CDC and EPA's Water Resources and Risk-Based Screening Table.

BTEX and MTBE are required to be characterized in groundwater. BTEX must also be characterized in soil and potentially in soil vapor, depending on evaluation of the air exposure pathway

Secondary COCs

Secondary COCs include TPHs (total petroleum hydrocarbons) and PAHs (polynuclear aromatic hydrocarbons). TPH is divided into the following three groups based on their range of carbon chains:

- Total volatile petroleum hydrocarbons (TVPH; gasoline range organics; C6-C10)
- Total extractable petroleum hydrocarbons (TEPH; diesel range organics; C11-C28)
- Total recoverable petroleum hydrocarbons (TRPH; oil range organics; C29-C35)

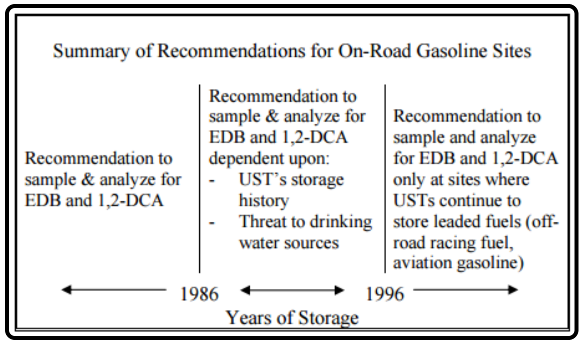
TPH must be fully defined to the threshold limit of 500 mg/kg in soil during the characterization phase. If a soil sample is collected at the soil-groundwater interface and is above the 500 mg/kg threshold limit, submerged soils should be collected until the soil is fully defined to 500 mg/kg. During the remediation phase, the continued analysis of TPH in groundwater should be evaluated on a site-specific basis.

PAHs must be characterized if the 500 mg/kg threshold limit for a TEPH or TRPH range in soil is exceeded. Some PAHs are considered secondary COCs based on their carcinogenic and toxicological properties. PAHs should be analyzed from the unsaturated soil sample with the highest TEPH or TRPH concentration that exceeds the threshold limit, regardless of the presence of BTEX. The priority PAHs are listed in the Tier I RBSLs table.

If PAH concentrations are below Tier I RBSLs in the unsaturated soil sample with the highest TEPH or TRPH concentration, no further PAH characterization is necessary. However, if PAH concentrations exceed Tier I RBSLs in the unsaturated soil sample, the vertical and horizontal extent should be defined to below Tier I RBSLs. If PAHs exceed Tier I RBSLs in the capillary fringe or smear zone, groundwater samples should be collected for PAH analysis. However, based on the ubiquitous presence of PAHs in urban areas from other sources (e.g., airborne deposition from automobile combustion; coal-tar based pavement sealers), a background groundwater sample must also be collected for PAH analysis at a location upgradient from and completely removed from the release source area.

Petroleum Fuel Additives

A variety of compounds have been added to petroleum fuels over the years to enhance certain performance properties of the fuel. The following COCs should be analyzed to determine if there is reason to suspect that the additives were used at the site. If these COCs are identified during characterization, additional monitoring and remediation will be handled on a site-specific basis.



1,2-DCA (1,2-Dichloroethane)

Between 1949 and 1989, 1,2-DCA was an anti-knock additive for leaded gasoline and was selected as a COC based on its toxicological properties. It is a potential carcinogen via the inhalation, absorption, ingestion and direct exposure pathways. A release sites should be analyzed for 1,2-DCA if the site is suspected to have dispensed leaded gasoline and/or operated prior to 1996. [Figure courtesy of EPA]

EDB (Ethylene Dibromide)

Leaded gasoline was banned in 1989, but it can still show up in a release investigation.

EDB was mainly used as a lead scavenger in anti-knock gasoline mixtures (particularly in aviation fuel) and is a COC based on its carcinogenic and toxicological properties. It is a potential carcinogen via the inhalation, absorption, ingestion and direct contact exposure pathways. A release site should be analyzed for EDB if the site is suspected to have dispensed leaded gasoline.

TEL (Tetraethyl Lead)

TEL was the chief anti-knock gasoline additive beginning in the 1920s until it was gradually phased out beginning in 1978. TEL is a COC because it can cause acute or chronic lead poisoning if inhaled, ingested or absorbed through the skin. Samples from a release site should be analyzed for TEL if the site is suspected to have dispensed leaded gasoline.

Ethanol and Methane

Ethanol is a current oxygenate additive for gasoline and comprises 6-83% of the total fuel volume. Methane is a daughter product of ethanol and would most likely be found in soil vapor within the unsaturated zone. Methane is nonpoisonous, but can be an asphyxiant and an explosive hazard when mixed with air. A release site should be analyzed for ethanol and methane if the release is from an ethanol-blended fuel.

Other Regulated Compounds

There are several types of regulated products commonly used for commercial purposes. These include new lubricating oil, used waste oil, petroleum solvents and glycols. These other regulated compounds should be analyzed for if a release is confirmed from a regulated tank that contains these products. If these COCs are identified during characterization, additional monitoring and remediation will be handled on a site-specific basis.

New Lubricating Oil and Waste Oil

BTEX, TRPH and PAHs are required analytes for assessing releases from new lubricating oil or used waste oil tanks. Other parameters can and should be added consistent with information about the source of the waste. For example, if historical information or facility operational knowledge indicates non-petroleum or chlorinated solvents were disposed in a waste oil tank, a full suite volatile organic compounds analysis is required to determine if there are any non-petroleum hazardous contaminants present that could adversely affect the environment. Contact the Colorado Department of Public Health and Environment at (303) 692-3300 if non-petroleum hazardous contaminants, such as chlorinated solvents, are present.

Petroleum Solvents

Petroleum solvents include rubber solvent, mineral spirits and naphtha. The analytical parameters for characterization and remediation efforts from tanks known to contain petroleum solvents include TVPH, volatile organic compounds, and PAHs. Petroleum solvents do not usually contain sufficient quantities of BTEX to allow their measurement in soil and water samples.

Glycols

Glycols are organic compounds that contain alcohol. The most common glycols are ethylene glycol and propylene glycol, which are used as antifreeze applications in automotive cooling systems and deicing operations at airports.

Unknown Petroleum Products

A phased analytical approach is often valuable to develop a monitoring plan for unknown petroleum products. Information about the product contained in Safety Data Sheets may be useful for selecting the appropriate analytical method. It is recommended that the sample with the highest apparent contamination be analyzed for TVPH, TEPH and TRPH to determine the range of organics.

Laboratory Analytical Methods

Appropriate laboratory analytical methods must be used to detect and quantify substances present or suspected to be present at the site. The Regulated Substances table provides guidance on accepted analytical methods to use and is based on EPA publication SW-846. Methods for evaluating solid waste must be selected based on the need to measure contaminants at or below the lowest of the applicable cleanup levels.

Site Characterization

When a release from a regulated tank system has been confirmed, OPS requires the owner/operator of the tank system to characterize the release.

The purpose of site characterization is to:

- Define the extent of the release
- Determine the distribution of contamination in the subsurface
- Determine if **POEs**[1] are impacted or potentially impacted
- Evaluate all exposure pathways
- Determine if active remediation is required

Significant advancements have been made over the past few decades in characterization project planning, execution and available tools. OPS recommends utilizing these tools and practices for a release event, as they have demonstrated an ability to increase the understanding of the release, reduce the project life cycle of a release, lead to targeted remedial efforts and reduce the total project costs.

- The Triad Approach identifies systematic project planning, dynamic work planning and real-time data collection as three areas of focus that, when utilized together, form a process of reducing uncertainty for environmental projects.
- A practical application of the Triad Approach is the use of high-resolution site characterization tools, such as membrane interface probes, laser-induced fluorescence and hydraulic profile tools to gather critical release and site information. When used in the context of the Triad Approach, high-resolution site characterization tools can achieve the project goal of

[1] The location at which a person or sensitive environment is assumed to be exposed to a chemical of concern.

characterizing the release in a much shorter time than it would take using traditional assessment planning and execution by collecting real-time data and utilizing that data to make real-time, informed decisions.
- Incorporating green and sustainable practices into site characterization and remediation activities has also emerged as a sound and lasting advancement in the way we address releases to the environment. OPS recommends that you not only consider how to characterize and reduce the risk associated with a release, but you should also consider how to minimize energy expended and air pollutants generated, as well as to reduce, reuse and recycle equipment, material and waste.

The information provided below will identify OPS expectations for conducting complete characterization efforts for the purpose of assessing the risk associated with a petroleum release. The data gathering and data evaluation components of site characterization must be summarized in the Conceptual Site Model for the release.

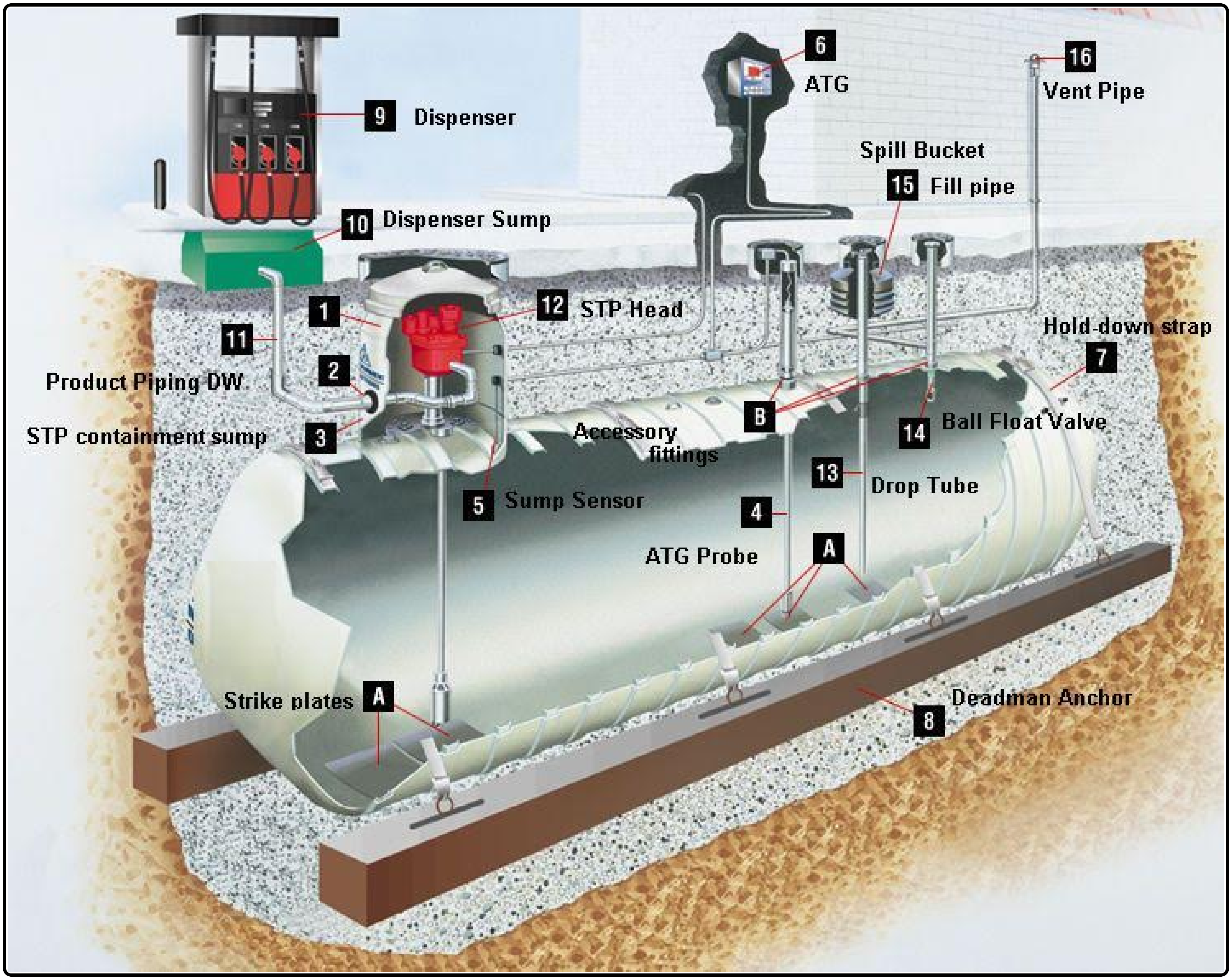
Release Source Identification, Cause and Repair

The first step of site characterization is to determine which regulated substances were released, the sources of the release and identify the portion of the tank system from which the release originated. It is essential to investigate all possible source areas when defining a release (both recent and historical). Document specific repairs to the release source.

Potential release sources include:

- Fuel dispensers (check valve, filter, fire/shear valve, flex connector or other fittings)
- Product lines (lines or connections)
- Tank systems (device failure, device override or spill bucket failure)
- Submersible turbine sump pump

- Surface spills (customer error, defective nozzle, breakaway or leaking nozzle)



Components of a typical UST system

Defining the Vertical and Horizontal Extent of the Release

For releases that will likely require active remediation, OPS recommends delineating the

Define the extent of contamination both vertically and horizontally to below OPS Tier I RBSLs for soil and groundwater and to the TPH threshold level of 500 mg/kg in soil. During site characterization, collect adequate COC soil data from the source area (vadose, smear and saturated zones) and transport zones (smear and saturated zones). The nature by which these data are collected (e.g., high resolution tools vs. traditional assessment tools) and the density of sample locations are dependent upon where you are within the contaminant distribution (e.g., higher density in source areas) and the magnitude of the release (e.g., high-magnitude releases should be assessed with high-resolution tools).

contaminant distribution with high-resolution characterization tools and then placing monitoring wells in identified critical areas (e.g., source areas, high mass areas and mass transport zones).

Collection of groundwater data is required unless it can be conclusively demonstrated that all COC impacts are above the water table and do not have the potential to impact groundwater. Establish monitoring points within the plume, and establish **points of compliance**[1] upgradient of POEs to evaluate risk. Present the explanation of the distribution in site figures (plan view and cross-section) and in the CSM.

Although soil samples should be used to define the extent of the contaminant mass above and below the water table, only groundwater samples should be used to determine whether the groundwater ingestion exposure pathway is complete or incomplete.

Release Source Area

Source area delineation refers to the area immediately beneath and around the identified release sources and is a critical part of site characterization. The source area typically contains the majority of the contaminant mass. OPS recommends a higher density of horizontal COC assessment locations and a higher

[1] a location at which empirical data can be collected to demonstrate that an associated POE is not impacted or threatened to be impacted by the release

density of soil samples collected throughout the vertical profile of those horizontal locations.

Significant contaminant mass may reside beneath the water table based on the initial deposition and driving head of the contaminant body. Complete vertical delineation of the source area until you observe non-impacted soil. Based on the severity of the release, it may be necessary to collect multiple soil samples (i.e., vadose zone, smear zone and saturated zone) in a single location to completely characterize the mass distribution in soil.

Plume Definition

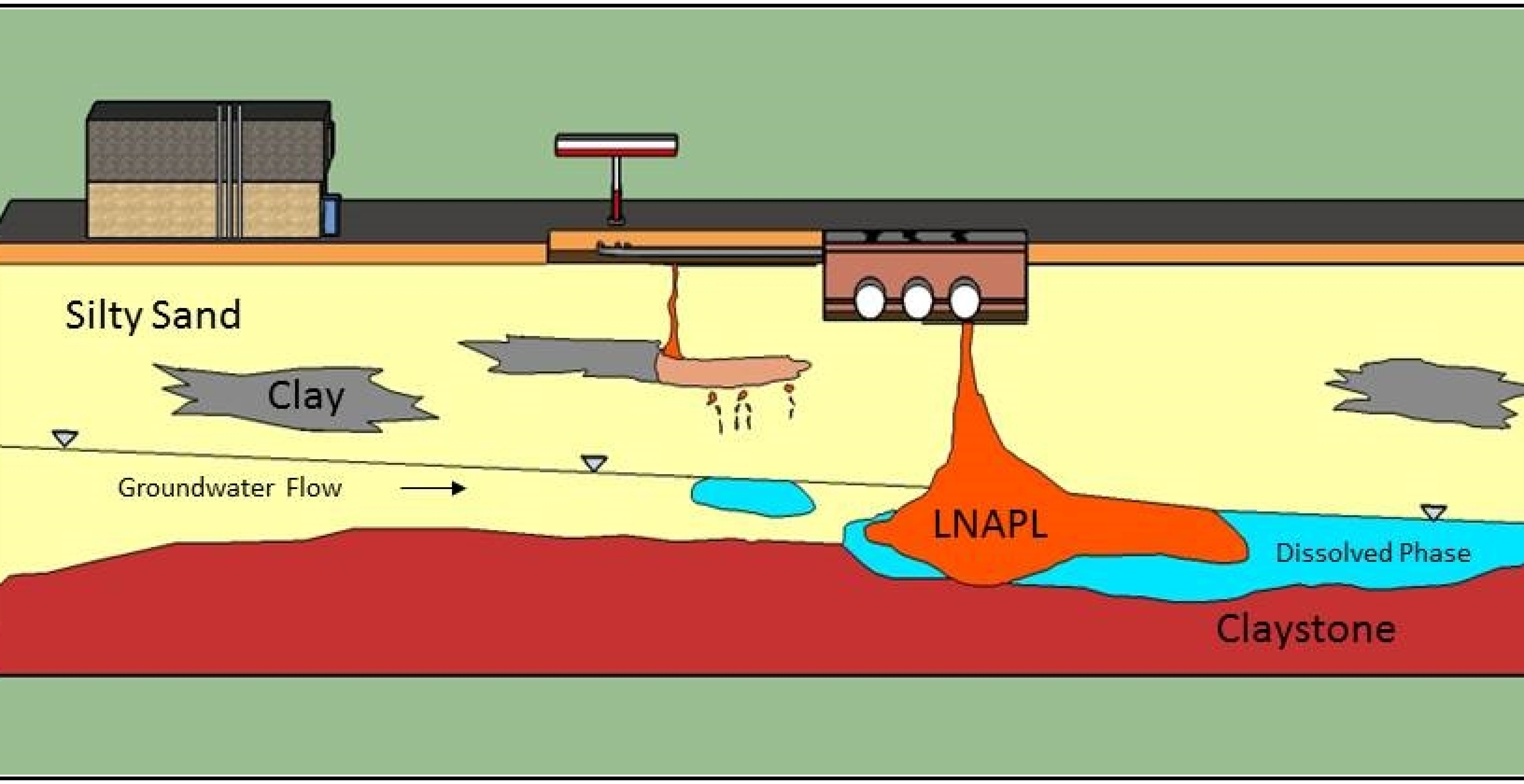
The area between the source of the release and the extent of contamination contains the contaminant mass that has migrated through soil pores (vadose or smear zone) due to hydraulic head, diffusion, dispersion or advection. Mid-plume contamination may or may not be in direct contact with the source area, depending on the age of the release, abatement/remediation efforts and the hydrogeologic conditions. Adequate data collection within the mid-plume area is necessary to understand contaminant distribution.

Determine the horizontal extent of contamination by collecting groundwater data and defining the contamination hydraulically upgradient, crossgradient, and downgradient of the release. Installation of point of compliance monitoring wells are required upgradient of all POEs identified as having the potential to be impacted. You may use fate and transport modeling or high-resolution characterization data to optimize the placement of plume-defining monitoring wells.

It is likely that there will be two different point of compliance locations at sites that have both BTEX and MTBE dissolved-phase impacts above the Tier 1 RBSLs - a location for BTEX immediately upgradient of the property boundary (or the closest POE other than the property boundary) and a location for MTBE upgradient of a water supply well used for human consumption or a surface water feature used for human consumption.

LNAPL

All releases from petroleum storage tanks begin as LNAPL contacting soil and potentially migrating to groundwater. During the advancement of soil borings and the installation of monitoring wells (or other characterization techniques), determine the presence of pore-trapped (residual saturation) LNAPL and mobile phase LNAPL (LNAPL that is observed in monitoring wells).



Hypothetical petroleum release

Utility Clearance

Complete utility notifications before moving forward with any intrusive work. These requirements can vary by location, but all utility locates must start with the [Colorado 811 notification](#).

Practice adequate care to avoid impacting fuel system components and utility service lines. Private utility locates, as-built drawings, hand augering and potholing/air knifing are all additional supplemental methods of utility clearance.

Soil Sampling

Traditional Soil Sample Collection

Commonly-used soil sample collection methods include hand augers, direct-push technology, auger drilling and excavation equipment. Other drilling methods may be necessary based on geologic conditions. Utilize professional judgment to determine the appropriate drilling and soil-sampling method. Collecting any soil sample submitted for laboratory analysis must follow an industry-accepted collection procedure. Air knife sampling and composite sampling are not acceptable soil-sampling methods.

Soil Sample Logging, Field Screening and Sample Selection

Continuous core sampling is preferred for source area characterization instead of five-foot sample intervals.

Characterization requires careful screening and collection of soil samples by experienced field personnel. Describe all soil samples using the Unified Soil Classification System and use an OVM (organic vapor meter) to screen them, such as a PID (photoionization detector). Maintain and calibrate all field screening equipment according to the COCs and manufacturer's requirements.

Do not submit soil samples for laboratory analysis that are utilized for field screening. Soil screening methodology must follow an industry-accepted collection procedure. Submit soil samples for laboratory analysis based on OVM readings or visual observations for the purpose of fulfilling the data quality objectives. You may to collect several soil samples per boring to accurately define the distribution of contamination. OPS prefers soil samples from the smear zone for samples collected during plume definition in the absence of elevated field screening readings. Record soil descriptions and PID readings on appropriate boring and well logs.

Geotechnical Sample Collection and Analyses

Geotechnical analysis of soil samples within the characterized area may be beneficial to enhance the understanding of the site lithology and may aid in the development of the CSM, fate and transport modeling and corrective action screening and selection processes.

Depending on the type of regulated substance and the age of the release, petroleum fuel additives or other regulated compounds may need to be included in the sample analyses.

Typical analyses include:

- Grain size distribution
- Fraction of organic carbon
- Bulk density
- Porosity
- Effective porosity
- Moisture content (vadose soil only)

High-Resolution Characterization Methods

High-resolution characterization applications collect data in-situ and can be used to define the extent of COC impacts, identify the presence and extent of LNAPL, estimate the site lithology and estimate the site hydraulic conductivity. High-resolution characterization methods include MIP (membrane interface probe), LIF (laser-induced fluorescence), and HPT (hydraulic profiling tool). High-resolution characterization applications incorporate dynamic work planning, real-time data measurement and 3-D computer-generated data interpretation, and OPS encourages utilizing these applications to characterize a release that is likely to require remediation.

High-resolution characterization methods can aid in:

- Source area definition
- Source area identification
- Contaminant mass estimation

- Dissolved phase distribution
- Sentinel monitoring well placement

Monitoring Wells

Monitoring Well Installation, Development and Permitting

Monitoring wells are installed for the purpose of defining the distribution of contaminants in the dissolved phase and are utilized throughout the duration of the release event to monitor COC trends. Properly-placed monitoring wells are a vital component for understanding the distribution of contaminants and the subsequent remedial design. OPS recommends placing monitoring wells based on high-resolution characterization practices when appropriate.

All wells drilled, installed or abandoned in Colorado must be completed in accordance with State Engineer regulations and other industry best practices. Permanent monitoring wells must be registered with the State Engineer's Office.

Two references for the installation of direct push monitoring wells are ASTM and ITRC.

Complete monitoring well installation, construction and development activities in accordance with industry best practices.

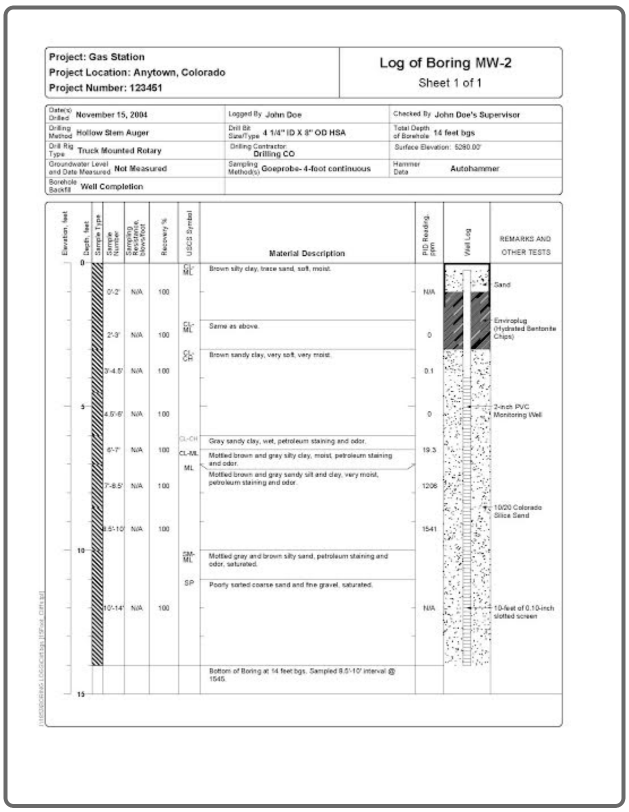
Keep these general requirements in mind.

- Monitoring wells are typically installed via auger drilling or direct-push technology.
- Monitoring wells are typically one, two or four inches in diameter and constructed of PVC. Select size and materials based on project need and professional judgment.
- Select screen size, length and placement to account for lithology, seasonal water elevation changes, contaminant target depths and minimizing dilution effects.
- Follow best management practices for equipment decontamination.

- Select filter pack, annular seal and grout materials based on industry best practices and site-specific conditions.
- Complete all monitoring wells with appropriate protective casing.
- Develop all monitoring wells to create an effective filter pack around the well screen to remove fine particles from the formation near the borehole.

<u>Soil Boring and Monitoring Well Logs</u>

Complete a graphical log for all borings and wells according to industry-accepted standards. Boring and well logs are beneficial in understanding the subsurface transport mechanisms and contaminant-bearing zones and can be used to construct cross-sectional diagrams. Logs should be scaled appropriately and contain well construction details.



Sample Soil Boring Log (click on the image to enlarge it)

Groundwater Sampling

The primary goal of groundwater sampling is to collect representative groundwater samples for laboratory analysis. Groundwater samples are commonly collected with a hand bailer, peristaltic pump or passive diffusion bag sampler. Purge, low-purge or no-purge are all acceptable methods for collecting groundwater samples. Consideration should be given to minimize purge water development, handling and disposal. Follow accepted best industry practices to ensure that a representative sample is collected and analyzed. Applicable references include those from CDPHE, the US Environmental Protection Agency, and the US Geological Survey. Sampling should occur in a progression from the least to most contaminated well.

Record measurements for the depth to water and depth to LNAPL prior to sample collection. Do not collect a groundwater sample if LNAPL is present.

Secondary groundwater parameters (DO, ORP, temperature, pH and conductivity) are beneficial to understanding the aquifer characteristics, evaluating monitored natural attenuation and evaluating other remedial treatment approaches. Collect secondary groundwater parameters prior to purging. Calibrate field instrumentation per manufacturer's specifications prior to use.

Care should be taken to ensure that groundwater is minimally agitated to reduce volatilization of COCs and to reduce turbidity. Per manufacturer's recommendations, do not decontaminate reusable equipment ; properly dispose of single-use equipment. Do not leave sampling devices in monitoring wells for reuse.

Collect samples in the appropriate sample container and handle them in a manner appropriate for the analysis. Ship samples well before the holding time is up; ideally, they should be shipped within 24 hours of sample collection.

Vapor Assessment

To assess the vapor phase of a release, see PVI guidance.

Investigation-Derived Wastes

IDW (Investigation-derived wastes) includes soil cuttings, purged water, disposable sampling equipment and disposable personal protective equipment, and they are commonly generated during the advancement of soil borings and monitoring wells, as well as during monitoring well development and sampling.

Disposal of IDW must follow state and local disposal requirements; however, consideration should be given to minimizing the amount of IDW required for disposal.

