OSAGE OPERATOR'S ENVIRONMENTAL REFERENCE MANUAL

US Environmental Protection Agency Region 6
Bureau of Indian Affairs,
Osage Nation Minerals Council
Osage Nation Executive Branch
Osage Producers Association

DRAFT
February 2014

List of Acronyms

BIA	Bureau of Indian Affairs
BMP	Best Management Practices
CAA	Clean Air Act
CAED	Compliance Assurance and Enforcement Division
CDL	Compensated Density Log
CFR	Code of Federal Regulations
CNL	Compensated Neutron Log
CWA	Clean Water Act
E&P	Exploration and Production
EPA	Environmental Protection Agency
H2S	Hydrogen Sulfide
HCl	Hydrochloric Acid
IEL	Induction Electric Log
ISIP	Instantaneous Shut in Pressure
MIT	Mechanical Integrity Test
MSDS	Material Safety Data Sheet
MSS	Maintenance Startup Shutdown
NORM	Naturally Occurring Radioactive Material
NPDES	National Pollutant Discharge Elimination System
P&A	Plug and Abandon
PRD	Pressure Relief Devices
PSIG	Pounds Per Square Inch Gauge (excludes atmospheric pressure)
RCRA	Resource Conservation and Recovery Act
REI	Radius of Endangering Influence
SDWA	Safe Drinking Water Act
SPCC	Spill Prevention Control and Countermeasures
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Units
ZEI	Zone of Endangering Influence

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INTRODUCTION

In 1997, Environmental Protection Agency (EPA) and the Bureau of Indian Affairs (BIA) worked with certain parties to develop an Osage Operator's Handbook that provided a clear language interpretation of the regulations and discussed best management practices for oil and gas operations within Osage County to assist with compliance of environmental laws and regulations. The Handbook now needs revisions to incorporate regulatory changes given changes in the law. EPA and BIA plan to revise and update the Handbook in conjunction with the Osage Minerals Council, Nation Representatives, and identified stakeholder groups.

Revision of the Handbook is intended to provide guidance on how to comply with current environmental laws and the regulations governing oil and gas operations within Osage County. The Handbook will also provide clarification on which agencies should be contacted in the event someone has concerns regarding those oil and gas operations. The objective of the Handbook is to provide useful guidance and best management practice standards for daily responsibilities concerning oil and gas operations.

The Handbook is not intended to provide legal advice, replace existing legal obligations with respect to environmental responsibilities or oil and gas operations within Osage County or establish new rules or regulations. The Handbook will not, nor is it intended to, address all aspects of applicable laws and regulations that govern Osage County.

I. IMPORTANT CONTACT INFORMATION

A. Spill Reporting:

1. Report all spills of oil and/or saltwater to the BIA Osage Agency Office at (918) 287-3528 or call the BIA Spill Hotline (918) 287-3107.

2. Report all saltwater spills which enter or threaten to enter a water body to the Environmental Protection Agency,Tulsa Office (918-557-1615).

3. Immediately report an oil spill which enters or threatens to enter a waterway (waters of the United States) to the National Response Center (1-800-424-8802).

B. Well Operations:

1. For Information on

a) How to apply for an underground injection control (UIC) permit,
b) How to complete a UIC permit application,
c) Draft UIC Permits, or
d) To comment on draft UIC permits:

Osage Nation Environmental and Natural Resources Department
100 West Main St. Suite 304
Pawhuska, OK 74056
Phone: 918-287-5333

Groundwater/UIC Section (6WQ-SG)
Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202
Phone: 214-665-7535

e) BIA permits, approvals and/or reports associated with oil and gas leases or oil and gas wells:

BIA Osage Agency Minerals Branch
813 Grandview
Pawhuska, OK 74056
(918) 287-5710

C. For Information on UIC related matters:

1. Compliance with UIC requirements or permit conditions,

2. Regulation or permit requirements,
3. Compliance schedules or enforcement orders,
4. Inspection policies/procedures, or
5. Ongoing investigations:

   Osage Nation Environmental and Natural Resources Department
   Post Office Box 1495
   Pawhuska, OK 74056
   Phone: 918-287-5333

   Environmental Protection Agency
   Region 6
   Water Resources Section (6EN-WR)
   1445 Ross Avenue
   Dallas, TX 75202
   Phone: 214-665-6439

D. For information on BIA regulations and Osage Agency Requirements, contact:

> Osage Agency BIA
> Post Office Box 1539
> Pawhuska, OK 74056
> Phone: 918-287-3528 (Field Operations)

E. For information concerning the EPA regulations for Spill Prevention Control and Countermeasures Program (SPCC) (requirements for berms around tank batteries and plans) contact:

> **Oil Team, Prevention and Response Branch (6SF-PO)**
> **Environmental Protection Agency**
> **1445 Ross Avenue**
> **Dallas, TX 75202**
> **Phone: 214-665-7356**

II. Water Pollution Prevention: The Clean Water Act

The Clean Water Act (CWA) protects surface waters in the United States through implementing regulations, permits, and the law. The Clean Water Act was established to restore and maintain the chemical, physical, and biological integrity of the nation's waters. The CWA aims to protect water quality through development of water quality standards, anti-degradation policies, water quality permitting procedures, water body monitoring and assessment programs, and elimination or point and nonpoint pollution sources. The CWA makes it unlawful to discharge any pollutant from a point source into waters of the United States.

A. Sections of the CWA which regulate oil and gas exploration and production activities include:

1. **Section 301 –** Prohibits the unauthorized discharge of pollutants into waters of the United States. Determining whether a water body meets that definition may be difficult. To avoid a potential violation, oil and gas operators should not discharge to any surface water body.

2. **Section 308** - Provides the EPA with the ability to inspect facilities and to require submission of sampling information.

3. **Section 309 -** Provides the EPA with authority to enforce the CWA including issuing administrative orders, administrative penalties, or initiating civil action for violations of the CWA.

4. **Section 311 - Oil and Hazardous Substances Liability**. Also known as the Spill Prevention, Control and Countermeasure (SPCC) rule, the purpose of this rule is to help facilities prevent a discharge of oil into navigable waters or adjoining shorelines. Refer to the SPCC Section of this Manual for further information and requirements.

III. INJECTION WELL REQUIREMENTS

A. Annual Operation Reports

1. Injection well operators must submit an annual report of injection activities to the Environmental Protection Agency.

2. The EPA sends a notice and suggested report forms(see Form 1) to injection well operators when the report is due. The report due date depends on where the well is located. The following shows report due dates by well location:

Township/Range Location	Report Due Date
Townships 20 North - 23 North, Ranges 6 East - 12 East	January 31
Townships 27 North - 29 North, Ranges 5 East - 12 East	April 30
Townships 24 North - 26 North, Ranges 2 East - 7 East	July 31
Townships 24 North - 26 North, Ranges 