Ways to minimize IDW include:

- Utilizing assessment techniques that minimize or eliminate the generation of soil cuttings
- Utilizing uncontaminated soil cuttings as backfill when not required to be disposed off-site
- Utilizing bulk disposal of soil cuttings (e.g., rolloff) to reduce the disposal of drums since it is cost-competitive to landfill disposal
- Utilizing the Protocol for Land Application of Purge Water developed by CDPHE and OPS to allow for the on-site surface disposal of uncontaminated purge water
- Recycling surface cover (e.g., concrete and asphalt) for future reuse to reduce waste generation since it is cost competitive to landfill disposal

CDPHE maintains a list of landfills accepting petroleum-contaminated soil. OPS maintains a list of facilities accepting product and contaminated water for disposal, as well as a list of facilities accepting concrete and asphalt for recycling.

IDW from regulated USTs are exempt from RCRA regulation as hazardous waste [40 CFR 261.4(b)(10)] under the EPA UST Rules (40 CFR Part 280). However, because ASTs are not included in the EPA UST Rules, IDW from ASTs do not have this exemption.

Petroleum-contaminated media is generally exempt from hazardous waste designation, but it is possible to generate hazardous wastes during

characterization activities. For example, old releases may have resulted in significant tetraethyl lead contamination or the facility may be located within a chlorinated contaminant plume. Include manifests/bills of lading in reports to document waste disposal.

Off-site Access

The information used during the source area definition and identification of POEs should be used to evaluate which off-site properties, if any, may be impacted by the release. Access to these properties should be requested early in characterization to prevent delays in completing characterization. Copy (CC) OPS on all written requests for access. Requests could involve an individual property owner, a neighborhood or a community, depending on the data available, and may include providing the information that has been gathered at the time to the impacted property owners.

Fate and Transport Modeling

Fate and transport modeling is used for several reasons, including:

- SSTL development
- Monitoring well placement
- Exposure pathway elimination
- No Further Action requests

SSTLs

An SSTL is a risk evaluation tool that should be applied for every confirmed release that exceeds Tier I RBSLs. SSTLs are developed to determine the concentration of contaminants that could remain on-site while ensuring that the closest point of exposure will not be impacted. They must be calculated for on-site locations that exceed the Tier I RBSLs and form a footprint for remedial objectives. SSTLs should be established for source areas, mid-plume and the distal end of the plume such that potential treatment areas are identified. All modeling results must be supported by empirical data.

Site-specific data must be used for the hydraulic conductivity, hydraulic gradient and downgradient distance input parameters. Where site-specific parameters are not available for the other parameters, use default values in accordance with the Soil and Groundwater Modeling Default Parameters Table.Apply a degradation rate to the groundwater model that empirical analysis supports. Use the concentration vs. time tab of the MNA Tool to establish a degradation rate. Use 80% of the calculated degradation rate in the MNA tool in the fate and transport model.

Soil SSTLs

Complete soil modeling to build a conceptual site model and to determine if sorbed-phase contamination will present a risk to a receptor. Use an unsaturated zone model to predict leaching of the soil contamination into groundwater and volatilization rates to outdoor air. Use a saturated soil model to predict leaching of the saturated soil at or near the water table into dissolved-phase contamination. Complete modeling to the closest point of exposure. Modeling results that are above the Tier I RBSLs indicate that the exposure pathway is open.

Groundwater SSTLs

Calculate SSTLs on-site dissolved-phase groundwater contamination above Tier I RBSLs. The distance used to calculate the SSTL is the distance from the source location to the nearest downgradient point of compliance. Cleanup goals for point of compliance locations are always Tier I RBSLs. If the actual concentrations are above the calculated SSTLs, complete an active remediation evaluation.

Monitoring Well Placement

When the dissolved-phase contaminant has moved off-site and requires full characterization, use the fate and transport model to determine the placement of a monitoring well. Vary the downgradient distance input parameter in the model until the Tier I RBSL is the concentration listed in the model output.

Pathway Elimination

Consider exposure pathway elimination when the actual contaminant concentration is less than the calculated SSTL and the POE is not impacted above the Tier I RBSL. Demonstrate plume stability through empirical data that are not influenced by active remediation.

If the MTBE exposure pathway has a POE and the model fails to the point of compliance well, adjust the downgradient distance in the model to the location of the POE. If the MTBE exposure pathway does not have a POE, set the downgradient distance to 2,500 feet to assess the risk of the release. Sample the POE, as appropriate, to determine if MTBE impact has occurred. The idea is to focus on detailed POE assessment as it relates to risk reduction. For example, if the POE is a water supply well completed in a deeper confined aquifer, separated from the shallow unconfined aquifer by a competent aquitard, the pathway is considered incomplete.

No Further Action

Use Fate and transport modeling to support No Further Action requests for Tiers II, III and IV closure criteria per the closure criteria guidance.

POEs (Points of Exposure)

Evaluate actual or potential impacts to all POEs during site characterization. You may use fate and transport modeling as a method to predict potential future impact to the POEs. Impacted or potentially impacted POEs identified during site characterization require an active remediation evaluation.

Identify all POEs in the vicinity of the release and document them on report figures. For structures, show the uses of buildings, occupancy and whether basements or other subsurface features are present.

Exposure Pathways

Evaluate all [exposure pathways]() during site characterization activities and continue to evaluated them until no further action is determined. If a POE exists within the known or predicted extent of contamination and the exposure pathway is complete, there is a potential risk of exposure. Exposure pathways are considered complete, or open, until it can be demonstrated that a POE will not be impacted by the release. At that time, the exposure pathway is incomplete, or closed/eliminated. Evaluate the potential for inhalation via vapor intrusion using the Petroleum Vapor Intrusion guidance.

Assess each POE identified with a complete exposure pathway.

For example:

- Field screen and sample surface soil for laboratory analysis.
- Field screen and assess subsurface utilities.
- Sample surface water and water wells for laboratory analysis.
- Install monitoring wells between the source of the release and adjacent properties.

Hydrogeologic Parameters

Hydrogeologic parameters include:

- Depth to water
- Hydraulic gradient
- Groundwater flow direction
- Hydraulic conductivity
- Transmissivity

Use these data to develop and enhance the CSM and to aid in fate and transport modeling of contaminants to understand current and future conditions of the site.

Depth to Groundwater

The depth to groundwater is the distance between the ground surface and the top of the saturated zone. The depth to water can vary over time due to seasonal fluctuations, drought and flood. Identify the historic high and low water depth as it relates to contaminant distribution (smear zone). If LNAPL is present in a monitoring well, record the depth to the LNAPL, LNAPL thickness and LNAPL elevation. Correct groundwater elevations based on the LNAPL thickness and specific gravity.

Hydraulic Gradient and Flow Direction

The hydraulic gradient is the slope of the water table or groundwater surface and is typically expressed as a unit change in water table elevation per unit of horizontal distance (e.g., ft/ft). The groundwater flow direction is determined by lines drawn perpendicular to the groundwater elevation equipotential lines from higher to lower groundwater elevations.

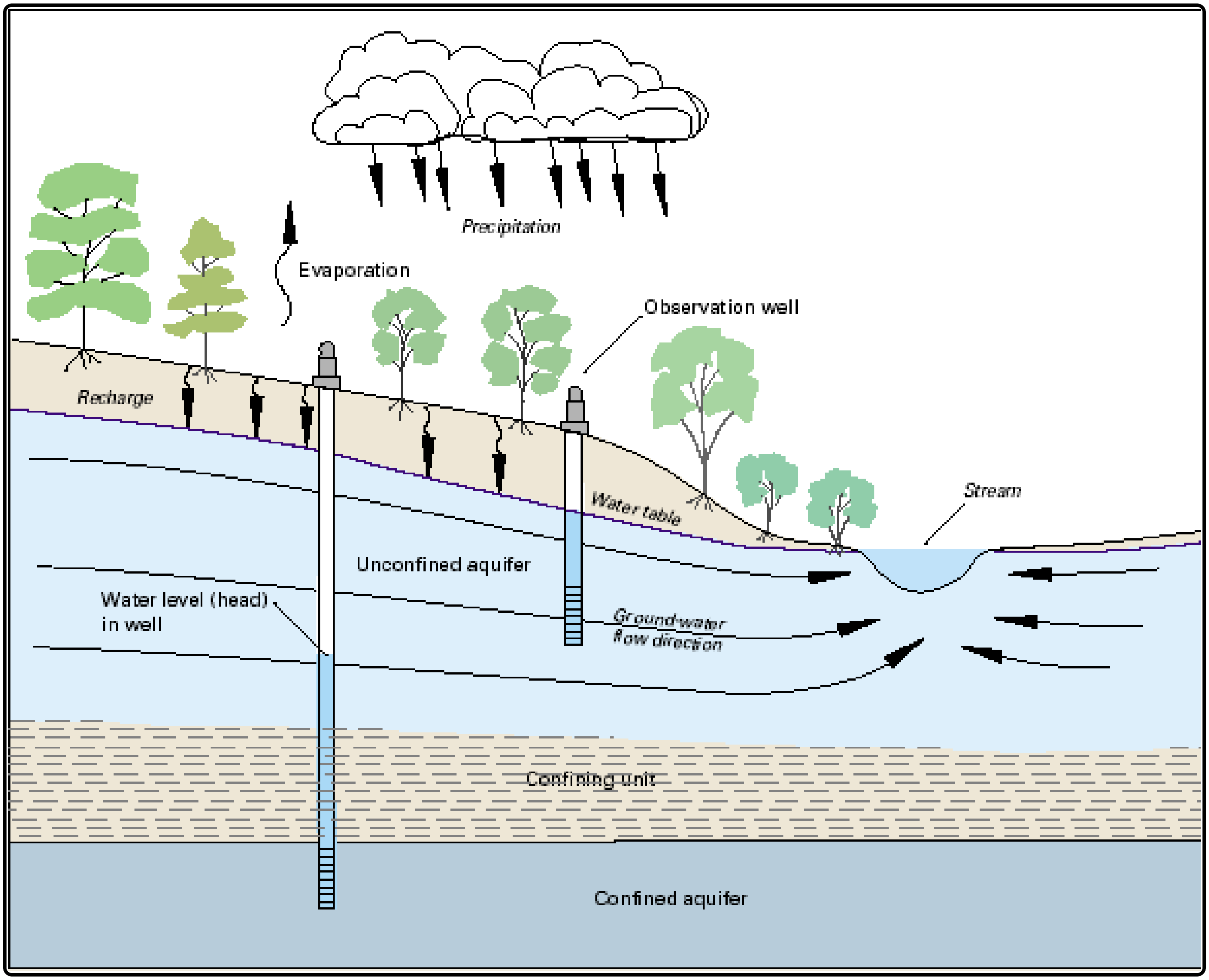
Hydraulic Conductivity (K)

A critical hydrogeologic parameter is hydraulic conductivity, which is the coefficient of proportionality describing the rate at which water can move through a permeable medium. Obtain a site-specific hydraulic conductivity value for all releases with concentrations above Tier I RBSLs that is estimated by aquifer testing (pumping test or slug test) in on-site wells.

Aquifer Testing

Aquifer testing helps characterize the geologic subsurface by estimating a site-specific hydraulic conductivity value and aquifer transmissivity, if necessary. The type of aquifer testing required is dependent on the type of aquifers at the site.

In general, [slug tests] are appropriate for unconfined aquifers while [pump tests] are appropriate for confined aquifers.



Confined and unconfined aquifer conditions

During characterization, carefully characterize hydrogeologic conditions that contribute to an understanding of the hydrogeologic setting, such as perched or confined aquifers, fracture-flow conditions, preferential contaminant or groundwater pathways, anisotropic flow characteristics and macro and micro heterogeneities.)

Use the observed and measured hydrogeologic parameters to calculate an average groundwater flow velocity based on the darcy velocity divided by measured porosity. Compare the calculated groundwater flow rate to the contaminant migration rate based on the measurement of COCs in monitoring wells (or advanced characterization techniques) and the known or estimated time of release.

The US Geological Survey provides additional information on hydrogeologic characteristics.

Understand the subsurface lithology and hydrogeology to determine if a confining unit is present. If a confining layer is present, installation of a monitoring well into the water-bearing unit beneath the confining layer could cause cross-contamination.

Active Remediation Evaluation

If COC concentrations in soil and groundwater at all appropriate assessment locations are below the Tier I RBSLs or Tier II SSTLs, active remediation is not warranted. However, active remediation is required when SCR results indicate any of the following conditions:

- POEs are impacted above Tier I RBSLs or in imminent threat of impact,
- Recoverable LNAPL is present,
- COC concentrations are above SSTLs.

Proceed to the Corrective Action section of this guidance if active remediation is warranted.

Additional Resources

ITRC Accelerated Site Characterization

ITRC Characterization and Remediation in Fractured Rocks

ITRC Direct Push Wells

ITRC Groundwater Statistics and Monitoring Compliance

ITRC Incremental Sampling Methodology

ITRC LNAPL Guidance Update

ITRC Mass Flux and Mass Discharge

ITRC Passive Samplers

ITRC Risk Assessment

ITRC Triad Approach

Light Non Aqueous Phase Liquids (Free Product)

LNAPL (light non-aqueous phase liquid) is an immiscible organic liquid that is less dense than water. Initially, all petroleum releases originate as LNAPL in the form of gasoline, diesel fuel, lube oils or other petroleum products.

LNAPL may represent the greatest mass of contamination in the subsurface from a petroleum release and may also be a source of petroleum vapors to intrude into structures, and an ongoing source of dissolved phase groundwater contaminant plumes. Therefore, it is critical to accurately characterize the spatial distribution of LNAPL to enable LNAPL abatement, remediation, and risk management to protect human health and the environment.

The complex distribution of LNAPL in the subsurface makes assessment and remediation challenging. Recent advances in LNAPL science have improved the understanding of LNAPL behavior in the subsurface. The purpose of this guidance is to apply this improved understanding of LNAPL behavior to adequately characterize LNAPL distribution and identify site-specific LNAPL concerns.

Key Concepts

LNAPL Saturation

LNAPL never occupies 100% of pore spaces; instead it shares the pore spaces with air in the unsaturated zone and water in the saturated zone. Even then, LNAPL does not continuously occupy the pore spaces. The image below depicts LNAPL ganglia sharing pore spaces with water in the absence of soil.

Basic LNAPL concepts and terminology are introduced in the ITRC LNAPL-2 technical guidance document

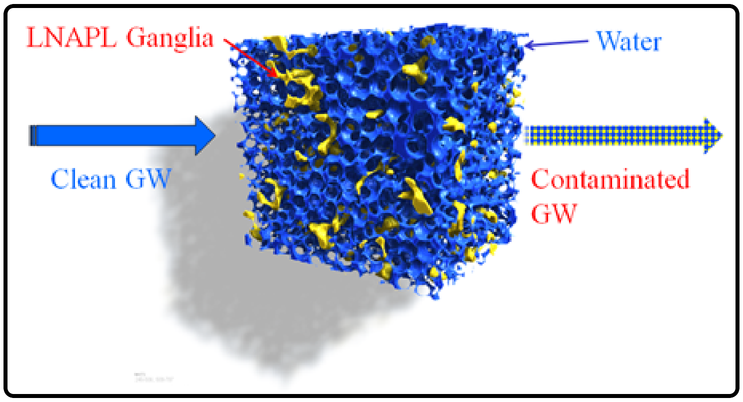


Image from Singh et al. (2011)[1]

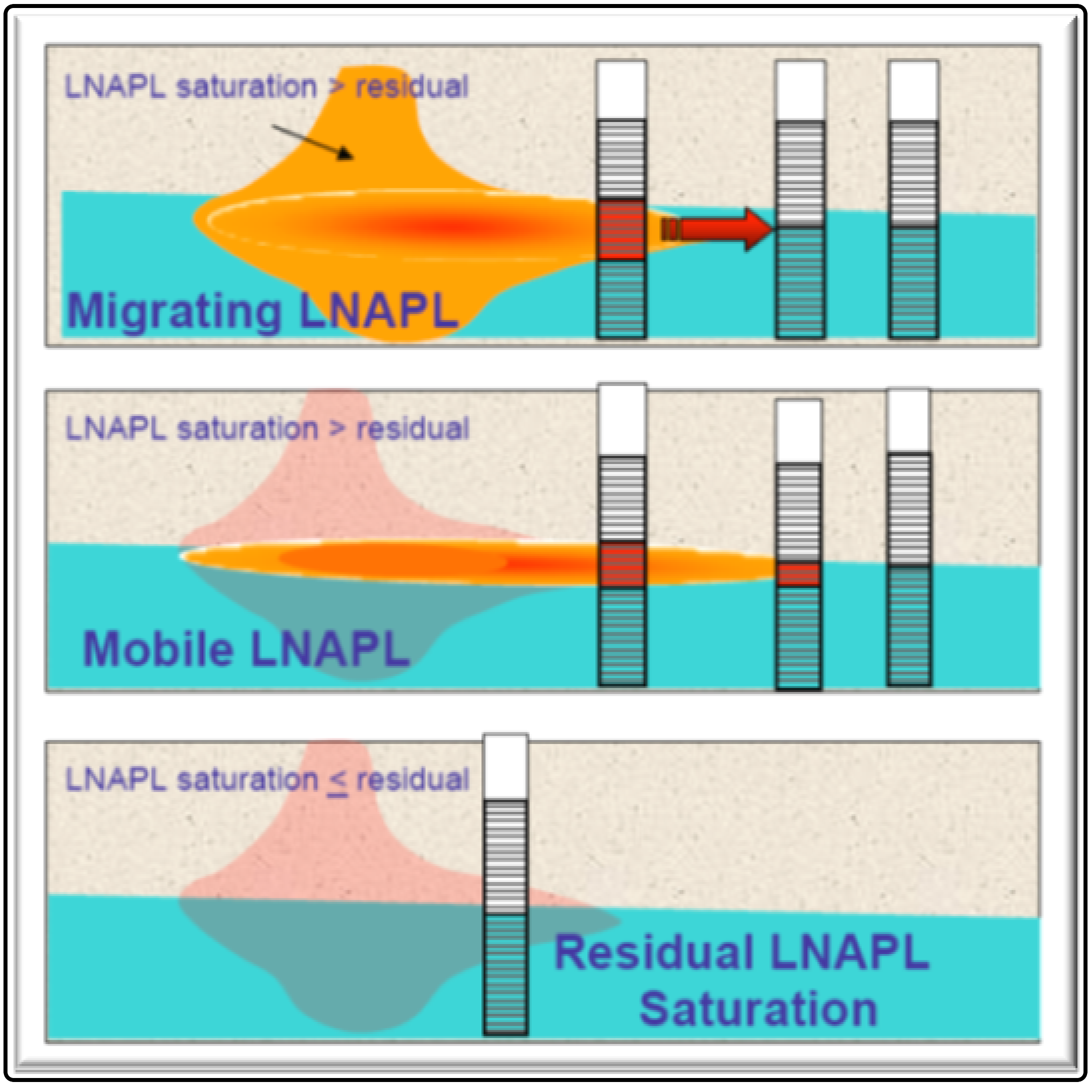
Of particular importance to understand is the difference between residual[2], mobile[3], and migrating[4] LNAPL. The figure below illustrates these three LNAPL saturation conditions.

[1]Singh, K., Niven, R.K., Senden, T.J., Turner, M.L., Sheppard, A.P. & Middleton, J., Knackstedt, M.A. (2011). Remobilization of residual non-aqueous phase liquid in porous media by freeze-thaw cycles. Environmental Science & Technology, 45, 8, 3473-3478. http://pubs.acs.org/doi/abs/10.1021/es200151g

[2]LNAPL saturation is greater than 0 but does not have enough driving head to overcome pore entry pressure

[3]exceeds residual saturation. Mobile LNAPL may appear in a monitoring well.

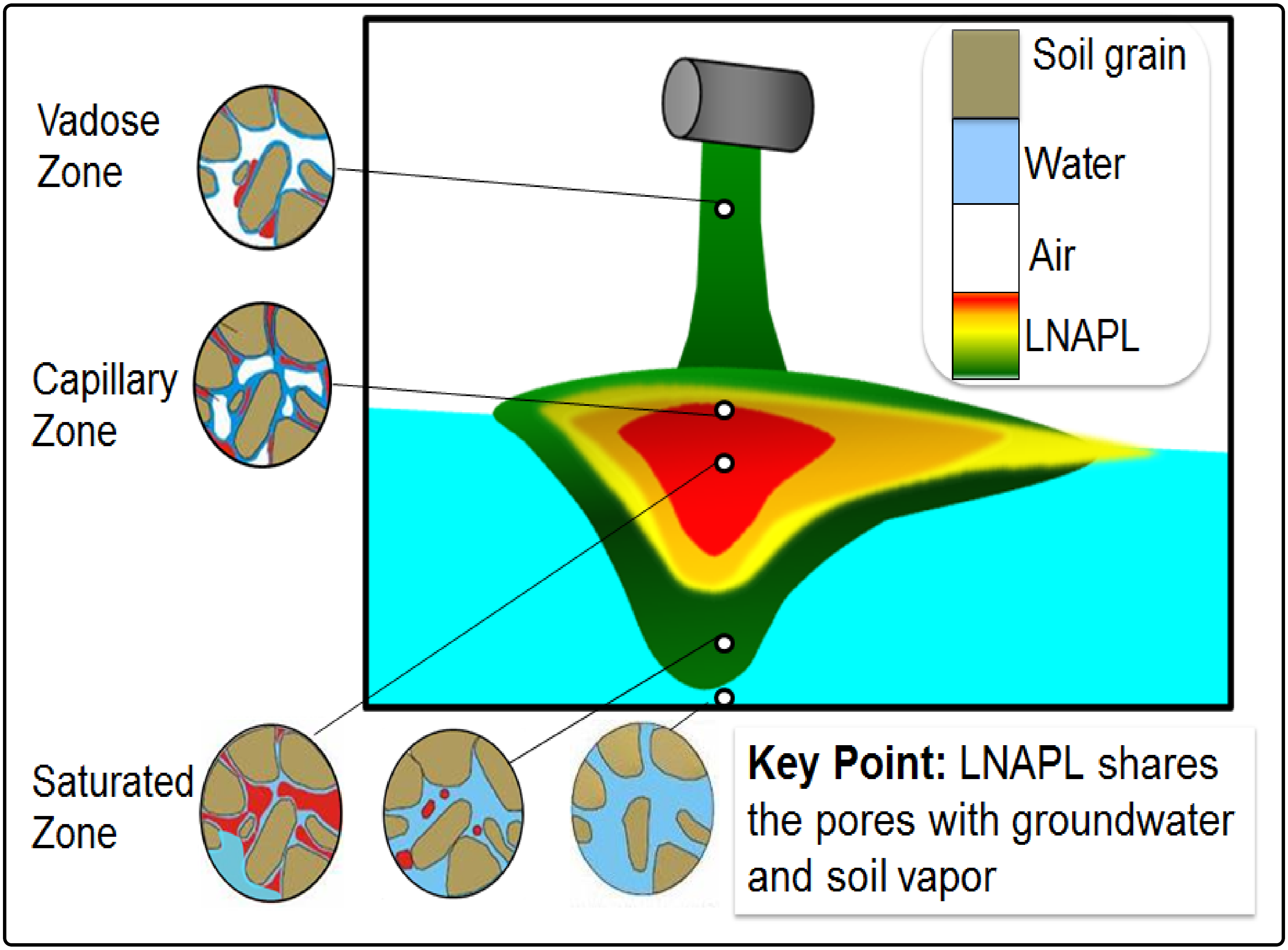
[4]Migrating LNAPL exceeds residual saturation and has enough driving head to continue to overcome pore entry pressure and expand through the subsurface.



LNAPL Saturation (Courtesy of ITRC)

Distribution Model

LNAPL does not simply float on top of the water table. Rather, LNAPL is distributed above, at, and below the water table at saturations that vary vertically and horizontally. The image below is a simplified depiction of LNAPL distribution.



LNAPL Distribution (Courtesy of ITRC)

In-well LNAPL Thickness

The amount of LNAPL in a well is a poor indicator of the vertical and lateral extent of LNAPL, LNAPL volume and recoverability. Measured LNAPL in a well is a clear indicator that mobile and potentially migrating LNAPL is present.

LNAPL Migration/Stability Evaluation

LNAPL migration is controlled by the driving head of the LNAPL and the ability of the LNAPL to overcome pore entry pressure. For a finite release, LNAPL ceases to migrate within a relatively short period of time depending on the magnitude of the release. This is because, among other reasons, the LNAPL gradient dissipates over distance and time and thus the driving head decreases.

Recoverability

Mobile and migrating LNAPL saturations may be recoverable, but residual concentrations are not readily recoverable. Residual range saturations may still need to be considered and addressed, as they could be a continuing source of dissolved and vapor phase impacts.

LCSM

The components of an LCSM (LNAPL Conceptual Site Model) are the same as those identified in the CSM section of guidance. However, additional considerations should be made when developing a CSM where LNAPL is present or believed to be present.

LNAPL Indicators

ASTM Standard Guide 2531 provides further detail on developing a CSM for LNAPL sites.

LNAPL observed in a monitoring well

LNAPL observed in a monitoring well is a direct indicator that LNAPL is present and mobile or potentially migrating.

Dissolved-phase analytical data

Dissolved-phase analytical data may be utilized as an indirect indicator that LNAPL is present. Persistent dissolved-phase analytical data that shows little degradation or change in concentration over time may be an indicator that LNAPL is present in the subsurface. Additionally, dissolved-phase concentrations near the effective solubility of a particular chemical of concern may be an indicator. For example, the effective solubility of benzene is typically stated to range between 9-18 mg/L for unweathered gasoline. Generally, dissolved-phase concentrations of benzene above 1 mg/L may indicate that there is an LNAPL source, depending on the amount of weathering that has occurred and the location of the monitoring point relative to the LNAPL source.

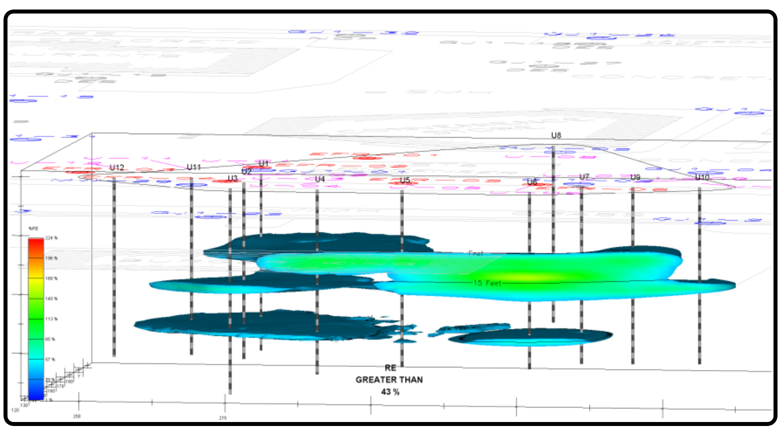
Conventional Soil Assessment Information

Conventional soil data may be utilized as an indirect indicator of LNAPL presence. For this reason, it is important to have continuous core samples, complete boring logs and detailed cross sectional diagrams. It is not recommended by OPS to collect environmental soil data at predetermined intervals.

- In general, high TPH concentrations in soil may be indicative of LNAPL.
- High PID readings, or readings that change abruptly, may also be an indirect indicator of LNAPL.
- Field sheen tests (i.e., shake tests, jar tests) may be used to evaluate the presence of residual LNAPL. Soil samples containing LNAPL can create a hydrocarbon sheen on the water if agitated.

Laser-Induced Fluorescence

LIF (laser-induced fluorescence) can be used as a downhole tool to qualify the distribution of LNAPL in the subsurface. Modeling software can create a 3-dimensional representation of LNAPL, as shown below.



Example of LIF Model

Conceptual Challenges

Understanding and identifying the conceptual challenges presented below are important for understanding LNAPL migration pathways, developing the LCSM and, ultimately, developing an effective LNAPL remedial strategy.

Residual Saturation

It is important to know the distribution of residual LNAPL because it may be a persistent source for groundwater and vapor impacts. Failure to identify residual LNAPL will result in an inaccurate LCSM and delayed progress with cleanup.

Water Table Fluctuations

Water table fluctuations can cause LNAPL to become trapped below the water table. LNAPL trapped below the water table may become mobile and enter monitoring wells with a drop in the water table in unconfined conditions. Water table fluctuations may give the impression that LNAPL is appearing and disappearing as shown in this Video Clip.

Geologic Structure, Lithology and Transport

LNAPL distribution and appearance in monitoring wells will differ based on unconfined versus confined conditions, perched lenses and fractured pathways. A gross understanding of the geologic stratigraphy is essential. However, LNAPL transport is often controlled by microscopic characteristics of the soils, so details such as grain size, sorting, veining/fractures and microbedding should be noted.

Questions to ask when LNAPL is present in a monitoring well

- Is the source of this LNAPL known?
- Is the route of transport understood?
- Is the vertical and horizontal distribution of LNAPL understood?

● Is the location of the monitoring well in the right place to answer these questions?

● Does the LCSM need to be updated?

Utilization of High Resolution Site Characterization

OPS recommends the utilization of high-resolution site characterization to enhance the LCSM when appropriate. These tools assist in understanding the distribution and magnitude of the LNAPL in the subsurface and ultimately may be used to identify the concerns and remedial objectives associated with LNAPL.

LNAPL Transmissivity

LNAPL transmissivity (Tn) is an indicator of the ability of a formation to transmit LNAPL. Tn values are used to assess LNAPL migration and recoverability and are obtained from LNAPL recovery/recharge tests and analysis. Tn values can vary spatially and temporally at a release site.

OPS recommends consideration of Tn baildown testing when in-well LNAPL thickness is > six inches. The number of tests and the number of locations are dependent on the spatial and temporal understanding of LNAPL distribution. Generally, tests should be completed during a period of low groundwater elevation.

Tn tests should be conducted per ASTM Standard Guide 2856. An instructional video for conducting an LNAPL baildown test can be viewed at the following link (courtesy of the American Petroleum Institute).

The following guides, workbooks and articles provide additional information on LNAPL transmissivity:

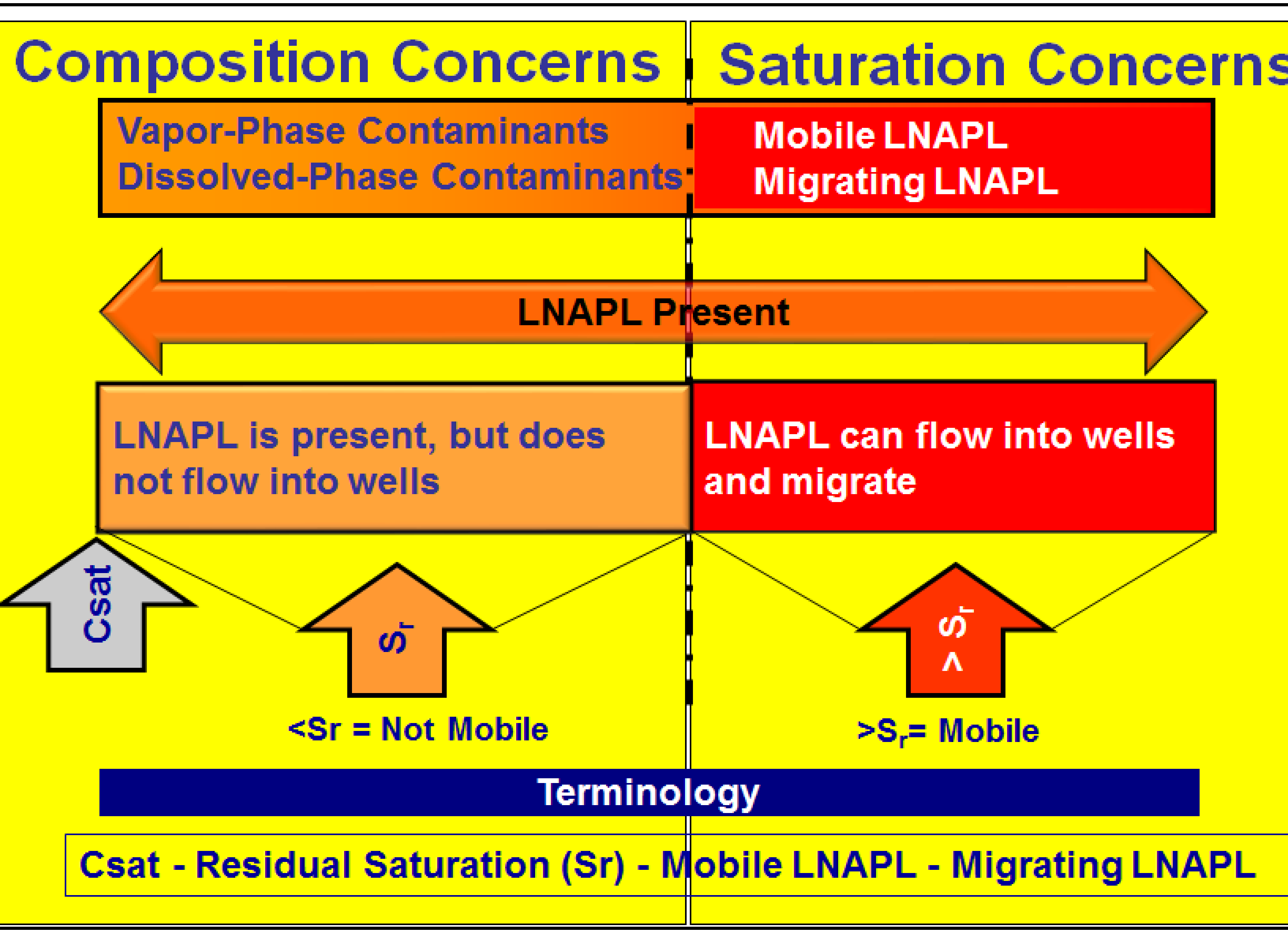
- ASTM Standard Guide 2856 LNAPL transmissivity.
- API LNAPL Transmissivity Workbook LNAPL transmissivity tool.
- LUSTLine Articles

Baildown Test Video

ITRC has proposed that LNAPL recovery is practical when Tn is above the range of 0.1 to 0.8 ft2/day.

LNAPL Concerns

LNAPL concerns are either saturation-based or composition-based as illustrated in the figure.



Courtesy of ITRC

Saturation-based concerns mean that the LNAPL saturation is greater than residual saturation. The primary saturation-based concern is the potential for

LNAPL migration. Recoverability should be evaluated by LNAPL transmissivity testing.

Composition-based concerns include dissolved-phase and vapor-phase exposure. Residual LNAPL saturation may need to be reduced to abate these concerns.

OPS Policies

Based on our improved understanding of LNAPL distribution, characteristics and concerns, OPS has developed the following policies:

- OPS has adopted a range of Tn < 0.1 to 0.8 ft2/day, with consideration given to spatial and temporal understanding. LNAPL saturation objectives should be addressed until Tn values are below the range.
- When recovery is negligible, focus on compositional concern to achieve closure.
- Release Events can be closed with measurable LNAPL if there are no compositional concerns and the LNAPL recovery is negligible.

Additional Resources

[ASTM Standard Guide for Development of Conceptual Site Models and Remediation Strategies for LNAPL Subsurface Releases]

[Evaluating LNAPL Remedial Technologies]

[Evaluating Natural Source Zone Depletion at Sites with LNAPL]

[API LNAPL Distribution and Recovery Model]

[API Interactive LNAPL Guide Version 2.0.4]

[API LNAPL Transmissivity Workbook: A Tool for Baildown Test Analysis]

[ASTM Standard Guide for Estimation of LNAPL Transmissivity]

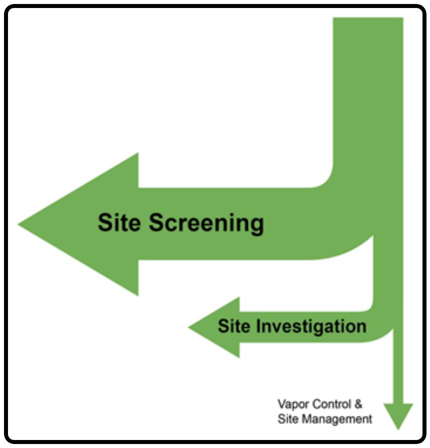
Petroleum Vapor Intrusion

Petroleum Vapor Intrusion (PVI) refers to the process by which petroleum vapors may originate from petroleum-contaminated groundwater, soil, or LNAPL and diffuse through vadose zone soil or preferential pathways into areas of concern, such as utility corridors or structures. This OPS assessment guidance provides a process for screening, investigating and evaluating PVI to be protective of human health and the environment.

This assessment guidance should not be used in emergency situations; responses to emergency situations should be addressed by the Emergency Response section of this guidance.

Recent advances in PVI science have lead to an improved understanding of petroleum vapor migration, biodegradation, assessment and mitigation. Most relevant to these advancements are multi-stepped processes developed by ITRC and EPA.

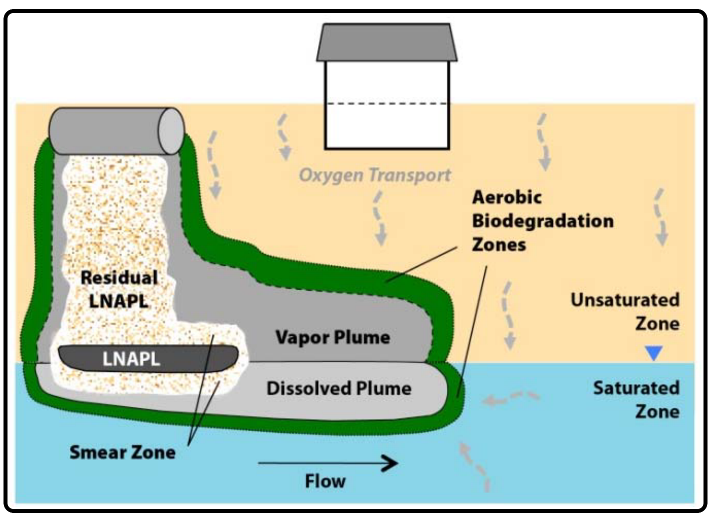
By utilizing this process, the vapor pathway can often be safely eliminated early in the assessment phase, allowing necessary resources to be utilized on the small number of releases that require petroleum vapor mitigation. The image below (courtesy of ITRC) depicts the relative ratio of sites where the vapor pathway is eliminated by site screening versus site investigation using the guidance developed by ITRC and adopted by OPS.



Relative ratio of sites requiring Site Investigation and Mitigation based on Site Screening process (ITRC, 2014).

PVI 101

Biodegradation is a naturally-occurring process where chemicals are broken down by microorganisms. Fortunately, petroleum vapors are attenuated relatively quickly in vadose zone soils by aerobic biodegradation. The generalized concept is depicted in the image below (courtesy of EPA).



Schematic depiction of the biodegradation process for petroleum hydrocarbons (EPA, 2015).

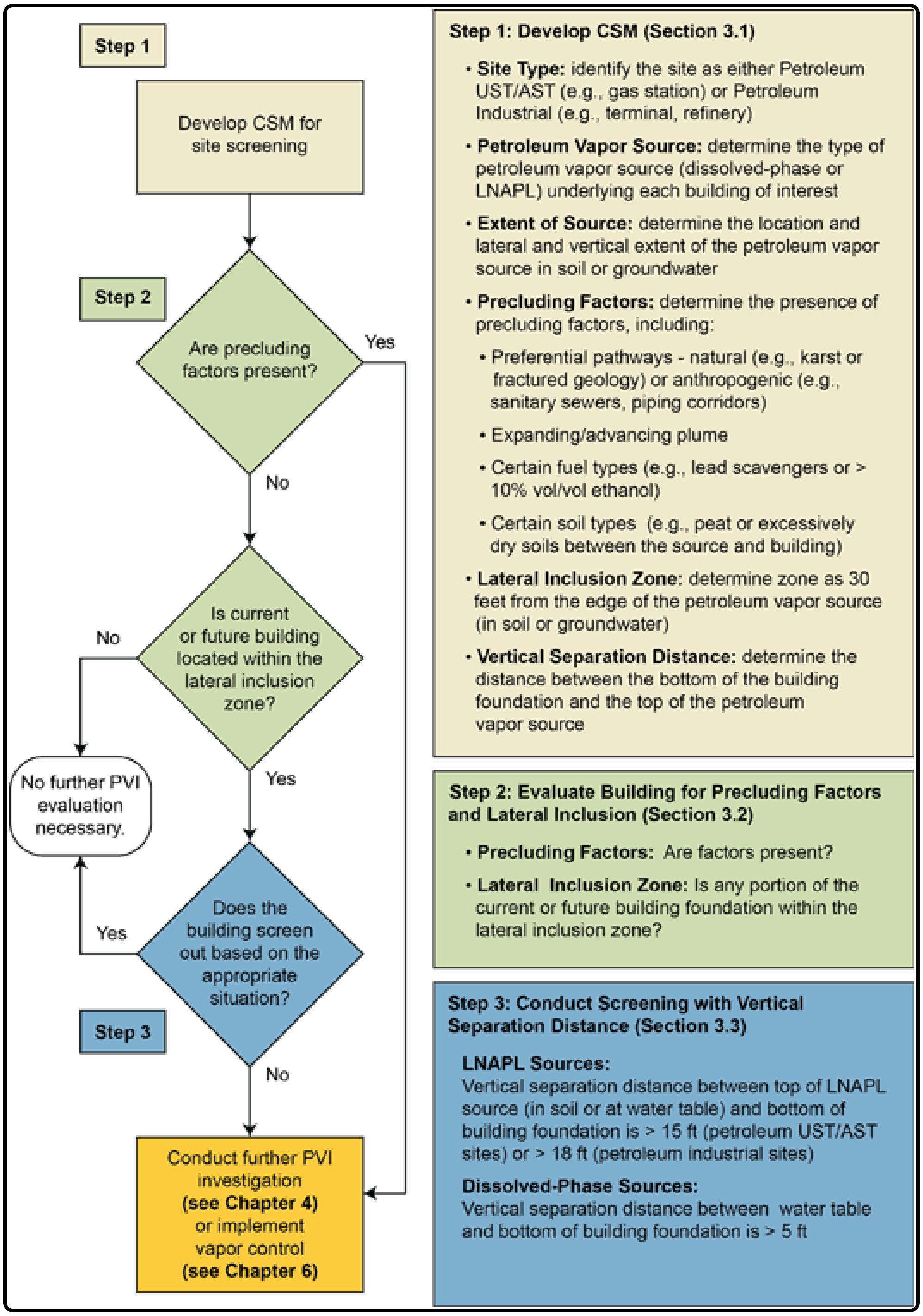
Previous PVI assessment did not account for biodegradation in the vadose zone. An understanding of the role biodegradation plays in petroleum vapor attenuation and migration lays the foundation for the remainder of our PVI guidance.

PVI Site Screening

The first step of the PVI assessment strategy developed by ITRC is to screen the site for certain conditions. The three-step site screening process includes:

1. Developing a preliminary conceptual site model (CSM).
2. Evaluating nearby structures for precluding factors and lateral inclusion.
3. Conducting screening of nearby structures based on vertical separation distance.

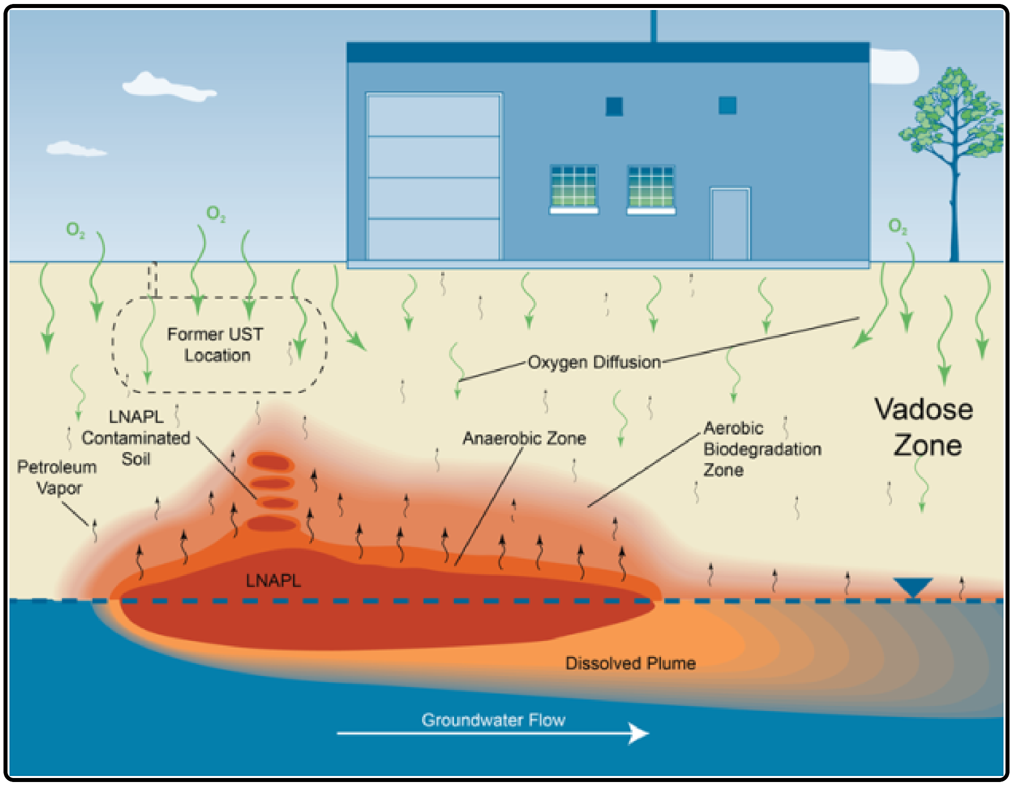
The figure below depicts the PVI site screening process.



Flow chart of the PVI Site Screening Process (ITRC, 2014).

Conceptual Site Model (CSM)

The CSM integrates all site data and information to depict contaminant distributions in each phase (LNAPL, sorbed, dissolved and vapor) as illustrated in the figure below.



Generalized CSM for conducting the PVI site screening process (ITRC, 2014).

The CSM must include the following critical elements for effective PVI screening.

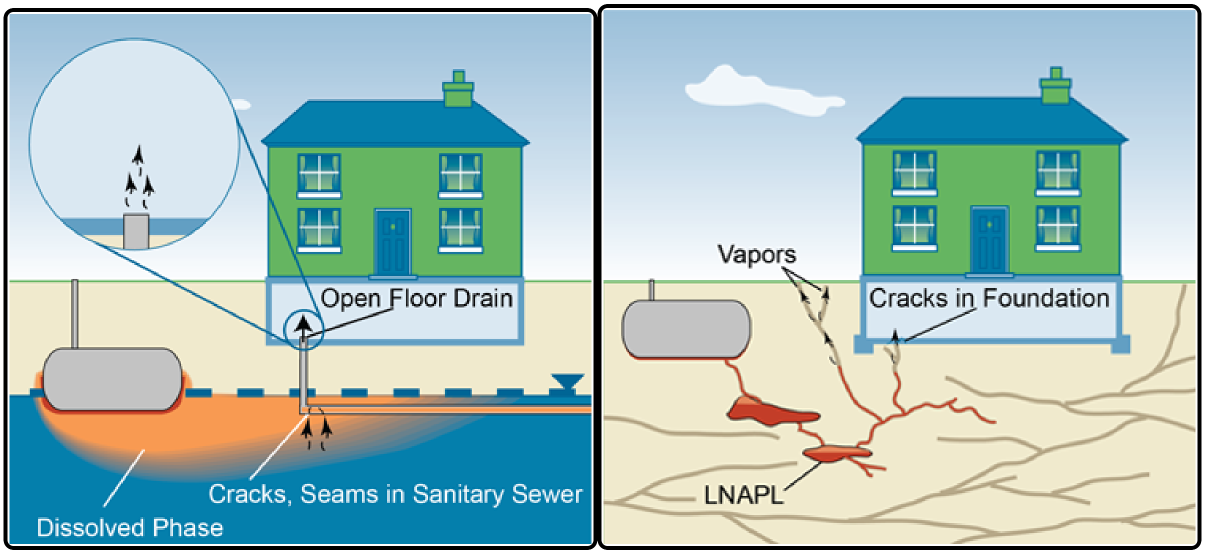
- Vapor source (LNAPL or dissolved-phase plume)
- Extent of contamination
- Precluding factors
- Lateral inclusion zone
- Vertical screening distance

The CSM should be continually updated and refined as new information, such as soil and groundwater data, becomes available. Appendix D of the ITRC PVI guidance document includes a checklist that can aid in the development of the PVI CSM.

Precluding Factors

Precluding factors can be man-made or naturally-occurring and include the following:

- Preferential transport pathways that may connect vapor sources (LNAPL or dissolved) with receptors
- Man-made precluding factors include:
- Utility corridors
- Trenches
- Elevator pits
- Basement sumps
- Drainage pits
- Backfill with a greater porosity than the surrounding native material
- Natural precluding factors include:
- Gravel lenses and channels
- Karst
- Bedding planes
- Secondary porosity openings in bedrock
- Ongoing petroleum releases with expanding contaminant boundaries, as the lateral inclusion zone cannot be identified



Examples of manmade and naturally-occurring precluding factors (ITRC, 2014).

Precluding factors must be evaluated for and identified in the PVI screening process and would result in moving on to the Site Investigation phase if confirmed.

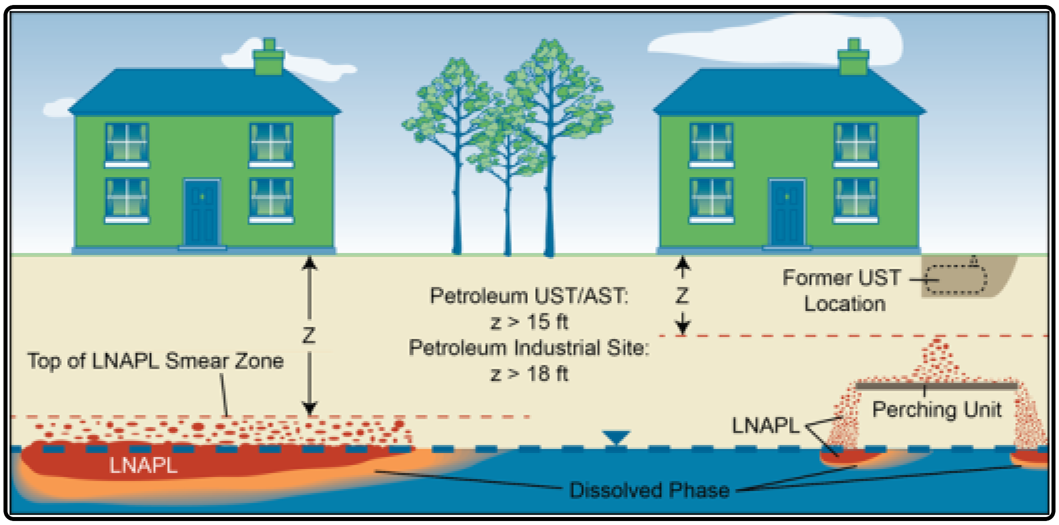
Lateral Inclusion

The lateral inclusion zone is defined as the horizontal distance from the edge of a petroleum vapor source (LNAPL, sorbed-phase soils or dissolved-phase groundwater) to the edge of a building foundation. A minimum lateral inclusion zone of 30 feet has been established by ITRC and will also apply to releases from regulated storage tank systems in Colorado. The Tier I RBSL for the groundwater indoor air inhalation exposure pathway of 0.016 mg/L should be utilized to establish the lateral inclusion zone for dissolved-phase vapor sources.

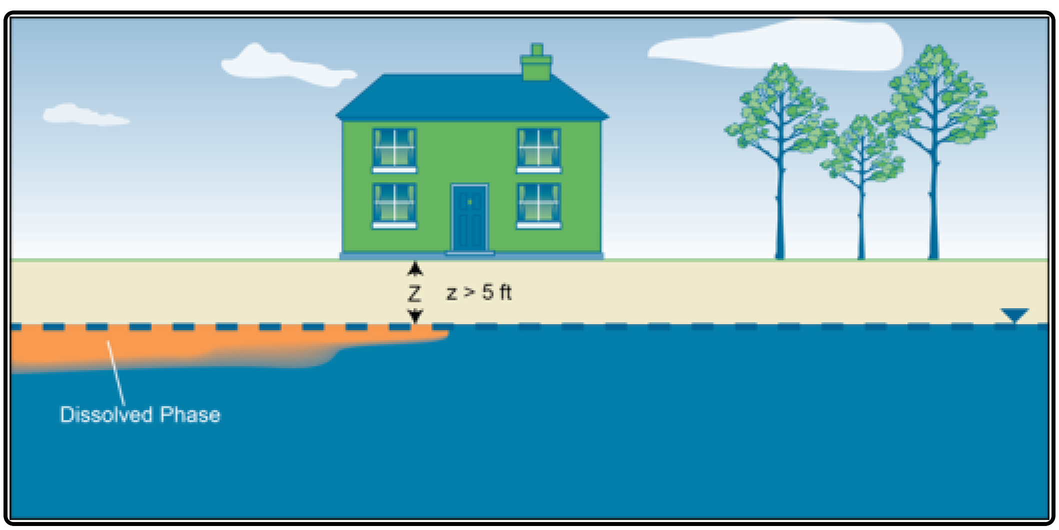
All structures within 30 feet of the petroleum vapor source must be identified and further evaluated in the screening process. Buildings located beyond 30 feet of the petroleum vapor source do not need additional evaluation and can be screened out. Buildings associated with the dispensing of petroleum are not considered for PVI. The PVI exposure pathway can be eliminated if there are no precluding factors or buildings identified within 30 lateral feet of the vapor source.

Vertical Screening

Vertical screening is the process used to determine if the vapor exposure pathway can be eliminated from a petroleum release event by applying the appropriate vertical screening distances to the CSM. The vertical separation distance is defined as the the minimum thickness of soil between the top of a petroleum vapor source and the bottom of a building foundation to effectively biodegrade hydrocarbons below a level of concern for PVI. As shown in the figures below, the vertical screening distances for LNAPL and dissolved-phase sources based on several empirical studies and adopted by OPS are 15 feet for LNAPL and five feet for dissolved-phase vapor sources.



Vertical screening distance is 15 feet for LNAPL vapor sources (ITRC, 2014).



Vertical screening distance is five feet for dissolved vapor sources (ITRC, 2014).

It is important to note that LNAPL does not need to be present in a monitoring well to warrant evaluation of an LNAPL source. LNAPL may exist in the residual saturation range and should be evaluated accordingly LNAPL indicators.

A structure can be screened out when the building foundation within the lateral inclusion zone is greater than the vertical screening distance from the vapor source. Conversely, site investigation (e.g., soil vapor sampling, fate and transport modeling and indoor air sampling) must occur if a building foundation is less than the vertical screening distance from the vapor source.

Site Investigation

When a structure is not screened out by the PVI site-screening process, additional site investigation is required to evaluate whether the vapor exposure pathway is complete. The two primary PVI investigative approaches are the collection and analysis of either soil gas or indoor air samples. If possible, soil gas sampling should generally be conducted prior to indoor air sampling. However, indoor air sampling may be conducted as the first step of site investigation based on potential receptor concerns.

Community Engagement

Property owners of structures that require PVI site investigation must be identified and notified prior to proceeding with any site investigation activities. Community engagement should be conducted to address potential concerns and questions that may arise. The Community Engagement Section and Community Engagement Fact Sheets in Appendix K of the ITRC PVI Guidance may be utilized in this effort.

Soil Gas Sampling

Soil gas sampling is recommended as the first step of a PVI investigation if the contaminant sources are not in direct contact with a structure. The initial criteria to apply when determining where to collect soil gas samples for PVI assessments are the location of the contamination source relative to the building, the depth and type of the contamination source (i.e., LNAPL vs. dissolved) and the type and construction of the building (e.g., slab-on-grade construction vs. basement foundation). There are multiple sampling methods that may be utilized to collect soil gas samples, and they can be collected from locations outside the structure or from locations inside the building, such as subslab samples.

Exterior Soil Gas Samples

Appendix G.10 of the ITRC PVI Guidance provides a detailed summary of appropriate soil gas probe materials and construction techniques, sample collection methods and sample containers. A sufficient number of lateral and vertical exterior soil gas samples should be collected at locations as close as possible to the structure within the lateral inclusion zone of the identified vapor source. Sample locations should be based on the CSM and the location of the contaminant source to the structure, both spatially and vertically.

The two techniques most commonly used to install soil gas probes to collect external active soil gas samples are:

- Driven probe rod
- Burial of soil gas sampling tubes

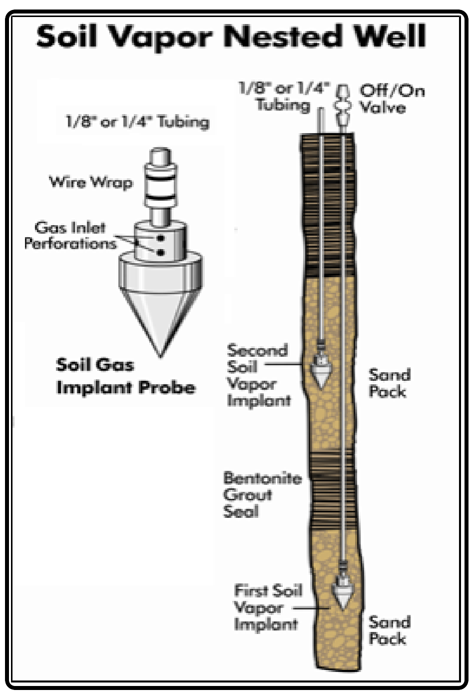
Both methods have been shown to give reliable, reproducible data in moderate-to-high permeability soils.

Vertical soil gas profiles can be developed by installing either multiple nested soil gas probes at a range of depths in a single boring or discrete soil gas points at different depths in separate borings. Ideally, the deepest soil vapor sample point should be installed near the top of the vapor source and the shallowest sample point should be installed near the depth of the building foundation. If the structure is slab-on-grade construction, samples may only need to be collected at a single depth between the top of the vapor source and the depth of the building slab.

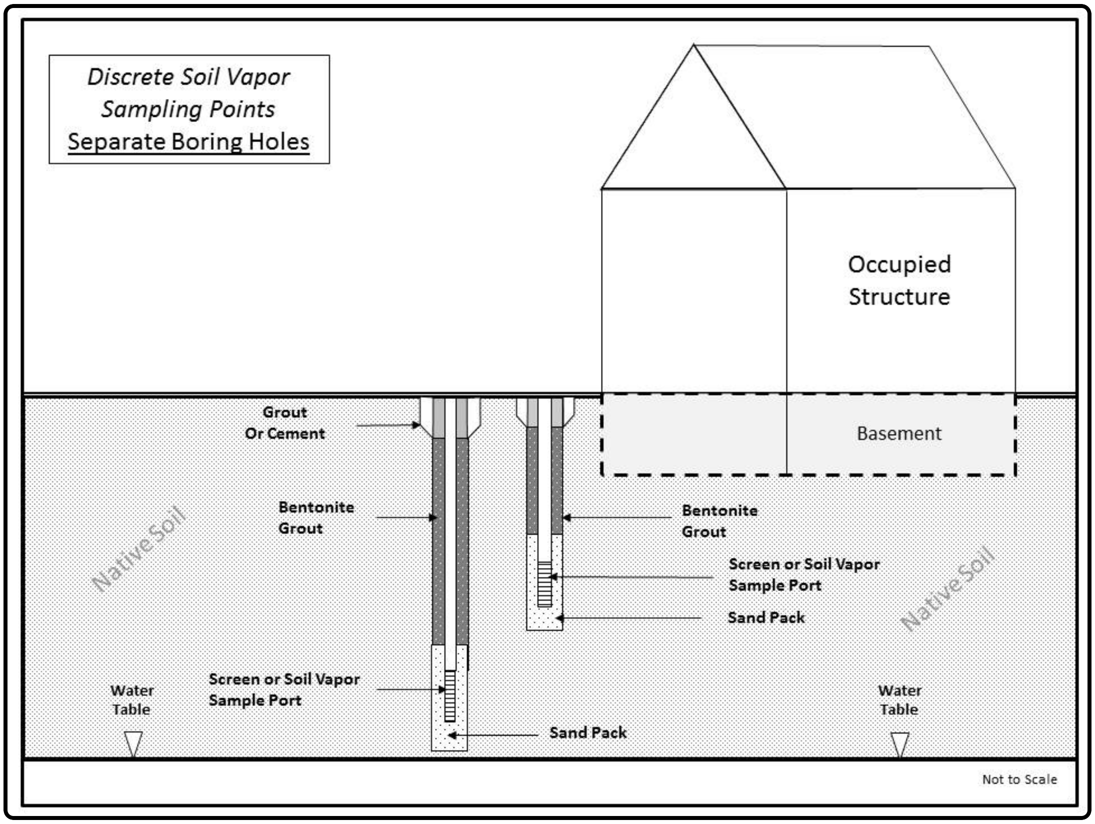
A common problem of soil gas sampling is atmospheric short-circuiting, which leads to erroneous soil gas results. To prevent short-circuiting, the following best management practices have been identified.

- Soil gas probes should be sealed above the sampling zone with a bentonite slurry to prevent outdoor air infiltration.
- For multiple probe depths, the borehole should be grouted with dry and hydrated bentonite between probes to create discrete sampling zones or separate nested probes should be installed.
- Set a protective casing around the top of the probe tubing and grout in place to the top of the bentonite; slope the ground surface to direct water away from the borehole.

To reduce the risk of short-circuiting, discrete vapor points may be installed instead of nested points. Examples of nested and discrete soil vapor points are depicted in the figures below.



Nested soil vapor well (ITRC, 2014).

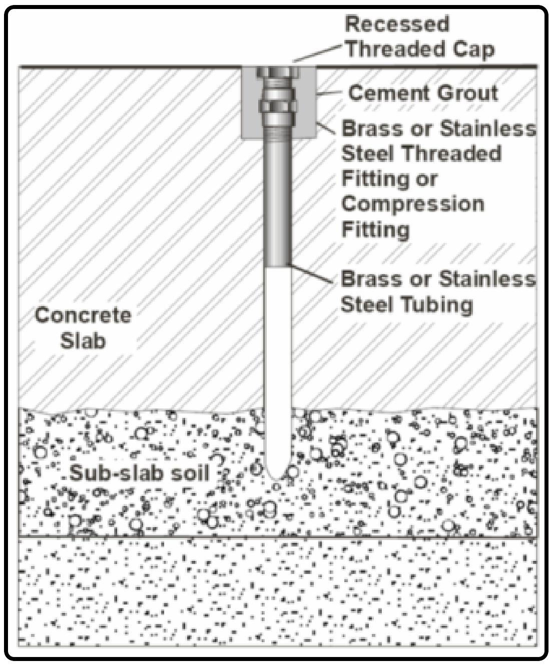


Subslab Soil Gas Samples

Subslab samples refer to soil gas samples collected from immediately below a slab on grade or a basement floor slab. The procedure involves drilling through the concrete slab and collecting a soil gas sample for laboratory analysis. When appropriate, subslab soil gas samples may be collected concurrently with indoor air samples so that the subslab concentrations can be directly compared to indoor air concentrations.

If contamination uniformly underlies the structure, such as a dissolved groundwater plume, the subslab sample is typically located near the center of the structure away from the edges of the foundation. If the contamination is located laterally away from the structure, such as in a tank pit or beneath a dispenser island, the subslab sample should be located toward the side of the structure facing the contamination. In practice, however, the location of subslab samples is determined more by access and floor coverings than it is by the location of the contamination.

A standard operating procedure for subslab sampling was published by EPA in March 2006. There is also a standard operating procedure in the EPRI handbook. A generalized schematic diagram of a subslab soil gas probe is depicted below.



Typical subslab vapor probe installation (EPA 2006).

Additional information on subslab soil gas sampling is provided in Appendix G.11 of the ITRC PVI Guidance.

Soil Gas Sample Containers and Laboratory Analysis

Soil gas samples may be collected in stainless steel Summa canisters, gas-tight vials (glass or stainless steel) or tedlar bags. Summa canisters and gas-tight vials are recommended over Tedlar bags. Tedlar bags are not considered to be reliable for more than 48 hours, as they are subjected to changes in ambient pressure, and thus, they should not be shipped by air for laboratory analysis. Glass vials are recommended over stainless steel canisters because water is visible, which can be problematic to laboratory instrumentation.

Soil gas samples should be analyzed for benzene by EPA Method TO-15.

Soil Gas Sample Data Evaluation

Benzene soil gas sample results should be compared to the soil vapor to indoor air RBSL of 2,900 µg/m^3. Indoor air sampling should be conducted when soil gas concentrations exceed the RBSL in the shallowest collected interval for exterior or subslab samples. Sites where soil gas concentrations exceed the RBSL in deep or intermediate sampling intervals but not in the shallow sampling interval may require additional monitoring prior to considering indoor air sampling or soil vapor pathway elimination.

Indoor Air Sampling

Indoor air sampling is recommended to investigate the vapor intrusion pathway if any of the following conditions occur.

- Soil gas sampling results cannot eliminate the indoor air exposure pathway.
- The vapor contaminant source is in direct contact with a structure.
- Potential receptor concerns justify such an action.

Indoor air data represent the sum of sources that contribute contaminants to indoor air. These sources may include indoor sources (e.g., household products or cars in an attached garage), ambient outdoor air and/or the contribution from subsurface sources (i.e., PVI). Interpretation of indoor air data can be complicated when the data are collected without careful planning and well-documented execution. It is critical to conduct a building survey in advance of indoor air sampling to identify potential background sources. Appendix G Indoor Air Questionnaire of the 2007 ITRC Vapor Intrusion Guidance (or a similarly-developed form) must be utilized if indoor air samples will be collected for analysis.

Removing the identified background sources (to the maximum extent practicable) before the sampling begins may be prudent, but be aware that additional, unidentified background sources may remain. A building survey provides an opportunity to educate occupants on what to expect during the sampling event and inform them of the activities that should be avoided immediately before and during the sampling period.

When indoor air is sampled, concurrent outdoor ambient air samples should also be collected at locations upwind of the building being investigated. Similar to a building survey for indoor sampling, information should be documented for outdoor petroleum sources, including:

- Gasoline stations
- Automobiles
- Gasoline-powered engines
- Fuel and oil storage tanks
- Locations that may generate significant petroleum vapors

This information is important for selecting ambient sample locations and interpreting ambient analytical data. Consideration should also be given to other sampling factors that may impact analytical results, including season (summer vs. winter), time of day and weather conditions.

Indoor Air Sample Containers and Analysis

Indoor air samples should be collected in either 3.2-liter or 6.0-liter stainless steel Summa canisters. The sample canister should be placed in the breathing zone three to five feet off the floor in high-use areas. If small children occupy a particular area or room within the structure, a sample canister should be placed on the floor. Areas where sample canister deployment should be avoided are high-traffic areas where the canister may be disturbed and areas near doors, windows and vents. For multi-storied residential structures, one sample should be collected in the basement level or on the first floor for slab-on-grade construction. An eight-hour indoor air sampling period is appropriate for commercial buildings, while a 24-hour sampling interval should be used for residential structures.

Indoor air samples should be analyzed for benzene by EPA Method TO-15.

Indoor Air Data Evaluation

Indoor air analytical results should be compared to the CDPHE (Colorado Department of Public Health and Environment) Air Screening Concentrations Table. The table below is excerpted from the Air Screening Concentrations Table.

Application of Screening Levels for Carcinogens
Example of Benzene

Risk Range	Action Required	Residential Use Air ($\mu g/m^3$)	Worker Use Air ($\mu g/m^3$)
Less than or equal to $1x10^{-6}$ or background	No Further Action, measures to reduce PCE concentrations in air not required	$\leq$ 0.36	$\leq$ 1.6
Between $1x10^{-6}$ and $1x10^{-5}$	Provided soil and/or ground water contamination is being remediated as approved by the Department, continued monitoring of indoor air is likely unnecessary.	0.36 to 3.6	1.6 to 16
Greater than $1x10^{-5}$	Further study needed to determine whether or not the source is from subsurface releases. Mitigation is required it is determined that the vapors are derived from a subsurface source.	> 3.6	> 16

Indoor air values should be compared to the residential or worker action level standards identified in the Air Screening Concentrations Table. Concentrations identified above the action level standards will require further study to determine whether the source is from subsurface vapor intrusion.

Is Additional Investigation Warranted?

The CSM should be updated following the collection and evaluation of data gathered during the petroleum vapor site investigation.

Some questions to consider include:

- Have the vapor sources been properly identified and delineated?
- Has the potential that PVI possibly affected buildings been investigated?
- Has sufficient data been collected to reach a PVI pathway conclusion for the release?

Additional data gathering should be considered if data gaps are identified in this step.

Is Active Remediation Warranted?

Once it has been determined that sufficient soil gas or indoor air data have been collected, the final step of the site investigation is to determine whether the vapor pathway is complete. If the pathway is determined to be incomplete, the vapor pathway can be eliminated and no further vapor investigation is necessary. However, if the pathway is determined to be complete, vapor mitigation or corrective actions must be considered.

Corrective Action

A CAP (corrective action plan) is required when the results of an SCR (site characterization report) identify that remediation is necessary to abate the concerns associated with a release. The CAP section of this guidance is divided into three sections: CAP Preparation, CAP Technologies, and CAP Implementation.

CAP Preparation

Identify Contaminant Concerns

The first step in developing a CAP is to identify the specific contaminant concerns associated with the release. There are four distinct contaminant phases that need to must be evaluated:

- Sorbed phase
- LNAPL (free phase)
- Dissolved phase
- Vapor phase

Each contaminant phase has potential concerns that must be reviewed and identified for a release. Specific contaminant concerns are identified in the table in the following section.

Define Remedial Goals and Objectives

Remedial goals and associated objectives should be clearly defined based on the identified contaminant concern. Remediation goals are the desired condition to be achieved by the remedial strategy or action that constitutes the end of management for a specific concern. A remediation objective describes how the remediation goal will be accomplished and is established in order to select the technology(ies).

The table below identifies potential contaminant concerns for each phase with appropriate remedial objectives for each concern. A particular release event requiring active remediation will likely have multiple contaminant concerns and associated remedial objectives.

CORRECTIVE ACTION CONTAMINANT CONCERNS AND REMEDIAL OBJECTIVES IDENTIFICATION TABLE								
Contaminant Phase	Contaminant Concern	Is this concern present?	Remedial Objective	Treatment Area Identified?	Contaminant Mass Estimate (kg)		Proposed Remedial Option	Treatment Train Phase
					TPH	Benzene		
Sorbed	Surficial soils impacted above Tier I RBSLs and surface is not covered by an impervious material		Remove or reduce surficial soil impacts to below Tier I RBSLs					
	Vadose zone soil impacted above Tier I RBSLs and/or Tier II SSTLs and groundwater is impacted or potentially impacted		Remove or reduce vadose zone soil impacts to below Tier I RBSLs and/or Tier II SSTLs					
	Vadose zone soil impacted below Tier I RBSLs but groundwater impacted above Tier I RBSLs		Remove or reduce vadose zone mass to address contribution to groundwater					
	Smear zone or saturated soil impacted and contributing to groundwater contaminant migration		Reduce mass in smear zone and/or saturated soil to address contribution to groundwater					
LNAPL	LNAPL is migrating		Terminate LNAPL mass migration by mass recovery or mass control					
	LNAPL saturation is above residual saturation (mobile) and transmissivity is above the recoverable range		Recover LNAPL to the MEP (transmissivity range)					
	LNAPL saturation is within the residual saturation range and a persistent source of dissolved phase or vapor phase concerns		Identify appropriate phase change technology or excavate					
Dissolved	Impacted groundwater above Tier I RBSLs offsite and/or SSTLs onsite		Reduce groundwater concentrations to below Tier I RBSLs offsite and at POCs and to below Tier II SSTLs onsite					
			Remove or address source material contributing to groundwater impact					
	Domestic, irrigation, or water supply well impacted or potentially impacted above Tier I RBSLs		Identify alternate water supply source					
			Modify the well intake					
			Reduce incoming groundwater concentrations to below Tier I RBSLs					
			Engineered control to eliminate exposure to the receptor					
	Surficial water, springs, or sensitive environment POEs impacted		Reduce concentrations to below Tier I RBSLs at property boundary and offsite or Tier II SSTLs onsite					
			Implement measures to protect POEs from further impact					
	Impacted groundwater has intercepted a utility corridor		Evaluate and mitigate migration potential and exposure to receptors					
			Evaluate and mitigate utility worker safety concerns					
Vapor	Petroleum vapor intrusion is impacting a utility corridor and/or structure		Remediate source (LNAPL, sorbed, dissolved) to eliminate impacts		N/A	N/A		
			Engineered controls to prevent PVI		N/A	N/A		

Combined with performance metrics and a remedial endpoint, the remedial objective becomes a SMART Objective (specific, measurable, agreed-upon, realistic, and time-based). A SMART Objective should be developed for each identified remediation goal. SMART is an acronym that is used to guide your goal setting. As it relates to remediation, each SMART objective should include the following components:

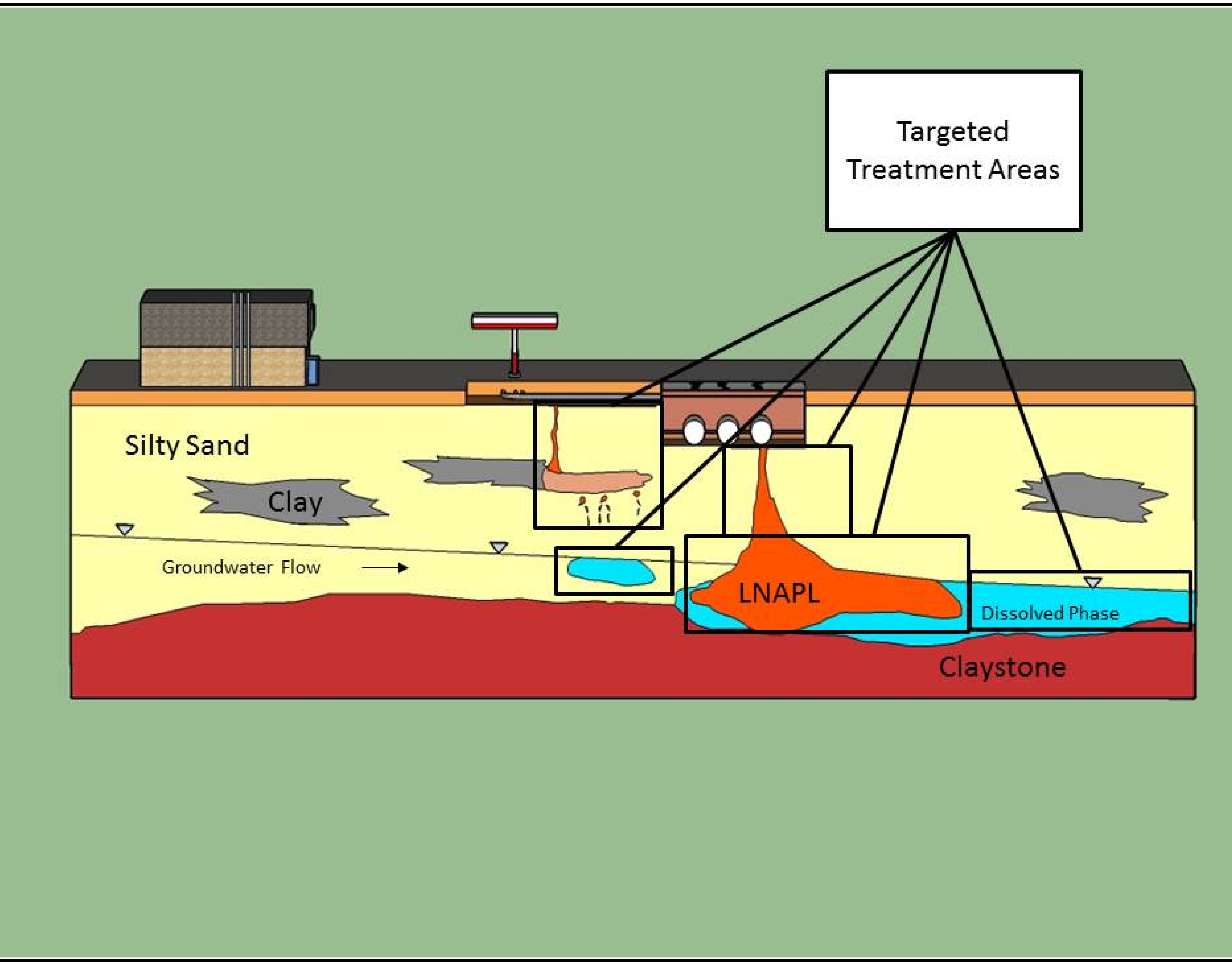
- Specific - The targeted treatment area and technology-specific endpoints are clearly stated.

- Measurable - Performance metrics that demonstrate progress toward the endpoint are clearly stated. Typically, multiple performance metrics are identified to reflect the multi-phase distribution of contaminants.
- Agreed Upon - The concerns, goals, objectives, targeted treatment areas, performance metrics, and endpoints are understood by all interested parties.
- Realistic - The selected technology has a demonstrated ability to achieve the SMART objective and the basis of technology selection is presented.
- Time-Based - The target date for when the technology-specific endpoint is projected to be achieved is clearly stated. Performance milestone, when appropriate, are identified.

It is important to understand that technology specific end points do not necessarily eliminate the environmental concerns derived from the CSM. Technology specific endpoints appropriately account for the expectations of the technology. Combined remedy or treatment train approaches are discussed in subsequent sections of this CAP Preparation guidance.

Identify Targeted Treatment Areas

Targeted treatment areas represent the area where the contaminant concern exists. Targeted treatment areas must be identified and depicted in map and cross-sectional view for every remedial objective identified. Accessible and inaccessible areas should be clearly identified and appropriately described. As the figure below depicts, there are likely multiple, distinct targeted treatment areas for the identified site contaminant concerns.



Examples of targeted treatment areas

Evaluate, Screen Out, and Select the Remedial Technology or Treatment Train

This section describes a process for systematically evaluating, screening and selecting the most technically efficient and economically feasible remedial technologies to address identified contaminant concerns. This process establishes a clear basis of technology selection and should be followed when developing a

CAP. Not all concerns will be addressed in a single CAP, as discussed below in the Treatment Train section of this guidance. An overview of selected remedial technologies is provided in the CAP Technologies section. The screening tools presented within the stepped process reflect OPS' collective experience in remediating petroleum release sites. Responsible Parties may recommend technologies that do not strictly adhere to the process or technologies that were not included in the OPS reviewed technologies; however, the basis of technology selection in those situations must be clearly supported.

Step 1 - Screen Technologies Based on the Contaminant Concern and Remedial Objective

Technologies are first screened based on their demonstrated ability to achieve a particular remedial objective. This initial step will eliminate many technologies from future consideration. The table below should be utilized when completing this step. Technologies that are not eliminated from consideration should be retained for additional screening.

CORRECTIVE ACTION CONTAMINANT CONCERNS, REMEDIAL OBJECTIVES, AND REMEDIAL TECHNOLOGIES TO CONSIDER			
Contaminant Phase	Contaminant Concern	Remedial Objective	Technologies to Consider
Sorbed	Surficial soils impacted above Tier I RBSLs and surface is not covered by an impervious material	Remove or reduce surficial soil impacts to below Tier I RBSLs	●Excavation
	Vadose zone soil impacted above Tier I RBSLs and/or Tier II SSTLs and groundwater	Remove or reduce vadose zone soil impacts to below Tier I RBSLs and/or Tier II	●Excavation ●AS[1]/SVE ●SVE ●MPE (system

[1]Air Sparge

CORRECTIVE ACTION CONTAMINANT CONCERNS, REMEDIAL OBJECTIVES, AND REMEDIAL TECHNOLOGIES TO CONSIDER			
	is impacted or potentially impacted	SSTLs	or mobile, single or dual pump) ●Thermal Desorption ●Bioventing ●NSZD
	Vadose zone soil impacted below Tier I RBSLs but groundwater impacted above Tier I RBSLs	Remove or reduce vadose zone mass to address contribution to groundwater	●Excavation ●AS/SVE ●SVE ●MPE (system or mobile, single or dual pump) ●Thermal Desorption ●Bioventing ●NSZD
	Smear zone or saturated soil impacted and contributing to groundwater contaminant migration	Reduce mass in smear zone and/or saturated soil to address contribution to groundwater	●Excavation ●AS/SVE ●AS or O_2 or O_3 or Biosparge ●MPE (system or mobile, single or dual pump) ●Thermal Desorption ●SESR ●Activated Car-

CORRECTIVE ACTION CONTAMINANT CONCERNS, REMEDIAL OBJECTIVES, AND REMEDIAL TECHNOLOGIES TO CONSIDER			
			bon ●NSZD
LNAPL	LNAPL is migrating	Terminate LNAPL mass migration by mass recovery or mass control	●Excavation ●MPE (system or mobile, single or dual pump)
	LNAPL saturation is above residual sat-uration (mobile) and transmissivity is above the recoverable range	Recover LNAPL to MEP (transmissivity range)	●Excavation ●MPE (system or mobile, single or dual pump) ●Thermal Desorption ●SESR ●EFR
	LNAPL saturation is within the residual sat-uration range and a per-sistent source of dissolved phase or vapor phase concerns	Identify appropriate phase change tech-nology or excavate	●Excavation ●AS/SVE ●Thermal Desorption ●ISCO ●SESR ●NSZD
Dissolved	Impacted groundwater above Tier I RBSLs offsite and/or SSTLs onsite	Reduce groundwater concentrations to below Tier I RBSLs off-site and at POCs and	●AS/SVE ●AS, O2, O3 ●MPE (system or mobile, single

CORRECTIVE ACTION CONTAMINANT CONCERNS, REMEDIAL OBJECTIVES, AND REMEDIAL TECHNOLOGIES TO CONSIDER			
		to below Tier II SSTLs onsite	or dual pump) ●ISCO ●Activated Carbon ●Biosparge ●MNA
		Remove or address sorbed, LNAPL, or smear zone source material contributing to groundwater impact	●AS/SVE ●AS or O2 or O3 or Biosparge ●MPE (system or mobile, single or dual pump) ●Thermal Desorption ●ISCO ●Activated Carbon
	Domestic, irrigation, or water supply well impacted or potentially impacted above Tier I RBSLs	Identify alternate water supply source	
		Modify the well intake	
		Reduce incoming groundwater concentrations to below Tier I RBSLs	●AS/SVE ●AS or O2 or O3 or Biosparge ●MPE (system or mobile, single or dual pump) ●ISCO

CORRECTIVE ACTION CONTAMINANT CONCERNS, REMEDIAL OBJECTIVES, AND REMEDIAL TECHNOLOGIES TO CONSIDER			
			●Activated Carbon
		Engineered control to eliminate exposure to the receptor	
	Surficial water, springs, or sensitive environment POEs impacted	Reduce incoming groundwater concentrations to below Tier I RBSLs	●AS/SVE ●AS or O2 or O3 or Biosparge ●MPE (system or mobile, single or dual pump) ●ISCO ●Activated Carbon
		Implement measures to protect POEs from further impact	
	Impacted groundwater has intercepted a utility corridor	Evaluate and mitigate migration potential and exposure to receptors	
		Evaluate and mitigate utility worker safety concerns	
Vapor	Petroleum vapor intrusion is impacting a utility corridor and/or struc-	Remediate source (LNAPL, sorbed, dissolved) to eliminate	See sorbed, LNAPL, and dissolved phase sec-

CORRECTIVE ACTION CONTAMINANT CONCERNS, REMEDIAL OBJECTIVES, AND REMEDIAL TECHNOLOGIES TO CONSIDER			
	ture	impacts	tions above
		Engineered controls to prevent PVI	Foundation vapor barrier, sub-slab depressurization system

AS - Air Sparge	MNA - Monitored Natural Attenuation	PVI - Petroleum Vapor Intrusion
EFR - Enhanced Fluid Recovery	NSZD - Natural Source Zone Depletion	RBSLs - Risk Based Screening Levels
ISCO – In Situ Chemical Oxidation	O2 - Oxygen	SESR - Surfactant-Enhanced Subsurface Remediation
LNAPL - Light Non-Aqueous Phase Liquid	O3 - Ozone	SSTLs - Site-Specific Target Levels
MEP - Maximum Extent Practicable	POE - Point of Exposure	SVE- Soil Vapor Extraction
MPE - Multi-Phase Extraction		

Step 2 - Screen Technologies Based on the Site Geologic Factors

Technologies should then be screened based on the geologic factors associated with the particular contaminant concern. This screening step eliminates technologies that rely on certain geologic conditions that are not present within the targeted treatment area. It is important to consider the contaminant mass storage and transport zones when completing this step. Lithologic applicability is included in the Technologies Overview table in the CAP Technologies section below.

Step 3 - Prioritize Additional Evaluation Factors and Perform a Comparative Analysis

A few viable remedial technologies may remain after performing the first two screening steps. The next step is to perform a comparative analysis of relevant additional evaluation factors that are present for a particular release. Evaluation factors to consider include:

- Cost – Estimates of upfront capital and life-cycle costs should be compared for each technology.
- Site restrictions - Physical (e.g., buildings and utilities), logistical (e.g., limited area to house a remediation shed or stockpile materials) or legal (e.g., offsite property access) site restrictions.
- Remediation time frame - A release may have specific time restrictions so the estimated time frame to achieve the remedial objective should be considered (e.g., very short for excavation to very long for monitored natural attenuation).
- Safety - Safety concerns should be evaluated (e.g., construction, operation and maintenance).
- Community concerns - Potential or real community concerns should be evaluated (e.g., traffic, noise, odors, dust).
- Carbon footprint/energy requirements - Compare energy consumption and greenhouse gas emissions.
- Waste stream management - Evaluate waste generation and management.
- Other - A project-specific evaluation factor can be incorporated into this screening step.

Cost is most typically a relevant evaluation factor to consider. A few other factors should be identified with stakeholder input, and a quantitative or semi-quantitative analysis should be performed to screen and rank the remaining remedial technologies. Advantages and limitations for each technology are discussed in the CAP Technologies section below and can be used to aid in this step. Ideally, a remedial approach will be selected at the completion of this step to proceed with a more site specific evaluation of the technology.

Step 4 - Identify Critical Data Needs

The steps completed up to this point have largely been a desktop evaluation of existing data and experience. Critical field data needs should be identified and appropriately addressed prior to technology selection for full-scale application. Identification of critical data needs aid in supporting the following:

- Remedial selection - Will the selected technology effectively perform in the targeted treatment area?
- Efficacy of design - What information should be gathered to maximize the effectiveness of the technology?
- Performance monitoring – What baseline data are needed prior to implementation?

Pilot testing is an example of a critical data need and should be considered at all sites and in the context of how it aids remedial selection, efficacy of design or performance monitoring. Critical data needs vary from technology to technology. Example Critical Data Needs are included for each technology in the CAP Technologies section.

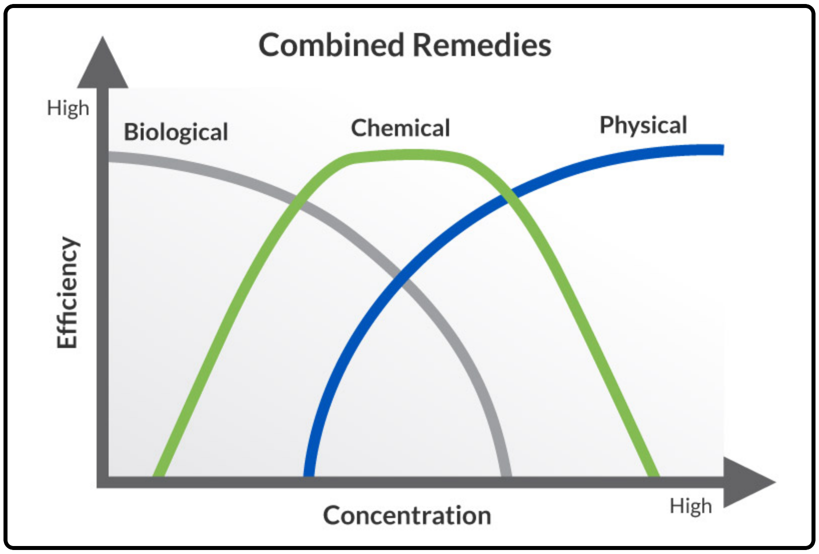
Step 5 - Select the Technology(ies) to Address the Concern(s)

Completion of the above process lays the foundation for a good basis of selection for a remedial technology. The last step of the evaluation process is to select the technology to address the contaminant concern and achieve the remedial objective. Incorporation of Green and Sustainable Remediation practices is recommended once a remedial approach has been selected. This does not necessarily represent the end of the technology selection process as there are likely multiple contaminant concerns for a given release. As such, this process should be repeated as necessary to identify appropriate technologies to address contaminant concerns and achieve remediation goals. This process can be utilized to address multiple concerns within the same targeted area. Certain technologies may be able to address multiple remedial objectives and may offer the greatest utility for a release event. As described in the Define Remedial Goals and Objectives section above, a SMART objective should be developed for each remediation goal. This includes the identification of technology specific performance metrics and remedial endpoints. Technology specific remedial endpoints may not necessarily result in the elimination of the contaminant concern. For that reason, identification of a potential treatment train strategy may be appropriate to achieve site closure.

Treatment Train or Combined Remedy Consideration

Formerly, a single remedial technology was typically selected with the expectation that the technology would achieve closure conditions for a release event. Experience has shown that this approach often did not achieve closure conditions and that another technology needed to be implemented after years of ineffective and costly assessment of the situation. The use of multiple technologies should be thoughtful and deliberate, rather than a reaction to a failed technology. A more practical and cost effective approach may be to sequence or combine technologies based on the specific contaminant concerns and associated remedial goals.

A treatment train is a sequence of multiple remedial technologies, beginning with a primary remedy that will effectively treat the highest mass or concentrations of contamination that is followed by a secondary treatment technology to address remaining mass and, if necessary, a tertiary polishing step to achieve site closure. A combined remedy approach is similar to a treatment train, except that the methods are employed concurrently.



Combined remedies chart from [Regenesis]

Performance Metric, Remedial Milestone and Endpoint Identification

Performance metrics are measurable characteristics that relate to the remedial progress of a technology in achieving the remedial objective and abating the contaminant concern. Technologies function differently (e.g., excavation versus MNA) and therefore the performance metrics used to demonstrate remedial progress depend on the technology used.

Some examples of performance metrics include the collection of the following:

- Air emission samples to evaluate contaminant mass reductions (common for mechanical systems).
- Specific indicators to evaluate the distribution and efficacy of an in-situ application.
- Geochemical parameters to aid in the understanding of the CSM, natural processes, and chemical specific decay rates (common for MNA).

- Groundwater samples to evaluate progress toward the remedial objective (common for dissolved phase contaminant concerns).
- Interim or final soil confirmation samples to evaluate the reduction of contaminant mass (common for sorbed phase contaminant concerns).

Performance metric collection frequency or occurrence should be related to remedial milestones. Examples of remedial milestones may include:

- Periodic collection of air emission samples to evaluate progress toward the remedial goal or system limitations (e.g., asymptotic levels as an endpoint).
- 50% mass reduction achieved based on an initial contaminant mass estimate.
- Groundwater BTEX concentrations remediated to 25%, 50% or 75% of either the SSTL or RBSL.

Ideally, each performance metric has a predetermined value that describes when the technology has reached the limits of beneficial application. That is the end point metric for the technology chosen and the associated remedial objective. As previously stated, technology specific end points do not necessarily eliminate the environmental concerns derived from the CSM. Technology specific endpoints should however appropriately account for the expectations of the technology.

Identification of relevant performance metrics, their sample collection frequency or occurrence, and the technology specific remedial endpoints should be clearly presented in the CAP for each and all remedial objectives.

Identify Groundwater Monitoring Network and Sampling Frequency

As it relates to identified contaminant concerns, a groundwater monitoring network should largely coincide with the targeted treatment areas where the dissolved phase concern exists. Further, a groundwater monitoring network should adequately represent the understanding of the contaminant plume area, stability and migration potential. It is important to consider that a monitoring well network is designed to be representative of an area. It may be entirely appropriate to collect spatially relevant groundwater samples at locations other than the established monitoring well network to evaluate abatement of the contaminant concern within the targeted area. Tools are available to help establish a statistically significance monitoring schedule.

Sampling frequency should coincide with the milestones identified to evaluate progress toward the established remedial endpoint (i.e., RBSLs or SSTLs). At most sites, sampling frequency may vary from well to well based on the following:

- Intended purpose of the well (point of compliance versus source area)
- Historic understanding of the well
- Anticipated remedial change within the well

In general, monitoring wells should be sampled when it is expected that the data will be evaluated in a meaningful way (e.g., progress toward closure or confirmation of the CSM).

Identify Monitoring and Remediation Reporting Frequency

Monitoring and Remediation Reports (MRRs) should be submitted on a frequency that generally coincides with evaluation of the identified performance milestones and within the time frame identified to evaluate the remedial objective. Expectations associated with report evaluations are presented in the CAP Implementation section.

CAP Submittal

An acceptable CAP submittal will include all of the above components for every contaminant concern identified to be addressed within the CAP. As discussed, treatment train approaches may benefit the time and money spent on the release in the long run and should be considered. It may be appropriate to identify that a contaminant concern will not be specifically addressed within the initial corrective action phases so long as it is presented that the the concern will be aided by the proposed plan and/or that the concern will be addressed in a subsequent phased approach.

CAP Technologies

The purpose of this section is to provide an overview of remedial technologies that are applicable to petroleum release sites. The selected remedial technology, or technology treatment train for a CAP, should align with the remedial objectives for addressing site-specific contaminant concerns identified within the conceptual site model (CSM). The table below summarizes remedial technologies to consider during the CAP technology selection process. These are the technologies that OPS has the most experience with and represent the majority of approved applications within the state's program to date.

Overview of Remedial Technologies		
Technology	**Technology Description**	**Applicable Lithology ([a, b])**
Excavation	Contaminant mass is physically removed and properly treated or disposed.	F + C
Air Sparge/Soil Vapor Extraction (AS/SVE)	AS injects air into the saturated zone to volatilize contaminants and SVE induces a vacuum to remove vapors from the vadose zone. AS or SVE can be used individually if site conditions are appropriate.	C
Biosparging and Bioventing	Air or oxygen is injected at low flow rates into the unsaturated zone (bioventing) or saturated zone (biosparging) to stimulate contaminant biodegradation.	F + C

Multi-Phase Extraction	An induced vacuum removes LNAPL, groundwater and vapor from the subsurface. A single pump or dual pump system may be employed and a fixed or mobile system may be designed depending on the complexity and magnitude of the environmental impact.	F + C
In-Situ Chemical Oxidation (ISCO)	A chemical oxidant (e.g., H_2O_2, $NaSO_4$, O_3), typically with amendments, is introduced into the subsurface to convert contaminants into innocuous byproducts.	C
Activated Carbon	Activated carbon, typically with bio-nutrients and/or oxidants, is introduced in the subsurface to adsorb contaminant mass (trap) and enable biological degradation processes to occur (treat).	C
Surfactant-enhanced subsurface remediation (SESR)	A surfactant is injected to increase LNAPL solubilization and mobility to enable recovery of dissolved phase and LNAPL via extraction wells.	C
Enhanced Biodegradation	Electron acceptors (i.e., oxygen, nitrate, sulfate) or nutrients (i.e., trace elements) are added to improve biodegradation rates within the saturated zone.	F + C
Thermal Desorption	Energy is used to heat soil, pore space, and groundwater to volatilize contaminant mass and reduce the viscosity and interfacial tension of LNAPL to enable recovery of liquid and vapor contaminants via extraction wells.	F + C
Enhanced Fluid Recovery (EFR)	LNAPL is hydraulically recovered by a vacuum-enhanced process.	C
Monitored Natural Attenuation (MNA) and Natural Source Zone Depletion (NSZD)	Contaminant mass is naturally degraded or depleted over time by physical, chemical, or biological processes.	F + C

(a) C = coarse-grained lithology (sands and gravels) and F = fine-

grained lithology (silts and clays).
(b) The recommended applicable lithology is based on OPS' collective remedial application experience. Site-specific lithologies should be critically understood when considering a technology's ability to achieve the remedial objectives within the targeted treatment area(s).

Specific remedial technology descriptions are provided below with their associated critical data needs, advantages, limitations, and remedial performance metrics.

The ITRC has identified corrective action technologies specifically for LNAPL, and mitigation technologies specifically for PVI. Please refer to those documents for additional information on LNAPL remediation and PVI mitigation.

Excavation

Excavation is the fastest and most effective remedial technology for surficial, vadose zone, and smear zone soil impacts. Removed contaminated material can either be disposed offsite, land farmed, or treated onsite (e.g., soil shredding, ex-situ thermal desorption) or offsite. In addition to removing soil impacts, excavation can also be used to expose the water table to enable direct treatment of contaminated groundwater (e.g., ISCO, activated carbon). Excavation can be the sole remedial technology and is commonly utilized as the primary remedy in a treatment train. However, excavation is not always possible due to access restrictions and there are a number of factors to consider when evaluating this option as described below.

Critical Data Needs

Although pilot testing is typically not required for excavation, additional data may be necessary to better define the area(s) to be excavated. A grid pattern of direct push borings is an effective manner of delineating the targeted excavation area and depth. During excavation, field screening should be conducted to provide real time data to aid in decision making such as horizontal and vertical excavation limits and confirmation soil sample locations.

A Materials Management Plan should be prepared to address the following questions:

- How much soil will need to be disposed or treated, and can the impacted soil be treated onsite and reused, or transported to a landfill or landfarm?
- What are landfill or landfarm requirements?
- Is clean overburden in the excavation zone, and can it be segregated and reused?
- Are Green and Sustainable Remediation principles being used?
- Have soil expansion factors (tons versus yards) been considered for transportation?
- Can surface cover be recycled?
- Will groundwater be encountered?
- What is the infiltration rate and will dewatering be necessary?
- Should a vapor barrier be added during backfill?
- Should infiltration piping be installed in the excavation prior to backfilling to facilitate future applications of ISCO, activated carbon, or nutrients?

Advantages

- Expedient removal of source area contaminant mass.
- Assurance that complete removal of accessible, targeted treatment area occurs.
- Ability to apply ISCO, activated carbon, or nutrients, directly to the exposed water table for groundwater remediation.

- Ability to install infiltration piping system in the excavation prior to backfilling to facilitate the application of future ISCO, activated carbon, or nutrient applications to the dissolved phase plume, if necessary.

Limitations

- Access restrictions posed by subsurface utilities, tank system components, onsite structures, and overhead restrictions such as dispenser canopies.
- Safety issues such as petroleum vapors, vapor monitoring and control, exclusion zone fencing, pedestrian concerns, and traffic control measures.
- Soil type(s) and hydrologic conditions may be a limiting factor for sloping or shoring, which may present OSHA restrictions.
- Carbon footprint should be considered.
- State and/or local regulations may require specific permits for groundwater dewatering, treatment or disposal, and stormwater management.
- Potential high-cost option based on quantity and available disposal/treatment options.

Performance Metrics

Excavation performance metrics must include adequate sidewall and floor soil confirmation samples. Documentation of the completed excavation must be entered into monitoring report tables and figures, and soil disposal manifests and/or data of treated mass must be provided. A photographic record of the excavation process is strongly recommended. Models such as "REMFUEL" can be used to evaluate the effectiveness of excavation on reducing the project lifetime and determine if and when the next step in the treatment train should be implemented.

Air Sparge/Soil Vapor Extraction (AS/SVE)

Air sparge (AS) and soil vapor extraction (SVE) are common in-situ remedial methods for volatile fuel contamination. AS injects ambient air below the saturated zone to aerate the fuel contamination. SVE then induces a vacuum that volatilizes and removes fuel contamination in the vadose zone. Under applicable conditions, AS/SVE is capable of addressing moderate to high contaminant concentrations in the vadose, smear, and saturated zones. AS/SVE is often combined with excavation as part of a treatment train. AS/SVE designs should address targeted treatment areas identified during site characterization and subsequent data collection and CSM refinement. AS/SVE systems can be designed to also operate as biosparging/bioventing remediation systems, which are described below.

Critical Data Needs

Pilot testing should be conducted to evaluate AS/SVE technical feasibility and proper system design. The goal of the pilot test(s) is to measure and predict the effects of full-scale AS/SVE system operation, either separately or combined. Therefore, pilot test wells should be designed and constructed similar to the proposed full-scale design. Pilot testing must provide data on sustainable air flow rates, contaminant vapor removal rates, subsurface air flow vectors, effective radius-of-influence (ROI), and the number of AS/SVE wells needed to address the targeted treatment area(s). Pilot testing is also an opportunity to collect additional soil, groundwater, and vapor data to refine the CSM and optimize the CAP. If AS or SVE will be implemented individually as a stand-alone technology, pilot testing should be conducted as a step test using a minimum of three air flow rate steps. If AS will be used in conjunction with SVE, it is important to conduct step tests separately and in conjunction. A minimum of three monitoring points, at varying directions and distances (i.e., 10 feet, 20 feet, 30 feet, etc.) from the test point(s), is typical to observe the effect of pilot testing. Existing groundwater monitoring wells may be appropriate to act as pilot test monitoring points.

Advantages

●Proven technology with numerous case studies to document feasibility.
●Ability to treat moderate to high contaminant concentrations over a large treatment area.
●Relatively shorter timeframe to achieve remedial objectives.
●May also be implemented actively or passively, or mobile systems may be utilized if remedial timeframes or treatment areas are small.
●SVE can provide significant fugitive vapor control for prevention of PVI issues.

Limitations

●Limited effectiveness in low-permeability, fine-grained soil.
●Permitting requirements vary by city and county.
●Carbon footprint should be considered.
●Vapor emissions should be considered, and APEN permit may be required from CDPHE.
●Community concerns such as noise should be considered.

Performance Metrics

Performance metrics for AS/SVE remediation will generally include measuring the rate of extraction in the SVE effluent, and evaluation of the reduction in contaminant plume size and concentrations relative to calculated SSTLs. Mass removal calculations should be performed and tracked relative to initial contaminant mass estimates. Remediation progress of vadose and/or smear zone contamination will can be demonstrated through confirmation soil sampling, and by groundwater monitoring for the dissolved phase plume. ROI measurements should be performed to verify system performance, in addition to system optimization which can provide greater remedial effort to areas with remaining impacts. Sustained asymptotic levels after system optimization may be indicative of an effective endpoint for the AS/SVE system.

References

Design Criteria and Reporting Requirements (Vapor Extraction, Air Sparging) Guidance Document #17, Minnesota Pollution Control Agency Voluntary Investigation and Cleanup

Clu-In Air Sparging Guidance Document, Battelle, 2001

Guidance on Soil Vapor Extraction Optimization, Prepared For Air Force Center for Environmental Excellence, Brooks AFB, Texas

Biosparge/Biovent

A biosparging system is similar to an AS system, except lower flow rates of air, or oxygen, are used to enhance bioremediation (the primary mechanism of biosparging) in the saturated zone, while minimizing volatilization (the primary mechanism of AS). Therefore, biosparging is a mechanical system near the biological end of the treatment train and is generally employed to address moderate to low contaminant concentrations. Bioventing is similar to SVE however air is injected, rather than extracted, at lower flows and volumes into the vadose zone to promote biodegradation. Biosparging and bioventing may be used alone or in conjunction with other technologies.

Critical Data Needs

Field pilot testing provides data on sustainable air flow rates, air pressures, subsurface air flow vectors, effective ROI, and the number of sparge or injection points needed. Pilot testing is also an opportunity to collect additional soil, groundwater, or vapor samples to refine the CSM and optimize the remediation plan. Similar to AS/SVE pilot testing, a minimum of three monitoring points, at varying directions and distances from the test point(s), is typical to observe the effect of pilot testing. Step tests will provide better data for optimal design. Existing groundwater monitoring wells may be useful as pilot test monitoring points.

Advantages

- Because air is injected at low flow rates, biosparging/bioventing can be effective in fine-grained lithology where AS/SVE is generally not technically feasible.
- PVI can be avoided by biosparging and bioventing at low flow rates, which eliminates the necessity for vapor capture or control by an SVE system.
- Liquid nutrients (see biodegradation) may also be added to the air stream to increase nutrient content and soil moisture if they are known to be limiting factors to bioremediation.
- Ability to convert an AS/SVE system to a biosparging or bioventing system when asymptotic limits of the AS/SVE system have been reached. This enables another step in a treatment train, which is a technically-efficient and cost-effective benefit.

Limitations

- Generally medium to longer timeframes to achieve remedial objectives.
- Ineffective for large mass, high contaminant concentrations.

Performance Metrics

Performance metrics include measuring airflow and pressure at each point, changes in groundwater DO and ORP, and monitoring oxygen and CO2 in soil vapor samples. Remedial progress for vadose and/or smear zone contamination will generally be demonstrated by confirmation soil sampling, and by groundwater monitoring of the dissolved phase plume.

References

How to Evaluate Alternative Cleanup Technologies for Underground Storage Tank Sites, A Guide for Corrective Action Plan Reviewers (Chapters 3 and 8) EPA 510-R-04-002 May 2004

Biosparging Pilot Test Guidance, (Florida DEQ)

Bioventing

Procedures for Conducting Bioventing Pilot Tests and Long-Term Monitoring of Bioventing Systems, AFCEE 2004

Bioventing Degradation Rates of Petroleum Hydrocarbons and Determination of Scale-up Factors, A.A. Khan PhD Thesis, 2013

Multi-Phase Extraction (MPE)

MPE involves the removal of LNAPL, groundwater, and vapor from the sub-surface. There are multiple configurations of wells and equipment for MPE including:

- Using a submersible (electric) pump.
- Using a total fluids (pneumatic) pump.
- Adding well-bore vacuum extraction to either of these techniques which improves liquid recovery and also ventilates the vadose zone.
- Using a “drop tube” to entrain liquid in an (extracted) air stream, commonly known as Dual-Phase Extraction (DPE) or MPE.

Typically, sites with groundwater recovery rates greater than two (2) gallons per minute employ submersible pumps, and as hydraulic conductivity decreases, system designs move downward through the list to MPE. If minor LNAPL is present, total fluids pumps minimize emulsion with water, making LNAPL separation during treatment feasible.

MPE is applicable when contaminant concentrations are moderate to high, and depending on how the system is designed, it can be successful in a wide variety of situations. Most often MPE is used for LNAPL control/recovery, plume and vapor control (prevention of impact to a receptor), or, as one of the primary remedial technologies in a treatment train.

Critical Data Needs

Field pilot testing provides data on sustainable liquid recovery rates, air flows, drawdown, and the number of extraction points needed. Pilot testing is also an opportunity to collect additional soil/groundwater/vapor samples to refine the CSM and optimize the remediation plan. Pilot testing may take several days to allow static conditions to develop in the aquifer. Similar to AS/SVE and biosparging, a minimum of three monitoring points, at varying directions and distances from the test point(s), is typical to observe the effect of pilot testing. Existing groundwater monitoring wells may be used during testing. Pilot test wells should have similar construction to the intended final design so that testing data is directly applicable.

Advantages

●Multiple contaminant phases recovered simultaneously with a single technology.
●Provides hydraulic control.
●Provides vapor control.
●Effective for large and small treatment areas.

Limitations

●Moderate timeframe to achieve remedial objectives.
●MPE is relatively complicated and involves site construction, business interference, and permitting requirements.
●Significant troubleshooting issues associated with operation and maintenance.
●Moderate capital and operation and maintenance costs.
●If reinjection is considered, water conditioning and filtration will be necessary to avoid plugging the reinjection gallery prematurely, and a UIC permit will be required.
●Weather-proofing for winter operation is critical.

● Frequent maintenance to remove mineralization or biogrowth from treatment equipment.

Performance Metrics

System performance metrics will generally include measuring fluid flows, drawdown, vacuum ROI, and vapor emissions. Mass removal and LNAPL removal calculations should be performed and tracked relative to initial contaminant mass estimates. Performance metrics in vadose and/or smear zone contamination will generally be demonstrated through confirmatory soil sampling, and by groundwater monitoring for the dissolved phase plume.

References

Basics of Pump-and-Treat Ground-Water Remediation Technology, USEPA, 1990. EPA-600/8-90/003

Options for Discharging Treated Water from Pump and Treat Systems, USEPA, 2007. EPA 542-R-07-006

How to Evaluate Alternative Cleanup Technologies for Underground Storage Tank Sites, A Guide for Corrective Action Plan Reviewers (Chapter 11) EPA EPA 510-B-16-005 November 2016

Multi-Phase Extraction Engineering and Design, US Army Corps. Engrs. 1999. EM 1110-1-4010

Multi-Phase Extraction: State-of-the-Practice USEPA, 1999. EPA 542-R-99-004

In Situ Chemical Oxidation (ISCO)

ISCO reagents serve as oxidants that react with dissolved petroleum hydrocarbons (and other organic materials) causing rapid conversion of hydrocarbons to innocuous products such as carbon dioxide and water. ISCO reagents can also reduce sorbed phase saturated mass either through direct contact or phase partitioning from the sorbed phase to the dissolved phase. ISCO applications are appropriate for high to moderate dissolved phase concentrations and can be effective as a primary, secondary, or tertiary polishing step in a treatment train, depending on the identified contaminant concerns.

ISCO reagents are most typically introduced into the subsurface via pressurized injections using dedicated injection equipment. Other applications include French drain (or gravity feed) systems, and direct application to an open excavation. Common ISCO reagents include hydrogen peroxide, Fenton's Reagent (hydrogen peroxide catalyzed with iron), sodium persulfate, oxygen, and ozone (gas).

Ozone is unique to the other ISCO-based reagents in that the process usually involves injection of a gas rather than a liquid. Design and operational issues are different for ozone gas injections than with liquid oxidant injections.

Critical Data Needs

Successful remediation using ISCO is dependent on a thorough understanding of subsurface conditions including, but not limited to, hydrogeology, contaminant distribution, mass storage and mass flux areas, and geochemical setting. Accurate contaminant mass estimates along with native soil oxidant demand estimates are needed within the identified targeted treatment area to establish a stoichiometric basis of optimal reagent dose. Critical data necessary for successful ozone gas injections include a determination of bacterial biomass, total organic carbon (TOC), iron (Fe), manganese (Mn), hydrogen sulfide (H2SO4), and carbonate levels.

Pilot testing should be considered to confirm the formations ability to accept the ISCO reagent. Additionally, pilot testing activities should aid in providing a basis for full-scale implementation. Baseline performance monitoring data should also be considered.

Advantages

●Rapid contaminant conversion (short timeframe).
●Relatively easy to work around physical and business restrictions within a targeted treatment area for pressurized injection application.
●Pressurized injection applications do not have capital or high infrastructure costs.
●High solubility of ozone.

Limitations

●Difficult to ensure contact between the ISCO reagent and targeted contaminant mass.
●Short reagent longevity. Dispersion cannot be relied on to facilitate contact.
●Can be cost prohibitive based on mass and soil oxidant demand estimates.
●Potential corrosive damage to tank systems and utilities, and surfacing of ISCO injectate in nearby basements, water wells, or surface water features.
●If present, common soil matrix (i.e., TOC, Fe, carbonates, etc.) can consume ozone prior to reaction with contaminants and limit effectiveness.

Performance Metrics

The primary performance metrics for ISCO applications are reductions in dissolved phase and sorbed phase concentrations within the targeted treatment area(s). Groundwater monitoring well data may be used to assess dissolved phase concentrations but other assessment locations within the targeted treatment area should also be considered. Secondary geochemical parameters specific to the oxidant and reaction may also be used to evaluate performance, distribution, and effect.

Activated Carbon

Carbon-based reagents are applied to targeted treatment areas where the activated carbon serves as a adsorption substrate for biodegradation of petroleum hydrocarbons under aerobic and anaerobic conditions. Activated carbon reagents are comprised of activated carbon that may be mixed with oxidants, bacteria, and nutrients. Activated carbon is most typically introduced into the subsurface via pressurized injections using dedicated injection equipment. Direct placement into an open excavation is another application method. Activated carbon applications are appropriate for moderate to low contaminant concentrations and as a secondary or tertiary polishing step in a treatment train.

Critical Data Needs

Successful remediation using carbon-based reagents is dependent on a thorough understanding of subsurface conditions including, but not limited to, hydrogeology, contaminant distribution, mass storage, mass flux areas, and geochemical setting. Contaminant mass estimates are needed within targeted treatment areas to establish a basis of optimal reagent amount.

Pilot testing should be considered to confirm the formations ability to accept material. Additionally, pilot testing activities should aid in providing a basis for full-scale implementation. Baseline performance monitoring data should also be considered.

Advantages

●Contaminant adsorption allows for sustained longevity of the bioremediation process.
●Carbon sequesters dissolved phase contaminants and reduces transport and flux.
●Relatively easy to work around physical and business restrictions within a targeted. treatment area for pressurized injection applications.

Limitations

●Difficult to ensure contact between with the targeted contaminant mass.
●Can be costly based on mass.
●Carbon can impact monitoring wells and compromise the ability of the well to be representative of the subsurface conditions.

Performance Metrics

The primary performance metrics for carbon-based reagent applications are reductions in dissolved phase and sorbed phase concentrations within the targeted treatment area(s). Groundwater monitoring well data may be used to assess dissolved phase concentrations, unless there is evidence that a monitoring well has been impacted by carbon, but other assessment locations within the targeted treatment area should also be considered. Secondary geochemical parameters specific to the added amendments may also be used to evaluate performance, distribution, and effect.

Surfactant-Enhanced Subsurface Remediation (SESR)

SESR involves the injection of surfactants into the subsurface to desorb and mobilize LNAPL for subsequent mass recovery via extraction wells. Also referred to as surfactant flushing or soil washing, surfactant injections can be effective at treating the source of a dissolved phase plume to expedite site closure. SESR should be considered when persistent dissolved phase concentrations are observed because of residual quantities of LNAPL within the targeted pore spaces or to accelerate recovery of mobile LNAPL.

Critical Data Needs

Critical data needs for SESR includes the delineation of LNAPL targeted treatment zones to effectively design surfactant injections, LNAPL transmissivity values and gauged LNAPL in-well thicknesses are important data needs prior to implementation. LNAPL volume estimates and recovery estimates should also be considered.

Advantages

- Can effectively achieve LNAPL recovery.
- Short to very short time frame.

Limitations

●Potential access restrictions due to the presence of utilities and tank system components.
●Lithologic heterogeneity of targeted treatment areas.
●Costs and logistics associated with fluid treatment and disposal.

Performance Metrics

Performance metrics include reductions in LNAPL transmissivity, LNAPL recovery volumes, gauged in-well thicknesses, and dissolved phase contaminant concentrations over time.

Enhanced Biodegradation

Enhanced biodegradation is appropriate for relatively low contaminant concentrations or as a secondary or tertiary polishing step in a treatment train. Nutrients, such as nitrate and sulfate, are introduced into targeted treatment areas of the smear zone and saturated zone to enhance the biodegradation of petroleum hydrocarbons (biostimulation). The addition of bacteria (bioaugmentation) can also enhance the biodegradation of petroleum hydrocarbons.

Amendments are most typically introduced into the subsurface via pressurized injections using dedicated injection equipment. Other applications include French drain (or gravity feed) systems, and direct application to an open excavation.

Critical Data Needs

Successful remediation using enhanced biodegradation is dependent on a thorough understanding of subsurface conditions including, but not limited to, hydrogeology, contaminant distribution, mass storage and mass flux areas, and geochemical setting. Bench testing and or analytical data should be considered to identify the limiting factors prohibiting degradation processes to determine an optimal nutrient or bacteria addition. The collection of pre-introduction baseline data is important for petroleum contaminants of concern, nutrients, and geochemical parameters to enable comparison with post-introduction data.

Advantages

- Low cost.
- Applicable for low concentrations.
- Can be used in conjunction with biosparging to expedite remedial time frame

Limitations

- Potential access restrictions for injections (e.g., utilities and tank system components).
- Limiting factors may be difficult to determine and must be well understood prior to implementation.
- Potential long timeframe to achieve objectives.

Performance Metrics

Performance metrics for enhanced biodegradation include groundwater monitoring for primary and secondary parameters to track the effect of the nutrient addition on the targeted treatment area and overall subsurface environment. Primary parameters include petroleum contaminants of concern, and secondary parameters include nutrients (e.g., nitrogen, phosphorus, sulfate) and key geochemical parameters such as DO, pH, and ORP.

Thermal Desorption (TD)

TD is a physical separation process that uses heat exchange to volatilize organic contaminants from a solid matrix. Air, combustion gas, or an inert gas is then used as a transfer medium to collect and treat the vaporized contaminants. All TD technologies consist of two steps: (1) heating the contaminated solids to volatilize the organic contaminants, and (2) treating the exhaust vapor stream to prevent emissions of the volatilized contaminants to the atmosphere. To be effective, TD systems must have adequate residence time, temperature, and mixing during the TD process. TD can be achieved by either in-situ or ex-situ treatment systems.

Critical Data Needs

Critical data needs for TD include characterizing the contaminants of concern, soil lithology, soil moisture content, and hydraulic conductivity. Depending on the contaminants of concern, soil is typically heated to temperatures ranging from 300 to 1,000 °F. For ex-situ TD, coarse-grained unconsolidated lithology such as sands and fine gravels are more readily treated because more surface area is exposed to the heating medium; clays may cause poor ex-situ TD performance by caking and inhibited heat transfer. Soil moisture content between 10% and 20% is optimal to mitigate dust problems during material-handling operations. Bench or pilot-scale treatability studies can be performed to assess the suitability of TD and for predicting the costs of full-scale operations.

Advantages

- Applicable for a wide range of volatile organic compounds, semivolatile organic compounds, and higher-boiling-point chlorinated compounds.
- Complete removal of contaminants.
- Fast to very fast remedial time frames.
- In-situ TD is essentially a “closed loop” system without the negative issues of noise, dust, fumes, and soil sorting posed by ex-situ TD.
- In-situ TD processes have very long residence times, which favor removal mechanisms that may be time dependent.
- In-situ TD increases soil permeability to enable effective treatment of clays and silts.
- Ex-situ TD remediated soils can be used as backfill.

Limitations

●High capital costs.
●High energy costs for the heat source.
●Availability of adequate onsite utilities (fuel or electricity).
●Noise, dust, fumes, odors, and soil sorting for ex-situ TD.
●Sufficient space for ex-situ TD system, soil preparation, and treated soil staging area.
●Moisture content above 20% can increase operating costs for ex-situ TD.
●Carbon footprint should be considered.

Performance Metrics

TD system performance is measured by comparing analytical results of untreated soil samples with analytical results of processed soils.

References

Thermal Conduction Heating for In-Situ Thermal Desorption of Soils, George L. Stegemeier (GSL Engineering, Inc.) and Harold J. Vinegar (Shell E&P Technology Applications and Research Co.), 2001

Thermal Desorption Ex Situ Soil Remediation Technology, Remediation Technologies Screening Matrix and Reference Guide, Version 4.0, Federal Remediation Technologies Roundtable.

Application Guide for Thermal Desorption Systems, Foster Wheeler Environmental Corporation and Battelle Corporation, Naval Facilities Engineering Service Center, April 1998.

Enhanced Fluid Recovery (EFR)

EFR uses vacuum-enhanced recovery for mass removal of LNAPL from the saturated zone and perched LNAPL zones. LNAPL is primarily removed as a liquid but when used in conjunction with an induced vacuum, vapors are also extracted from the capillary fringe and vadose zone. Mass removal via EFR is most effective within a short time from when the release occurred (e.g., known catastrophic release).

Critical Data Needs

Critical data needs include delineation of LNAPL zones, and the measurement of LNAPL transmissivity from LNAPL baildown tests. LNAPL volume estimates and recovery estimates should also be developed.

Advantages

- Expedient recovery of migrating LNAPL.
- Effective in high-transmissivity coarse-grained lithology (sands and gravels).
- May be applied in heterogeneous soils where the EFR-induced vacuum can extract LNAPL from preferential pathways where LNAPL typically migrates and resides.

Limitations

- Not as effective in fine-grained low-permeability lithology such as silts and clays.
- Not effective as a dissolved-phase recovery technology.
- Waste management costs associated with fluid treatment and disposal.
- Long to very long remedial time frames for low-permeability soils.

Performance Metrics

Performance metrics for LNAPL recovery via EFR include decreasing LNAPL transmissivity (Tn) over time, and the quantity of LNAPL recovered as a percentage of the initial LNAPL volume estimate.

Monitored Natural Attenuation (MNA) and Natural Source Zone Depletion (NSZD)

Petroleum contamination resides in the subsurface in four distinct phases: free (LNAPL), sorbed, dissolved, or vapor. Under favorable conditions, the combination of natural physical, chemical or biological processes will degrade chemicals of concern and reduce the risk associated with the release. In the context of petroleum releases, MNA refers to the attenuation of petroleum constituents in the dissolved phase, while NSZD focuses on the depletion of mass within the source zone. These natural remediation methods are typically considered as a tertiary step in a treatment train and should only be considered when contaminant conditions are stable and the release sources have been removed, repaired or replaced.

Critical Data Needs

Estimating and confirming the rate at which these natural processes degrade or deplete contaminants of concern is a critical data need for these technologies. In addition, a thorough understanding is needed of subsurface conditions including, but not limited to, hydrogeology, contaminant distribution, and geochemical setting. OPS' MNA tool or fate and transport modeling may be used as a line of evidence to support MNA. The MNA tool is available in the MNA Feasibility tab in the Corrective Action Plan Report format.

Advantages

●No capital or infrastructure costs.
●Minimal physical and/or business restrictions.

Limitations

●Long to very long time frame.
●A lot of analytical data may need to be collected to support the degradation rates and/or understand the MNA and NSZD processes.

Performance Metrics

MNA performance metrics for dissolved phase contamination include groundwater monitoring to track reductions in COC concentrations and plume size.

Secondary groundwater parameters such as nitrate, sulfate, iron, temperature, and pH, should be monitored to track geochemical conditions. NSZD performance metrics include measuring the vertical distribution of soil gas constituents (O2, CO2, methane, and vapor phase petroleum hydrocarbons) over space and time, and estimating petroleum hydrocarbon mass loss rates and quantities through volatilization and biodegradation processes.

References

ASTM E1943: Standard Guide for Remediation of Groundwater by Natural Attenuation at Petroleum Release Sites

Evaluating Natural Source Zone Depletion at Sites with LNAPL ITRC, April 2009

CAP Implementation

Upon OPS approval, implement the selected remedial technology or sequenced treatment train. Components of a CAP implementation should include system installation, system start-up and optimization, system O&M (operation and maintenance) and remedial performance data and end point evaluation.

System Installation

System installation of the selected remedial technology should include obtaining all required access agreements, permitting requirements, equipment procurement, contractor bids (if necessary) and an anticipated installation schedule and time frame (which should include post-remediation monitoring).

Start-up and Optimization

Perform start-up activities and utilize optimization activities to identify any system limitations that may not have been evident or observed during pilot testing activities (i.e., critical data collection). Examples include blower/compressor size limitations, vacuum influence and flow rate irregularities.

O&M

Detail O&M activities related to remediation system in the number (or frequency) of O&M visits, tasks to be completed, data to be collected during O&M visits and, if warranted, additional optimization efforts to maximize remediation efficiency. Perform careful monitoring of the performance metrics defined in the CAP Submittal section during the O&M phase. This monitoring will allow OPS to evaluate the remediation progress and determine when a remedial technology has been applied to the maximum extent practicable.

Remedial milestones, as defined above, are logical points to evaluate remedial performance data during the O&M phase and can also be used to demonstrate that the specific remedial technology has been applied to the maximum extent practicable. For example, submitting a monitoring and remediation report could be an appropriate juncture to provide the status and efficacy of the remedial technology being implemented.

Performance Metric Evaluation

Evaluate the performance metric data identified in the development phase to assess the progress of the remedial approach and to measure progress toward the remediation milestones, end points, and objectives.

Remedial Milestone Evaluation

Remediation milestones are junctures when decisions need to be made, such as moving to the next step/phase in a treatment train strategy, verifying that performance metrics have been met or requesting NFA and site closure. Evaluate the remediation milestones throughout CAP implementation.

Remedial Performance Data Evaluation

After a full-scale remedial technology has reached a remedial milestone, evaluate the long-term effectiveness of the technology for meeting remedial objectives.

Below are some data evaluation examples.

- Collecting interim soil confirmation samples to determine whether the system has also reduced subsurface soil concentrations to SSTLs or RBSLs when off-gas readings associated with an SVE system have reached asymptotic levels
- Collecting groundwater plume data after introducing in-situ amendments that may indicate whether SSTLs or RBSLs have been achieved
- Drilling intra-plume confirmation soil borings/monitoring wells to ensure that smear zone soils and the dissolved phase groundwater plume have been reduced to SSTLs or RBSLs

Continue to evaluate performance metrics after achieving a remedial milestone to monitor the progress and efficacy of remediation. Examples include:

- Estimating the mass reduction achieved by the remedial technology and the mass remaining in a completed exposure pathway (i.e., subsurface vadose soil leaching to groundwater) based on the original SCR mass estimates
- Estimating the decrease in LNAPL mass recoverability, mobility and migration
- Estimating the reduction in the mass flux migrating downgradient within the dissolved phase groundwater plume as a direct result of mass reduction that occurred within the source area

Based on the results of the remedial performance evaluation, the remedial system may require optimization adjustments, or you may implement the next remedial sequence in the treatment train.

Evaluate Remedial Objectives

After the remedial performance data evaluation has been completed, answer the following questions to determine if the remedial objectives have been met.

- Are POEs protected?
- Has mass reduction been achieved?
- Was LNAPL recovery achieved?
- Have subsurface vadose soils been remediated to SSTLs or RBSLs?
- Has the smear zone been adequately treated to prevent further leaching to the dissolved phase groundwater plume?
- Has the dissolved phase plume been remediated to SSTLs or RBSLs?
- Has the downgradient or off-site mass flux been reduced?

If the answers to any of these questions indicate that the remedial objectives have not been met, identify, address and incorporate data gaps into the CSM to move the CAP implementation forward. This may require moving to the next sequence, or phase, in the treatment train strategy to progress the event to closure.

When all exposure pathways have been eliminated, request an NFA for the release event.

Additional Resources:

[Leaking Underground Storage Tanks Corrective Action Resources]

[ITRC In Situ Chemical Oxidation]

[ITRC Mass Flux and Mass Discharge]

[ITRC MTBE and Other Oxigenates]

[ITRC Passive Samplers]

[ITRC Remediation Process Optimization]

[ITRC Remediation Risk Management]

Release Closure Criteria

Closure of a release event and issuance of an NFA (No Further Action) determination is based on the risk of exposure to any remaining contamination via the exposure pathways.

OPS has developed a four-tiered closure approach for petroleum releases.

- Multiple remedial actions may need to be completed to meet Tier I or II closure criteria, and it is possible that the petroleum release will not meet all of the criteria. Tier III or Tier IV closure criteria may be considered for a petroleum release that cannot achieve Tier I or II closure criteria.
- The requirements for the appropriate tier must be met prior to requesting NFA.

The information provided below is intended to assist in the evaluation of a release event based on risk to human health and the environment. Click on the arrows for more information.

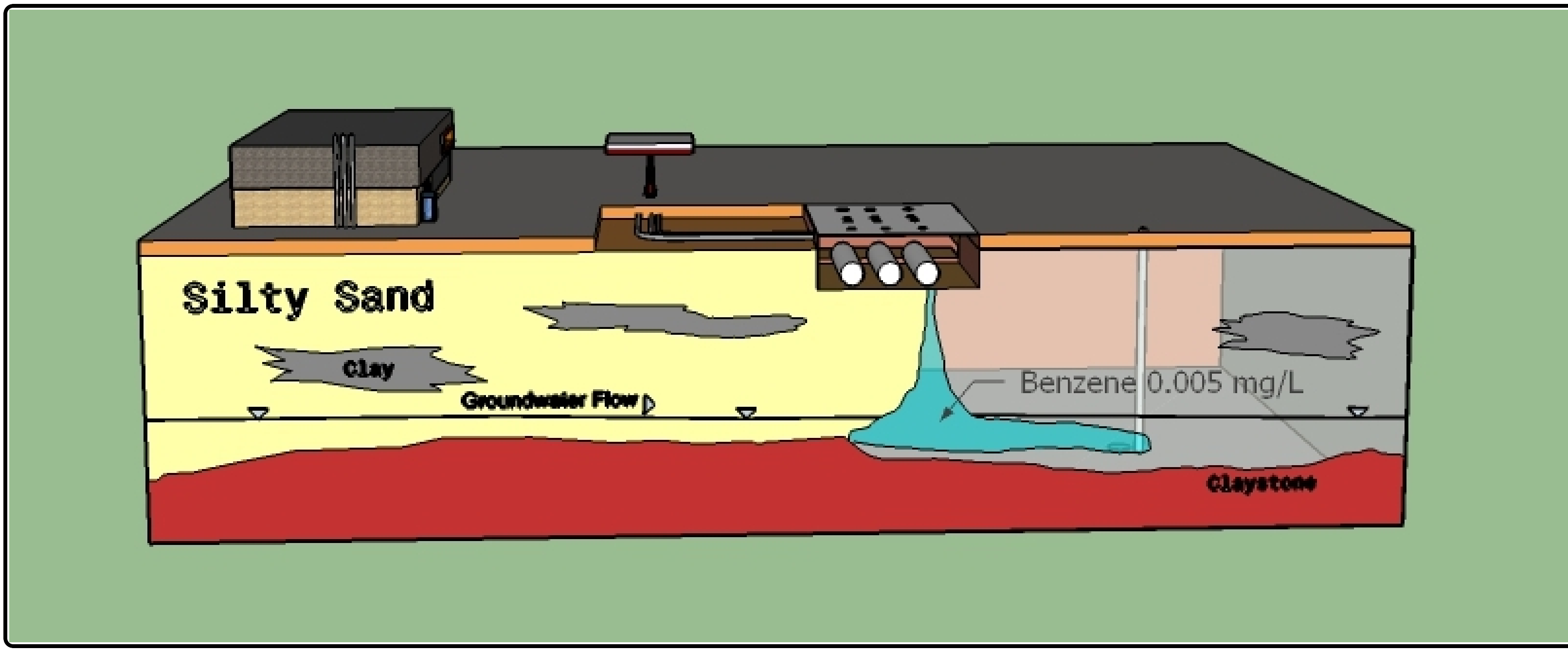
Obtaining a No Further Action Determination

Conducting site characterization that includes developing a conceptual site model is a prerequisite to requesting and issuing an NFA. OPS will issue an NFA letter once it has been demonstrated that the petroleum release is considered to be low-risk to human health and the environment. Presenting a well-developed CSM greatly enhances the likelihood of attaining an NFA determination. All NFA letters will indicate that the petroleum release was closed based on the information available at the time of the determination and on the existing exposure pathways' conditions. OPS will archive petroleum releases in the OPS database and will indicate the appropriate closure criteria. A petroleum release may be reopened if exposure conditions change.

Tier I Closure Criteria

OPS has established a Tier I RBSL for each primary and select secondary COC (chemical of concern) based on the exposure pathway. The Tier I RBSLs are the first level of standards to which you should compare soil and groundwater data to determine if remedial action is warranted. They are based on the EPA drinking water standard maximum contaminant levels. Soil and groundwater must be defined to a level below the Tier I RBSL for each COC found at the site.

Tier I evaluations involve a comparison of COC concentrations to Tier I RBSLs. No further action is appropriate for a release if all COCs are below the Tier I RBSLs.



Tier I scenario

If the Tier I closure criteria cannot be met, a Tier II closure evaluation would be the next step to take.

Tier II Closure Criteria

Tier II evaluations include the collection of site data to input into fate and transport model software for the development of SSTLs (site-specific target levels[1]). You may use Tier II evaluations to calculate on-site SSTLs for soil and

[1] A remediation target concentration that is developed using data collected from a site

groundwater, but you may not develop Tier II evaluations for off-site contamination or surficial soils.

Fate and Transport Modeling

Predictive fate and transport models utilize site-specific data to predict how the COCs will migrate through a particular medium over time. The resultant model is then compared to existing empirical site data as a form of validation.

Default input parameters and additional fate and transport modeling information can be found in the Fate and Transport Modeling section of the Site Characterization topic.

SSTLs (Site- Specific Target Levels)

You can develop SSTLs for on-site source areas where contamination remains above the Tier I RBSLs. You can derive Tier II SSTLs from the same equations used to calculate the Tier I RBSLs, but site-specific parameters are used in the calculations instead. The SSTL for a source area is the maximum concentration determined by a model that is predicted to be protective of the nearest POE (point of exposure) to the Tier I RBSL.

Once an SSTL is developed for a source location, compare it to the actual source data. Remedial action may be required if the actual source concentrations are above the calculated SSTL.

Exposure Pathway Elimination

Predictive fate and transport modeling and the development of SSTLs may be utilized as lines of evidence to eliminate an exposure pathway.

The following criteria are required for elimination of an exposure pathway to be considered valid under a Tier II fate and transport model.

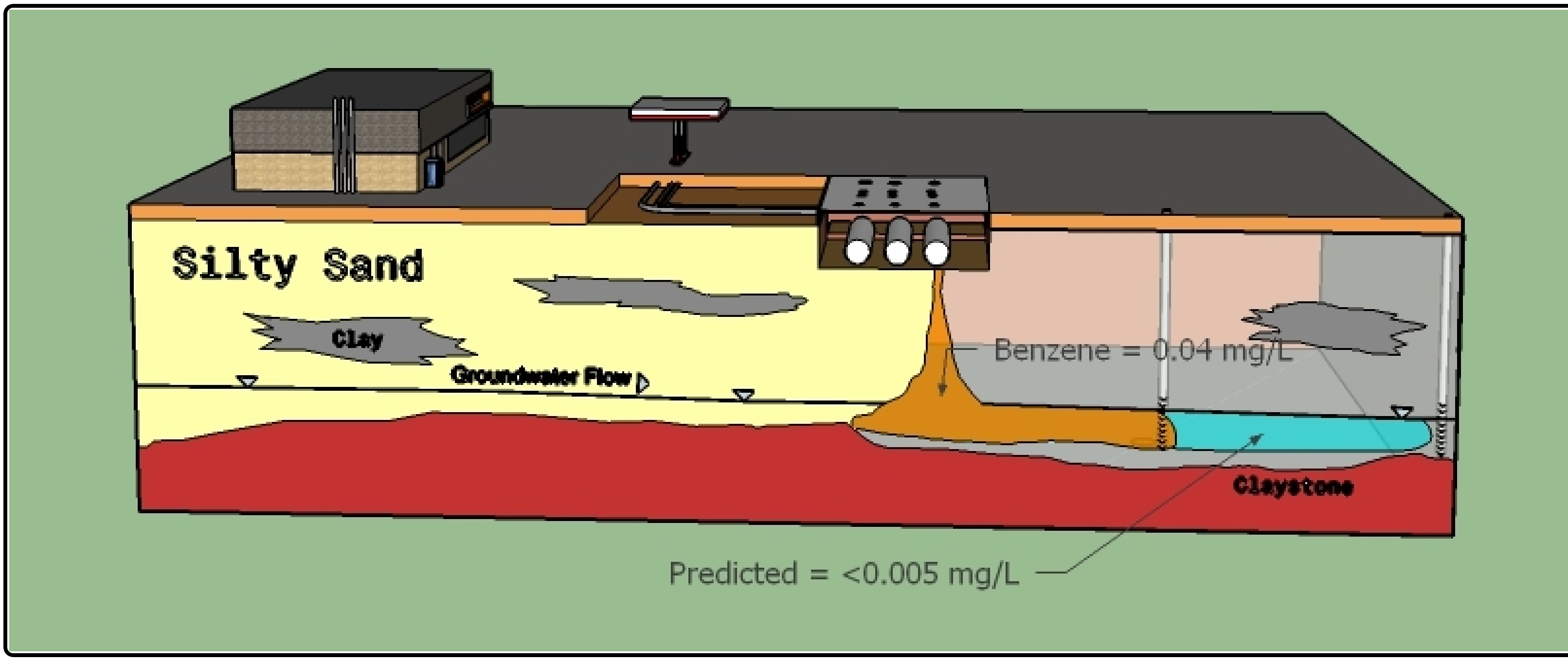
- POEs must not be impacted by any COC above the Tier I RBSLs.
- Point of compliance monitoring wells must be below the Tier I RBSLs at, or prior to, the nearest POE.

- LNAPL (light non-aqueous phase liquid) must be removed to the maximum extent practicable.
- The source COC concentration input values must be representative of the source area and not under the influence of a remedial method.
- Post-remediation environmental monitoring must be conducted for an adequate period of time to demonstrate that the dissolved-phase plume is stable or decreasing.

Tier II Closure Evaluation

NFA may be granted for a release when these three conditions are met.

- Impacted media concentrations are lower than SSTLs for the applicable exposure pathways.
- Point of compliance monitoring wells upgradient of the nearest POE are below the Tier I RBSLs.
- Fate and transport modeling predicts that POEs will not become impacted in the future at concentrations above the Tier I RBSLs.



Tier II scenario

Tier III Closure Criteria

Tier III closure criteria establish conditions where COCs can remain above Tier I RBSLs at the release property boundary but not beyond an adjoining public roadway.

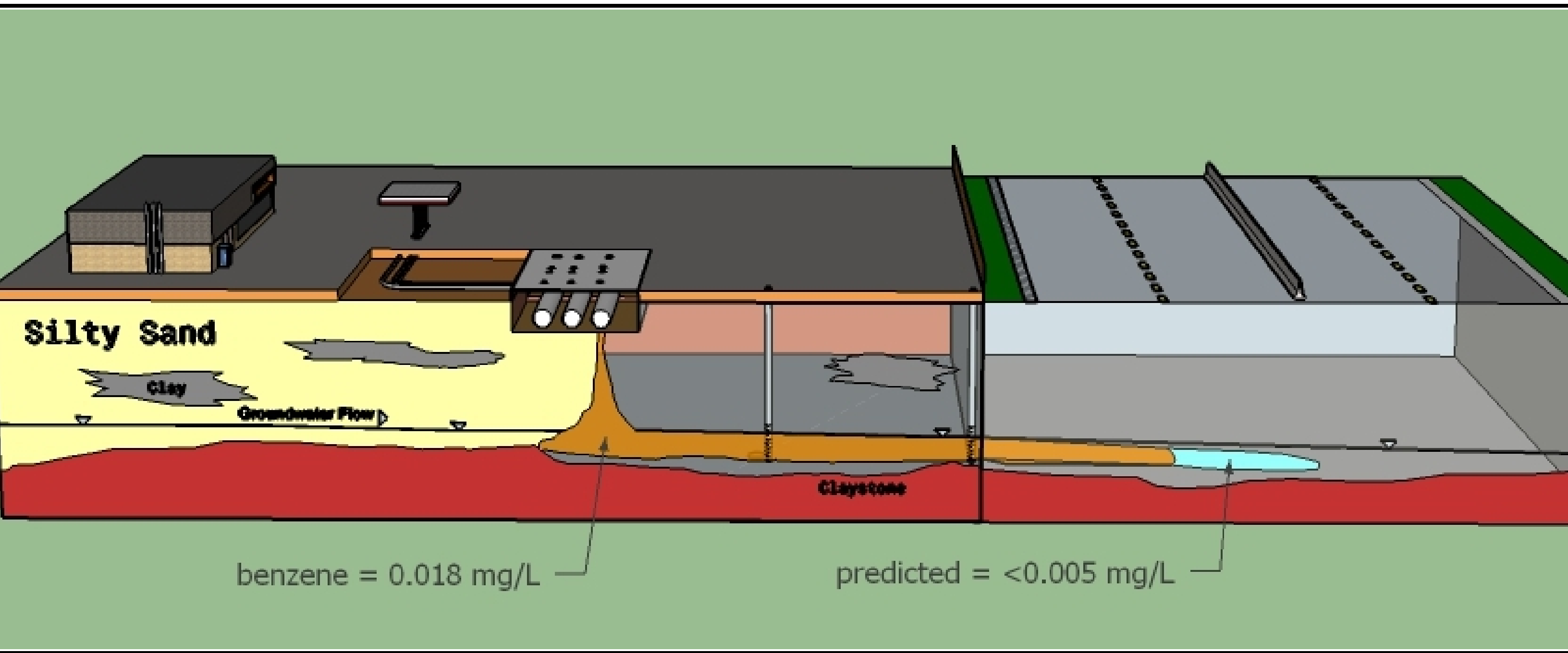
The following four criteria must be met for a petroleum release to be considered for Tier III closure.

- Contaminant Removal to the Maximum Extent Practicable
    - Source area removal, dissolved-phase remediation, LNAPL abatement and any other remedial activities must be completed per the approved CAP (Corrective Action Plan) and subsequent CAP Modifications. Contaminant mass estimates should be included to represent initial mass estimates, mass removed during remediation and mass remaining in place upon a closure request.
    - You may need to employ multiple remediation technologies to remove contaminant mass to meet the established remediation target goals. CAPs are not developed to meet Tier III removal criteria; instead, the goal of an approved CAP is to remediate impacted media to meet Tier I or Tier II closure criteria. Ultimately, a closure evaluation must indicate that contamination has been removed to the maximum extent practicable with consideration given to available technologies, costs and site logistics.
- Public Roadway Property Boundary is the Only Impacted POE
    - A public roadway is the only POE where COC concentrations may be above the Tier I RBSLs. Point of compliance well locations must be established immediately downgradient of the public roadway.
    - Present a summary of existing and planned construction activities along with an evaluation of how potential exposure pathways will be affected based on these activities.

- Post-Remediation Monitoring and Fate and Transport Modeling
  - Conduct post-remediation environmental monitoring for an adequate period of time to demonstrate that dissolved-phase plume sizes and trends are stable or diminishing. Predictive fate and transport modeling, as described under Tier II criteria, must demonstrate that off-site point of compliance monitoring wells will not be impacted above the Tier I RBSLs.
- Off-site Property Owner Notification
  - The owner/operator associated with the petroleum release should provide the property owner of the impacted public roadway with notification that contamination is (or is predicted to be) located beneath the public roadway.

Tier III Closure Evaluation

NFA may be granted for a release if the Tier III closure criteria are met. OPS will provide the Utility Notification Center of Colorado with the addresses and location of impacted properties closed under Tier III. This listing will provide information to the public on any respective exposures from petroleum contaminants left in place.



Tier III scenario

Tier IV Closure Criteria

Tier IV closure criteria establish conditions where COCs can remain above Tier I RBSLs at off-site properties, irrespective of land use.

The following criteria must be met for a petroleum release to be considered for Tier IV closure.

- No Active Storage Tank Systems
  - The property on which the petroleum release originated cannot have an active petroleum storage tank system.
- Contaminant Removal to the Maximum Extent Practicable
  - Source area removal, dissolved-phase remediation, LNAPL abatement and any other remedial activities must be completed per the approved CAP (Corrective Action Plan) and subsequent CAP Modifications. Contaminant mass estimates should be included to represent initial mass estimates, mass removed during remediation

and mass remaining in place upon a closure request.

  - You may need to employ multiple remediation technologies to remove contaminant mass to meet the established remediation target goals. CAPs are not developed to meet Tier IV removal criteria; instead, the goal of an approved CAP is to remediate impacted media to meet Tier I or Tier II closure criteria. Ultimately, a closure evaluation must indicate that contamination has been removed to the maximum extent practicable with consideration given to available technologies, costs and site logistics.

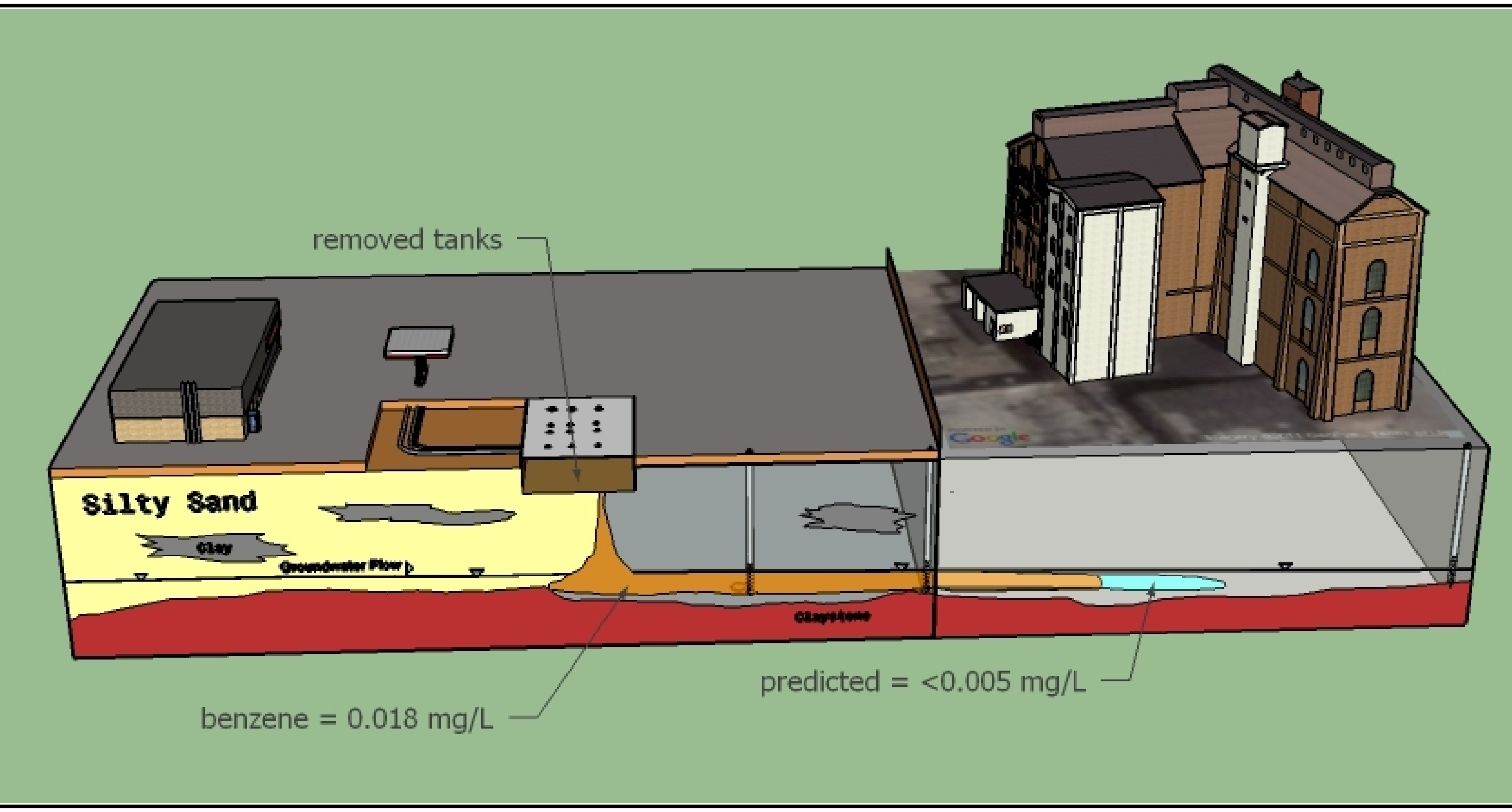
- The Property Boundary is the Only Impacted POE
  - A property boundary is the only POE where COC concentrations may be above the Tier I RBSL. Point of compliance locations must be established immediately upgradient of the nearest POE to the property boundary.
  - Present a summary of existing and planned site uses along with an evaluation of how potential exposure pathways will be affected based on the land use.

- Post-Remediation Monitoring and Fate and Transport Modeling

- Off-site Property Owner Notification
  - The owner or operator associated with the petroleum release should provide the property owners of the impacted property notification that contamination is or is predicted to be located beneath their property.

Tier IV Closure Evaluation

NFA may be granted for a release if the Tier IV closure criteria are met. OPS will provide the Utility Notification Center of Colorado with the addresses and location of impacted properties closed under Tier IV. This listing will provide information to the public on any respective exposures from potential petroleum contaminants left in place.



Tier IV scenario

Introduction - Why the Fund?

The Colorado Petroleum Storage Tank Fund (the Fund) provides financial assistance to petroleum UST (underground storage tank) owners and operators in Colorado who must comply with EPA (Environmental Protection Agency) financial requirements for UST operation. The Fund's purpose is to provide reimbursement for the assessment and cleanup of accidental releases of petroleum fuels from regulated fuel-storage tank systems.

Reimbursed costs may include:

- Emergency response activities
- Assessment activities to determine the extent of petroleum contamination
- Cleanup activities to remove petroleum contamination from the environment
- Impacts to third parties (with limitations)

The Fund is managed by the OPS (Division of Oil and Public Safety) Fund Section.

- The Colorado State Legislature created the Fund in 1989. It gained interim approval from the EPA as a Financial Responsibility mechanism in 1997 and formal approval in 2006. The Fund provides direct reimbursement to eligible Fund applicants and to State-Lead contractors.
- Monies in the Fund come primarily from the ERS (Environmental Response Surcharge). The amount of the ERS varies depending on the Fund balance - the ERS is lower when the Fund balance is higher.

Financial Responsibility

What is Financial Responsibility?

Owners/operators of regulated tank systems are required to have enough money available to clean up an accidental release of petroleum from their systems. Owners/operators meet this requirement by using a state fund, as in Colorado, or by using an insurance policy or other mechanism if a state fund is not available or if the tank owner is not eligible to use the state fund.

The financial requirement ranges from $500,000 to $2 million, depending on how much fuel the facility handles and the number of tanks the owner/operator manages. Federal regulations apply only to UST (underground storage tank) systems, but Colorado statutes apply the financial responsibility requirement to AST (aboveground storage tank) systems as well.

Colorado also allows other financial means (per Section 7-2 of the Colorado Petroleum Storage Tank Regulations), which may include:

- Self-insurance
- An insurance policy
- A letter of credit
- A trust fund
- A certificate of deposit
- Another secured financial instrument

The Fund may serve as the financial responsibility mechanism for most petroleum UST and AST owners/operators in Colorado. In order to utilize the Fund, the petroleum storage tank systems must be in operational compliance, and in the event of a release, owners/operators must apply for eligibility to the Fund to receive reimbursement.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ONE HUNDRED DOLLARS
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Fund Eligibility

When there is a **release**[1] to the environment from an underground or above-ground petroleum storage tank, the Fund may provide reimbursement for cleanup for certain tank owners/operators. This eligibility is primarily dependent on the tank compliance history.

Categories of Eligibility

There are two main categories of eligibility to the Fund. These include Responsible parties and Non-responsible parties. The Responsible party is the tank owner/operator. Parties in this category will have a $10,000 deductible imposed on their reimbursements. The Non-responsible category includes property owners,[2] orphaned[3] or abandoned[4] tank owners and lenders. No deductible is imposed on reimbursements for these Non-responsible parties.

Parties not eligible to the Fund include the following:

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[1] any spilling, leaking, emitting, discharging, escaping, leaching or disposing of a regulated substance from a regulated tank system into the environment

[2] a person having a legal or equitable interest in real or personal property that is subject to this article

[3] an underground storage tank which is: (a) Owned or operated by an unidentified owner as defined in this article; or (b) No longer in use and was not closed in accordance with the procedures required by this article and the property has changed ownership prior to December 22, 1988, and such property is no longer used to dispense fuels.

[4] an underground or aboveground petroleum storage tank that the current tank owner/operator or current property owner did not install, has never operated or leased to another for operation, and had no reason to know was present on the site at the time of site acquisition.

- Insurance companies
- Federal facilities
- Railroads
- Airports
- Neighboring property owners

Am I Eligible?

Choose the appropriate Responsible or Non-responsible party type below for details regarding how to establish eligibility and apply to the Fund.

Tank Owner or Operator Responsible for the Release

Establishing Eligibility

In order for a tank owner/operator to be eligible for reimbursement from the Fund, the tank owner/operator must:

- Be a current or former tank owner/operator of the site where the release occurred
- Request reimbursement for releases that were discovered on or after July 1, 1989, and for which expenses were incurred on or after July 1, 1989
- Have registered the tank(s) and paid the current and past annual tank registration fees on a timely basis for each petroleum storage tank
- Demonstrate that accurate and complete records are maintained for release detection and release prevention (when required by the Director)
- Comply with criteria for reporting a release to OPS
- Meet the owner/operator criteria for corrective action as established by the Director

- Be in substantial compliance with Colorado Petroleum Storage Tank regulations as determined by the Petroleum Storage Tank Committee
- Pay the environmental response surcharge that applies to petroleum products sold in Colorado and not be in default on any obligation caused by the environmental response surcharge
- Demonstrate evidence of financial responsibility of $10,000 for corrective action and $25,000 for compensation of third parties, personal injuries and property damage
- Demonstrate that deductible-allowable costs (release cleanup costs) of $10,000 and third-party liability costs of $25,000 per release occurrence for corrective action have been exceeded

Failure to meet these criteria may result in denial of eligibility or percentage reductions of any reimbursement award authorized by the Petroleum Storage Tank Committee.

Applying to the Fund

The documents listed below are required to support a request for eligibility as a tank owner.

- Original Application
- Release detection records and release prevention records (if OPS records are incomplete)

Orphaned or Abandoned Tank Owner

Establishing Eligibility

To establish Fund reimbursement eligibility as a tank owner, tank operator or property owner who bears no responsibility for the release when an orphaned or abandoned tank is involved, a tank owner/operator must provide proof that he or she:

- Did not install petroleum storage tanks on the property
- Never operated petroleum storage tanks on the property
- Never leased petroleum storage tanks on the property to another person for operation
- Had no reason to know[1] that a release had occurred on the site when the site was acquired
- Discovered the petroleum contamination after December 22, 1988
- Owns a property on which contamination originated from the orphan or abandoned petroleum storage tank(s) on the site
- Had no reason to know that the petroleum storage tank(s) existed on the site when the property was acquired

Applying to the Fund

The documents listed below are required to support a request for eligibility as an orphaned or abandoned tank owner.

- Original Application
- Affidavit: Orphan or Abandoned Tanks
- Copy of the deed showing when the property was acquired
- Copies of any leases whereby the property was leased to another person
- A brief chronology describing the circumstances under which the property was acquired, whether a site assessment was performed prior to acquisition of the property and how and when the abandoned tank(s) and the petroleum contamination were found

Current or Former Property Owner

[1] includes by personal knowledge or observation, representations by the seller or any other person, environmental assessments, reports, or any other means that there had ever been a release of petroleum product on this site.

Establishing Eligibility

To establish Fund reimbursement eligibility as a Non-responsible property owner who bears no responsibility for the release, a property owner must provide proof that he or she:

- Acquired the property no later than June 3, 1992
- Did not install petroleum storage tanks on the property
- Never operated petroleum storage tanks on the property
- Never leased petroleum storage tanks on the property to another person for operation
- Had no reason to know[1] that a release had occurred on the site when it was acquired
- Discovered the petroleum contamination after December 22, 1988
- Can confirm that the contamination originated from petroleum storage tanks on the property

Applying to the Fund

The documents listed below are required to support a request for eligibility as a property owner.

- Original Application
- Affidavit: Current/Former Property Owner (signed before a notary public)
- Affidavit: Property Owner (Inherited Property) (if the property was acquired by inheritance)
- Copy of the deed showing when the property was acquired
- Copies of any leases whereby the property was leased to another person

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[1] includes by personal knowledge or observation, representations by the seller or any other person, environmental assessments, reports, or any other means that there had ever been a release of petroleum product on this site.

- Evidence that tanks were present at one time (if tanks are no longer present on the property)
- A brief chronology describing the circumstances under which the property was acquired, whether a site assessment was performed before the acquisition and how and when the contamination was discovered

Lender

Establishing Eligibility

A lender must first establish eligibility to the Fund by obtaining a Certificate of Eligibility. The purpose of the Certificate of Eligibility is to encourage lenders to provide loans on properties with operative petroleum storage tanks and to ensure the lender's eligibility to the Petroleum Storage Tank Fund if the borrower defaults on the loan. The Certificate of Eligibility is only available to lenders and may be requested for any loan dated on or after September 30, 1995, on the property, whether or not it involves a property transfer. The Certificate of Eligibility must have been issued before the lender acquired the property through default.

A Certificate of Eligibility will only be issued if all of the following conditions have been met:

- The site is an operative site with underground or aboveground storage tanks
- The tank operator is operating the site in full compliance with Colorado Petroleum Storage Tank regulations
- Petroleum contamination does not exist on-site at the time the Certificate of Eligibility is issued
- The mortgage or loan is dated on or after September 30, 1995

To receive a Certificate of Eligibility, the lender must submit the following documentation:

- Certificate of Eligibility - Petroleum Storage Tank Status Sheet fully completed and signed by the lender and tank operator
- Tank Addendum that includes information on ALL underground and aboveground storage tanks on-site
- Site map showing the location of tanks and lines on the property
- Copy of the mortgage or loan

Applying to the Fund

To establish eligibility for reimbursement from the Fund as a lender who bears no responsibility for the release, the lender must submit the following documentation:

- Original Application
- Affidavit: Lender (signed before a notary public)
- A copy of the original loan which shows the date of the loan and any reassignments of that loan
- A copy of the foreclosure document or deed
- Evidence that tanks were present on the property at one time (if tanks were not present on the property at the time the property was acquired)
- A brief chronology of events related to the site history, when the lender acquired the property via foreclosure (or a deed in lieu of foreclosure), whether a site assessment was performed before the acquisition and how and when the contamination was discovered
- Documentation verifying the merger (if the lender acquired the property through a merger)
- A copy of the Certificate of Eligibility issued by OPS (if the original loan was dated after September 30, 1995)

Transferring Eligibility

Once established, Fund eligibility can be transferred to another party. A transfer usually occurs when a Responsible party wishes to sell the site before remediation is complete and transfer that eligibility to the buyer.

Any penalty reductions imposed on the original eligible party for regulatory non-compliance will transfer and apply to any subsequent buyers with respect to all remediation activities conducted through closure.

Eligibility established by Non-responsible parties can also be transferred to another party. However, eligibility established by a Non-responsible party cannot be transferred to any person who owned or operated tanks at the subject property at any time prior to the discovery of the contamination.

Request to Transfer Fund Eligibility

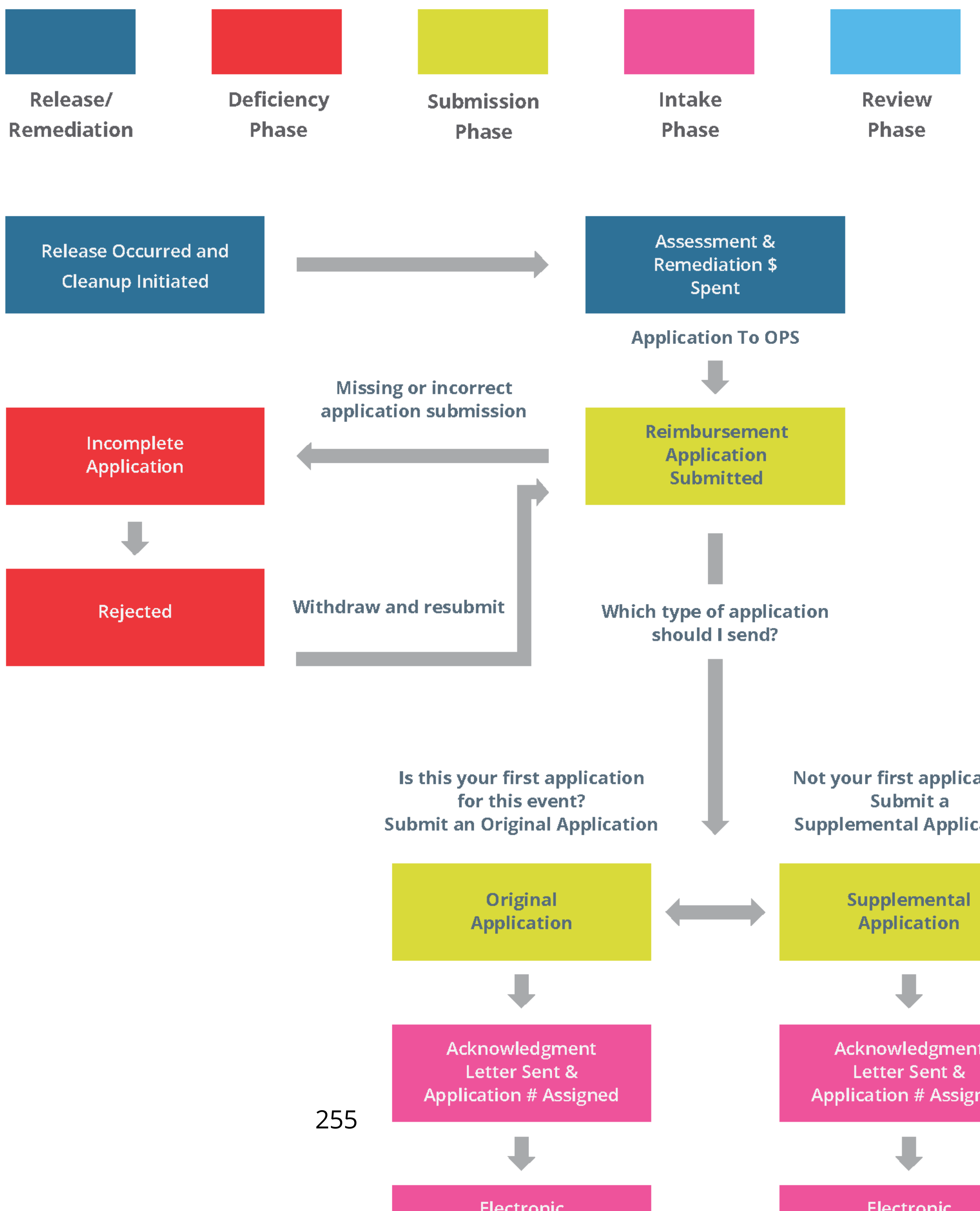
How Do I Get Reimbursed?

There are two types of applications used to request reimbursement from the Fund - the Original application and the Supplemental application. The Original application is the initial application used to establish Fund eligibility. Once eligibility has been established and the site has been approved by the Petroleum Storage Tank Committee, Supplemental applications are then submitted as necessary until the cleanup is complete.

Fund Process Flowchart

Click on the image below to see an overview of the Fund Application process.

Fund Flowchart



Frequently Asked Questions

When do I need to submit new tax information?

If the entity name, tax identification number, address or remit address changes from what was submitted on the Original application or the last time the tax information was submitted to OPS, a new W-9 and IRS documentation are needed. Any time a W-9 or other IRS documentation is submitted to OPS, it must be dated no older than 6 months before the time of submittal.

What kind of costs can I be reimbursed for?

Only allowable costs (costs incurred to clean up petroleum contamination) can be reimbursed. If there is no petroleum contamination, or if contamination levels are below established cleanup levels, no costs are allowable. The only exception is for investigation of suspected releases. If petroleum contamination levels only slightly exceed established clean-up levels, work with OPS Remediation Section Staff to make sure remediation is necessary before incurring costs.

Other reimbursement considerations are listed below.

- Tank removal and disposal costs are not allowable, and if requested for reimbursement, they are subject to a 100% penalty (unallowed costs will be doubled).
- For tank owners/operators, remediation costs pertaining to tanks permanently closed (whether removed or closed in place) before December 22, 1988, are not allowable.

For a complete list of allowable and not allowed costs see Article 8, Sections 8-3 and 8-4 of the Colorado Petroleum Storage Tank Regulations.

What should I do if I disagree with the final reimbursement amount?

If you dispute the amount you have been reimbursed, you may file a protest. The protest must be submitted within 60 calendar days of the date of the Fund

Payment Report.

How do I know if I need to include additional affidavits with the application?
Depending on an applicant's eligibility category, additional affidavits may be required. The most common affidavit is the Affidavit for Equipment or Materials Costing $10,000 or Over and is required for all equipment or materials installed or used on-site costing $10,000 or more, but is not needed for drilling or disposal costs.

All of the affidavits are available on the Fund Forms page. If you have questions about which affidavits you need to complete, please contact the Fund Section.

Is eligibility transferable?
Yes. If a person who has established Fund eligibility wishes to sell the site before the remediation is complete, the person may request to transfer his or her eligibility to the buyer, who would then be required to continue the cleanup. Any penalty reductions imposed on the original applicant for regulatory non-compliance will transfer and apply to any subsequent buyers with respect to all remediation activities conducted through site closure.

How can I get help preparing an application?
Although an applicant can prepare the application themselves, most applicants use the services of their environmental consultant or representative for application preparation. Recognized Environmental Professionals are familiar with the reimbursement process and preparation of properly completed applications. Additionally, OPS Fund and Remediation staff members are always available to guide an applicant through the reimbursement process and answer any questions.

Original Application

The Original Application form, which is in Excel format, contains detailed instructions for completion.

The Original application is used to establish eligibility, so it is important to submit the application with the correct eligibility category. The majority of applicants to the Fund are in the tank owner/operator category. Selection of the proper Non-responsible party category may be more difficult. Please contact the Fund Section if you need direction with regard to choosing the proper eligibility category.

Please note that the final eligibility category is determined by the Petroleum Storage Tank Committee and may differ from the category that the applicant requested on the Original application.

Submitting Costs with an Original Application

When submitting costs with any Original Application (whether you're a Responsible tank owner/operator or a Non-responsible party), the following supporting documentation is required.

- Listing of Costs (part of Original Application)
- All invoices and backup documentation that are requested for reimbursement on the Listing of Costs
- Affidavit: Proof of Payment
- Other affidavits as appropriate

Submitting Insurance and IRS Documentation with an Original Application

The following documents are required.

- Affidavit: Insurance Documentation
- Other affidavits as appropriate
- W-9 & IRS documentation (with Original Application or any time there is a change to this information)

Tips for Completing the Original Application

- Ensure all names and titles follow the signature requirements.
- Submit the application in the correct order.
- Ensure the required file naming convention is followed.
- Submit all required documentation.
- Submit a complete and correct eRAP[1].

Original Application Example

What Happens Next?

After the application has been received, the Fund Analyst, Technical Reviewer and Compliance Reviewer will examine the application and supporting documentation. If documentation is missing or submitted incorrectly, the Fund Analyst will issue a deficiency letter called a RAP Deficiency Review that lists the reasons why the application cannot continue to be processed. The 90-day processing clock stops when a deficiency is issued.

Once the deficiency has been satisfied, the application is placed back in the Fund Analyst's queue and the 90-day processing clock is restarted from the beginning. The application review is then completed and any recommended percent reductions for non-compliance are identified on the ESS (Event Summary Sheet). The Fund Analyst then schedules the application to be heard before the PSTC (Petroleum Storage Tank Committee). Once scheduled, the PSTC Organizer will notify the applicant and consultant that the application has been scheduled for PSTC review. The applicant and consultant will receive a copy of the ESS via email for review at this time.

At their monthly meeting, the PSTC makes the decision whether to approve the applicant's eligibility and impose any percent reductions for non-compliance. If

[1] electronic reimbursement application

percent reductions for non-compliance are imposed at the time that the PSTC approves the Original application, these percent reductions will apply to all future reimbursement applications for that event. The PSTC authorizes payment by issuing a Fund Payment Report with payment issued within 30 days from the PSTC meeting date.

Supplemental Application

The Supplemental Application form, which is also in Excel format, contains detailed instructions for completion.

Tips for Completing the Supplemental Application

- Ensure all names and titles follow the signature requirements.
- Submit the application in the correct order.
- Ensure the required file naming convention is followed.
- Submit all required documentation.
- Submit a complete and correct eRAP.

Supplemental Application Example

What Happens Next?

The application review is completed and a Fund Payment Report is issued with payment issued within 30 days from the date of the Fund Payment Report. If documentation is missing or submitted incorrectly, the Fund Analyst will issue a deficiency letter called a RAP Deficiency Review that lists the reasons why the application cannot continue to be processed and the 90-day processing clock stops. Once the deficiency has been satisfied, the application is placed back in the Fund Analyst’s queue and the 90-day processing clock is restarted from the beginning.

How Payments are Made

Fund payments (reimbursements) are authorized by the generation of an FPR (Fund Payment Report). Once the Fund Analyst completes the reimbursement application review, an FPR is created and sent to the Applicant which details the following information:

- Site information
- Amount submitted for reimbursement
- Application preparation costs (4z costs), if submitted
- Any percent reductions for non-compliance
- Other reductions, such as the $10,000 deductible for Original applications or fees/penalties due

Once the Fund Section Supervisor approves the FPR, it goes to the CDLE (Colorado Department of Labor and Employment) Finance department. Fund Section staff will then email the FPR to the Applicant and to the Applicant's representative who is designated on the application. The CDLE Finance department authorizes the direct deposit to the Applicant's bank account or generates a warrant (check).

Payment by Direct Deposit via Electronic Funds Transfer (EFT)

The CDLE Finance department initiates the process of making direct deposits into an Applicant's bank account by creating a payment voucher which must be issued within 30 calendar days of the date of the FPR. The funds are transferred into the Applicant's bank account on the following day.

To authorize EFT payments, an Applicant needs to complete an EFT Direct Deposit Authorization Form. The estimated time for payment via EFT is shortened with usage of a direct deposit versus payment by warrant. When Fund staff send the FPR to the Finance department, the Fund staff provides a remittance file to the Applicant via email so that the Applicant is aware that a direct deposit payment is on the way. The remittance file details all payments for the applicant authorized on that particular date and the total amount of the deposit. If an Applicant is receiving payment for multiple applications, the direct deposit amount will be the total of all the applications.

Further details about establishing an EFT account

Payment by Warrant

The Finance department initiates this process by creating a payment voucher for the payment amount authorized by the FPR. The payment voucher must be issued within 30 calendar days of the date of the FPR. The warrant is then issued the following day and mailed to the Applicant via postal mail. Although the warrant is always addressed to the Applicant, a payment by warrant can be mailed to an address for someone other than the Applicant. To authorize the warrant to be sent to a different address, the Applicant needs to complete IRS form W-9 and place the name and address of the remit entity in the Address box on the left-hand side of the form. The Applicant's address is then placed in the Purchase Order box on the right-hand side of the form. Submit the completed W-9 form to the Fund Section when it is complete. An example of a completed W-9 form is included in the Original Application Example in the How Do I Get Reimbursed? guidance topic.

When Interest is Due to the Applicant

Interest is due to an applicant if the Fund Section does not process the reimbursement application within 90 working days of receipt or if payment is not made within 30 calendar days of the date of the FPR.

While it is extremely rare, interest due to the applicant is calculated by adding the amount of the payment and the Prime interest rate plus 3 points for every day past the close of the respective application or payment processing window. This calculation would be shown on the FPR and would result in a payment increase.

Vendor Offsets

Vendor Offset is a system the State Controller uses to recover any debts owed to the State for any State Agency. For example, if a Fund applicant owes taxes to the Department of Revenue, the reimbursement payment the Applicant receives from the Fund will be reduced to cover the taxes. The State Controller's office will notify the applicant of this "offset" via mail.

How to Protest a Fund Payment Report

Following decisions made by the PSTC (Petroleum Storage Tank Committee), an OPS Fund Analyst or Remediation Section Technical Reviewer, the Fund Section will send the Applicant an FPR (Fund Payment Report) documenting these decisions. Any unallowed costs will be accompanied by a brief statement providing the reasons why the costs are unallowed. If the Applicant reviews the FPR and is dissatisfied with any of these decisions, the Applicant can dispute the decisions by filing a Protest of Fund Payment Report form within 60 calendar days of the date of the FPR. If the Applicant does not file a written protest within the 60 calendar days, the Applicant will have waived his or her right to object to anything covered by the FPR. At this point everything regarding the application, including the amount of reimbursement and percentage reductions (which includes any reductions applicable to future applications), will be deemed final.

What can be protested?

Protests can be submitted to dispute:

- The eligibility determination made by the PSTC.
- The percent reductions imposed at the time of the Original application.
- Any unallowed costs that reduce the reimbursement received. Sections 8-3 and 8-4 of the Colorado Petroleum Storage Tank regulations provide details regarding allowed and unallowed costs.

What cannot be protested?

Out-of-scope CAP (corrective action plan) costs are considered not eligible for reimbursement. Protests may not be filed for CAP costs that are considered out-of-scope or that exceed the phase of work budgeted for an approved CAP or CAP modification and the associated Economic Feasibility Summary. Section 8-2 (c) in the Colorado Petroleum Storage Tank regulations provides the authority for the not eligible determination. If a protest is received for not eligible costs, it will be returned to the Applicant.

Filing a Protest

To file a protest, complete the Protest of Fund Payment Report form.

Keep the following in mind when completing the form.

- Protests must be submitted within 60 calendar days from the date of the FPR.
- Any protests received after the 60 calendar days will be dismissed.
- The Protest of Fund Payment Report form must be signed by the Applicant who signed the Reimbursement Application.
- A clear statement of each item being disputed on the FPR must be included in section 5 on the Protest of Fund Payment Report form, and any relevant supporting documentation should be submitted with the form (see the example below).

STATEMENT OF PROTEST

(Clear statement of each item being disputed on the PSTC Fund Payment Report – Attach a copy of the Fund Payment Repo

e item being disputed is the unallowed lodging costs due to no documentation. The lodging eipt has been provided with this protest as evidence of lodging costs as provided in the plication for reimbursement.

Submit the completed Protest of Fund Payment Report electronically as a PDF to cdle_petroleumstoragetankcommittee@state.co.us.

What to expect after a Protest has been filed

- The Applicant and the Consultant will receive an acknowledgment letter from the Fund stating that the protest has been received.

- The protest will be assigned a number that will be used on all future correspondence.
- The Fund Analyst or Remediation Technical Reviewer will review the protest and any supporting documentation and make one of the following recommendations to the PSTC.

Recommendation	Recommendation Description
Full Payment	Full payment of protested costs will be issued, along with a final determination letter which will resolve and close the protest.
Partial Payment	A settlement agreement for a partial payment will be prepared by the Attorney General's office and signed by both OPS and the Applicant, which will resolve the matter and close the protest.
Dismissal	If OPS determines that payment will

	not be made for the protested costs, the protest will be sent to the Attorney General's office for dismissal. The Attorney General's office will prepare the Motion To Dismiss and notify the Applicant. The Applicant must respond by the deadline if the Applicant wishes to schedule a formal hearing before the PSTC to dispute the protest dismissal.

Audits

Audits

In order to ensure the integrity of the reimbursement process, Petroleum Storage Tank Fund Auditors will periodically conduct audits focused on two key areas - the Fieldwork Audit and the Site Audit.

The **Fieldwork Audit** verifies the costs requested for reimbursement to ensure they conform to the agreed-upon scope of work and that the tasks performed were necessary for remediation of the site.

The **Site Audit** verifies that the remediation equipment is installed and operable and that the remediation work necessary to install the equipment was performed.

The Fieldwork Audit may be conducted concurrently with the Site Audit, or the two audits may be conducted separately.

Who and what is audited?

Petroleum Release events where reimbursement applications (RAPs) have been submitted may be audited, and these audits may involve participation from Responsible Parties, their Consultants, or both.

Fund Audit Process

The chart below provides an overview of the steps in the Fund Audit process. Click on the tabs beneath the chart for more details about each step.

Fund Audit Pr

Scheduling

- The Fund Auditor will send an email to the Auditee phone interview.
- The preliminary phone interview will be conducted
- After the preliminary phone interview, the Fund Au discuss audit specifics.

Fieldwork Audit

- The Fund Auditor will interview the Auditee's mana procedures for data entry, analysis and reporting.
- The Auditor will review documentation for evidenc manner.

Site Audit

- The Fund Auditor and Technical Reviewer will verif operable.
- The Fund Auditor will evaluate whether the remed performed coincides with the information in the RA

Reporting

- The Fund Auditor will send an Audit Report detailin
- The Audit Report will identify the Auditee's best pr
- The Auditee will have an opportunity to respond to

Scheduling the Audit

The Fund Auditor will contact the Auditee to schedule the audit.

Email and Phone Interview

Initially, the Fund Auditor will send the Auditee an “Intent to Audit” email to notify the Auditee that he/she has been selected for an audit and to schedule a preliminary phone interview.

The Intent to Audit email also includes the list of items the Fund Auditor will discuss with the Auditee during the preliminary phone interview. These items are listed below.

- Who are the officers at the Auditee’s organization?
- Which officer at the Auditee’s organization will sign the Management Representation Letter[1]?
- Which officer at the Auditee’s organization will represent the organization at the Auditor's interview of management?
- What is the organization's structure (including field personnel, administrative/accounting personnel and management)?
- What internal controls are in place to ensure integrity and consistency when constructing a RAP - from field tasks to application completion?
- What are the Auditee organization's source documents or records (field logs, methods of time tracking, accounting software and reports, etc.)?
- Which personnel will be available for documentation review, walk-through testing, or both?

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[1] The letter that confirms the Auditee provided the Fund Auditor with access and full disclosure of all significant facts; the Fund Auditor will send a copy of the letter to the Auditee’s organization when the audit is scheduled.

• Where is the Auditee's organization located (the place were RAPs are administrated and source documents and records are housed)?

Setting the Audit Date

After the preliminary phone interview, the Fund Auditor will contact the Auditee to schedule the audit, providing the following audit details:

• The audit date
• The approximate length of time the audit will take
• The audit objective(s) and proposed method
• A description of the Auditee's expected participation and the type(s) of audit(s) to be performed (fieldwork, site, or both)
• The documentation the Auditee will be required to provide (labor detail, original invoices and cancelled checks, etc.)

Fieldwork Audit

The Fieldwork Audit will include an interview with the Auditee's management, and potentially with hands-on personnel, regarding the organization's internal controls (including recordkeeping/accounting systems and procedures for data entry, analysis and reporting).

Documents Involved

The Fund Auditor may request that the Auditee provide the following source documents and records to provide reasonable assurance that the costs are correct for work that was done.

• General Ledger
• Accounts Payable
• Accounts Receivable
• Payroll
• Job Cost Accounting Reports

• Statements/Invoices to Clients
• Supplier/Subcontractor Backup Statements/Invoices
• Deposit Slips
• Canceled Checks
• Time Keeping and Equipment Logs (i.e., time cards, job logs and field notes)
• Any other documentation discovered in the interview with management regarding recordkeeping/accounting systems and internal control procedures

Walkthrough Testing

The Fund Auditor may shadow the Auditee's internal control process to determine whether they function efficiently.

Fund Auditor Review

The Fund Auditor will also identify and test procedures and review the requested documentation to determine whether the internal controls operate effectively and efficiently.

This evaluation will occur at the OPS office using the internal control documents and information gathered at the Auditee's location.

Site Audit

The Site Audit is a quantifiable visual inspection of the remediation equipment in place at the Event location.

The Event's Technical Reviewer will observe and evaluate the remedial system, and the Fund Auditor will verify whether the documentation submitted in support of the RAP(s) for reimbursement substantiates the need for the equipment installed and remediation work that has been performed.

The Fund Auditor will evaluate the Site Audit information at the OPS office following the visit to the facility.

Reporting

Once the Fund Auditor completes the evaluation of the information gathered during the audit, the Fund Auditor will generate an Audit Report to present the findings to the Auditee.

The components of the Audit Report are as follows:

- An evaluation of audit evidence, compared against the audit criteria and objective(s)
- A determination of whether the audit criteria were met
- An identification of the Auditee's best practices and potential areas of improvement

The Auditee will receive a copy of the Audit Report and will have an opportunity to respond.

The results of the audit will also be presented to the **Petroleum Storage Tank Committee**[1].

[1] The Petroleum Storage Tank Committee (PSTC) is comprised of seven members who have technical expertise and knowledge in the fields related to corrective actions taken to mitigate underground and aboveground storage tank releases. The three permanent members are the Director of the Division of Oil and Public Safety (or designee), the Executive Director of the Department of Labor and Employment (or designee), and a petroleum storage tank owner/operator. The other four members on the committee may represent one of the following groups: Fire protection districts, elected local governmental officials, companies that refine and retail motor fuels in Colorado, companies that wholesale motor fuels in Colorado, owners and operators of independent retail outlets, companies that conduct corrective actions or install and repair underground and aboveground storage tanks and private citizens or interest groups.

Petroleum Cleanup and Redevelopment Fund

Petroleum Cleanup and Redevelopment Fund

Forms

Already familiar with the guidance and just need some forms?

Ownership and Operation Forms

- Install/Upgrade form - Use this form for all new installations or **upgrade**[1]s
- Minor Equipment Repair/ Replacement notification - Use this form for **repair**[2] or **replacement**[3] of existing spill containment at fill or vapor recovery connections, existing overfill protection devices and for existing submersible turbine pumps, under-dispenser containment or transition sumps. This form often accompanies the Tightness Testing for Secondary Containment form.
- AST/UST Registration forms - These forms are required within 30 days of delivering fuel to the tanks.
- AST/UST Transfer of Ownership forms - This form is required whenever tank systems are bought/sold.

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[1] the addition or retrofit of some systems (such as cathodic protection, lining, modification of the system piping, or spill and overfill controls, etc.) to improve the ability of an UST or AST system to prevent the release of product

[2] to restore to proper operating condition a tank, pipe, spill prevention equipment, overfill prevention equipment, corrosion protection equipment, release detection equipment or other system component that has caused a release of product from an AST or UST system or has failed to function properly

[3] This term applies to underground storage tanks and piping. For underground storage tanks – Replace means to remove an existing underground storage tank and install a new underground storage tank. For underground piping – Replace means to remove and put back in any amount of piping connected to a tank system. The secondary containment requirements for replaced piping are triggered when a minimum of 50% or 50 feet (whichever is less) of the total length of piping connected to a single tank is replaced. The total length of piping connected to a single tank includes the length piping from that tank to the farthest connected dispenser, including piping runs between dispensers connected to that tank.

- Change of Product - This form is required whenever there is a change to the regulated substance stored in a tank system. If the change of product involves **Alternative**[1]/**Renewable fuels**[2], you will also need to submit the Alternative/Renewable Fuel Compatibility form.
- AST/UST Temporary Closure forms - This form is required for putting a tank system in **temporary closure**[3]. It must be accompanied by records documenting the prior 12 months of release detection and corrosion protection testing (if applicable) for tanks and lines. If those records are not available, the tank system owner may conduct a precision tightness test on the tanks and lines and complete a site assessment and submit those results with the temporary closure notification
- AST/UST Back in Service forms - This form is required within 30 days of bringing a temporarily closed tank system back into use. It **must** be accompanied by passing tightness tests, including ullage, for the tanks and lines, conducted within the past 30 days.
- UST A&B Operator Designation form - Every UST system must have at least one A and B Operator. Use this form to designate the Operators for your tank system.

Inspection, Release Detection, and Corrosion Protection forms - These forms are made available for you to document your inspection, release detection and corrosion protection requirements. Other forms may be used as long as they contain the information on these forms.

Release Response Forms

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[1] motor fuel that combines petroleum-based fuel products with renewable fuels

[2] a motor vehicle fuel that is produced from plant or animal products or wastes, as opposed to fossil fuel sources.

[3] a period of time that a storage tank is empty but is not permanently closed or has not changed service to store a non-regulated substance. This term does not apply when a tank system is emptied for repair.

These forms are available to report a surface spill/release, for Site Characterization Reports (due within 180 days of release discovery), Corrective Action Plans (due within one year of release discovery), and Monitoring and Remediation Reports. The Recognized Environmental Professional application and associated forms are found here.

Reimbursement Forms

Original and supplemental reimbursement application forms, affidavits, and other associated forms for requesting reimbursement are found here.

Ownership and Operation

Ownership and Operation Forms

Reimbursement

Reimbursement Forms

Release Response

OPS requires that all electronic correspondence and reports addressed to the Remediation Section must be uploaded to the OPS FTP (File Transfer Protocol) site using the FTP instructions.

Report Formats

Combined Report (SCR\MRR\NFAR) - includes the SCR (Site Characterization Report), MRR (Monitoring and Remediation Report) and NFAR (No Further Action Request) report formats and it replaces all previous versions of the SCR, MRR and NFAR report formats. For the functions of the report to operate correctly, the files must be opened and saved in Microsoft Excel 2007.

Combined Report Instructions

Corrective Action Plan Report (CAP\EFS\MNA Tool) - must be used for all CAP and CAP Modification submittals

Corrective Action Plan (CAP) Instructions

Economic Feasibility Summary (EFS) Instructions

MNA Tool Instructions

Surface Release Characterization Reports are to be utilized if a surface release of less than 100 gallons of product was released and the released product did not come into contact with surficial soil, surface water, groundwater, or a storm water collection system that discharges to surface water or a sensitive environment.

Surface Release Characterization Report

Colorado Storage Tank Information System (COSTIS)

Click here to access the Colorado Storage Tank Information System (COSTIS).

A

Alternative

motor fuel that combines petroleum-based fuel products with renewable fuels

AST

All aboveground storage tanks at a facility, all the connected piping and ancillary equipment, all loading facilities, and all containment systems, if applicable

ASTs

All aboveground storage tanks at a facility, all the connected piping and ancillary equipment, all loading facilities, and all containment systems, if applicable

attenuation factor

The shallow soil vapor concentration divided by the deep soil vapor concentration.

C

Community Engagement Plan

The process of communicating with local residents and other stakeholders to: provide information throughout the investigation and cleanup of a contaminated site; provide opportunities for offering input about site investigation/cleanup plans; and to facilitate the resolution of community issues related to a contaminated site) provides site-related information to the community in a formal and coordinated manner. Community engagement is not a one-time event. There should be continuous communication between the tank owner, OPS, and affected property owners throughout all phases of the project; investigation, mitigation, and remediation.

confirmed

Direct evidence of regulated substance outside the tank system. Direct evidence includes detection of chemical compounds in soil or groundwater, observation of fuel outside the storage tank system, identification of contamination during tank system repairs, installation, replacement or other sub-pavement work, or the identification of regulated substance in soil, basements, utility lines or on surface water, in groundwater or in water wells. Confirmed releases include surface spills on or off pavement that are not cleaned up within 24 hours or are greater than 25 gallons.

F

false positive results

Detection of contaminant concentrations that is not represented by the media sampled, such as from cross-contamination or alternate sources of contamination.

L

lateral

the horizontal distance from the edge of a petroleum vapor source (LNAPL or dissolved phase plume) to the edge of a building foundation (ITRC PVI Guidance, 3.1.5, EPA PVI Guidance 4)

LNAPL Transmissivity

LNAPL transmissivity is a measure of lateral mobility of free-product hydrocarbon liquid within the groundwater environment.

Owner

(1) In the case of an underground storage tank in use on or after November 8, 1984, or brought into use after that date, any person who owns an underground storage tank used for the storage, use, or dispensing of regulated substances; (2) In the case of an underground storage tank in use before November 8, 1984, but no longer in use on or after November 8, 1984, any person who owned such tank immediately before the discontinuation of its use; or (3) Any person who owns an aboveground storage tank. (4) Regarding reporting and responding to releases of regulated substances, Owner means the person who owned the tank system at the time of the release. The term "owner" does not include any person who, without participating in the management of an underground storage tank and otherwise not engaged in petroleum production, refining, and marketing, holds indicia of ownership primarily to protect a security interest in or lien on the tank or the property where the tank is located.

Owner/operators

either the owner or the operator

owners or operators

Any person who owns an underground storage tank used for the storage, use, or dispensing of regulated substances. Any person who owns an aboveground storage tank. Regarding reporting and responding to releases of regulated substances, Owner means the person who owned the tank system at the time of the release. The term "owner" does not include any person who, without participating in the management of an underground storage tank and otherwise not engaged in petroleum production, refining, and marketing, holds indicia of ownership primarily to protect a security interest in or lien on the tank or the property where the tank is located.

P

person

A “person” is an individual, trust, firm, joint stock company, federal agency, corporation, state, municipality, commission, political subdivision of a state, or any interstate body. "Person" also includes a consortium, a joint venture, a commercial entity

Petroleum Storage Tank Committee

The Petroleum Storage Tank Committee (PSTC) is comprised of seven members who have technical expertise and knowledge in the fields related to corrective actions taken to mitigate underground and aboveground storage tank releases. The three permanent members are the Director of the Division of Oil and Public Safety (or designee), the Executive Director of the Department of Labor and Employment (or designee), and a petroleum storage tank owner/operator. The other four members on the committee may represent one of the following groups: Fire protection districts, elected local governmental officials, companies that refine and retail motor fuels in Colorado, companies that wholesale motor fuels in Colorado, owners and operators of independent retail outlets, companies that conduct corrective actions or install and repair underground and aboveground storage tanks and private citizens or interest groups.

POE

Point of Exposure - the location at which a person or sensitive environment is assumed to be exposed to a chemical of concern.

POEs

The location at which a person or sensitive environment is assumed to be exposed to a chemical of concern.

points of compliance

a location at which empirical data can be collected to demonstrate that an associated POE is not impacted or threatened to be impacted by the release

precluding factors

Preferential pathways that intersect the contaminant source and the building foundations that allow for preferential vapor flow into a structure such as utility corridors, trenches, elevator pits, sumps, drainage pits, and backfill with a greater porosity than the surrounding native material.

PVI

petroleum vapor intrusion

R

regulated storage tank systems

Underground Storage Tank (UST) system means any one or combination of tanks, including underground pipes, except those exempted in statute and these regulations, that is used to contain an accumulation of regulated substances and the volume of which, including the volume of underground pipes, is ten percent or more beneath the surface of the ground and is not permanently closed. Aboveground Storage Tank (AST) system means all ASTs at a facility, all the connected piping and ancillary equipment, all loading facilities, and all containment systems if applicable.

regulated substance

"Regulated substance" for UST systems has the same meaning as in C.R.S. § 8-20.5-101(13) as follows: (1) Any substance defined in section 101 (14) of the federal "Comprehensive Environmental Response, Compensation, and Liability Act of 1980", as amended, but not including any substance regulated as a hazardous waste under subtitle (C) of Title II of the federal "Resource Conservation and Recovery Act of 1976", as amended. 7 (2) Petroleum, including crude oil or any fraction thereof that is liquid at standard conditions of temperature and pressure (60 degrees Fahrenheit and 14.7 pounds per square inch absolute). (3) Alternative fuel (4) Renewable fuel “Regulated substance” for AST systems means regulated fuel products as defined in C.R.S. § 8-20.5-101(6), including alternative fuels and renewable fuels as defined in CRS 8-20.5-101(2.5) and (14.5) as follows: (1) All gasoline, aviation gasoline, diesel, aviation turbine fuel, jet fuel, fuel oil, biodiesel, biodiesel blends, kerosene, all alcohol blended fuels, gas or gaseous compounds, and other volatile, flammable, or combustible liquids, produced, compounded, and offered for sale or used for the purpose of generating heat, light, or power in internal combustion engines or fuel cells, for cleaning or for any other similar usage. (2) Alternative fuel (3) Renewable fuel

release

any spilling, leaking, emitting, discharging, escaping, leaching or disposing of a regulated substance from a regulated tank system into the environment

Renewable fuels

a motor vehicle fuel that is produced from plant or animal products or wastes, as opposed to fossil fuel sources.

Repair

to restore to proper operating condition a tank, pipe, spill prevention equipment, overfill prevention equipment, corrosion protection equipment, release detection equipment or other system component that has caused a release of product from an AST or UST system or has failed to function properly

replace

This term applies to underground storage tanks and piping. For underground storage tanks – Replace means to remove an existing underground storage tank and install a new underground storage tank. For underground piping – Replace means to remove and put back in any amount of piping connected to a tank system. The secondary containment requirements for replaced piping are triggered when a minimum of 50% or 50 feet (whichever is less) of the total length of piping connected to a single tank is replaced. The total length of piping connected to a single tank includes the length piping from that tank to the farthest connected dispenser, including piping runs between dispensers connected to that tank.

S

Sensitive environments

An area of particular environmental value where regulated petroleum contamination could pose a greater threat than in other less sensitive areas.

Site Check

collecting soil and/or groundwater samples for laboratory analysis from locations most likely to demonstrate the presence of a release from a regulated storage tank system.

spill bucket

A spill bucket is a liquid-tight container that surrounds the fill pipe of an UST. Its purpose is to catch and contain any small drips and spills from the delivery hose that may occur during the fuel delivery process.

suspected

Indirect evidence of a release such as a failed line or tank tightness test, unusual operating conditions, water in the tanks if the tanks do not test liquid-tight, inventory loss identified by leak detection equipment, inconclusive or failed SIR results or fuel in secondary containment (in contact with penetration points) or in damaged spill buckets. Suspected releases must be addressed by a system test or site check.

System Test

a test of tank system components, including any associated delivery piping, secondary containment or spill control component, to identify releases of regulated substances.

T

temporary closure

a period of time that a storage tank is empty but is not permanently closed or has not changed service to store a non-regulated substance. This term does not apply when a tank system is emptied for repair.

U

underground storage tank

any one or combination of tanks, including underground pipes connected thereto, except those exempted in statute and these regulations, that is used to contain an accumulation of regulated substances and the volume of which, including the volume of underground pipes connected thereto, is ten percent or more beneath the surface of the ground and is not permanently closed

upgrade

the addition or retrofit of some systems (such as cathodic protection, lining, modification of the system piping, or spill and overfill controls, etc.) to improve the ability of an UST or AST system to prevent the release of product

UST

Any tank system (including all product piping and ancillary equipment) that contains regulated substances that is 10% or greater beneath the ground surface.

USTs

Any tank system (including all product piping and ancillary equipment) that contains regulated substances that is 10% or greater beneath the ground surface.

V

vertical separation

the the minimum thickness of soil between the top of a petroleum vapor source and the bottom of a building foundation to effectively biodegrade hydrocarbons below a level of concern for PVI (ITRC PVI Guidance 3.1.6; EPA PVI Guidance 5)

W

working days

Monday through Friday, excluding state and federal holidays.

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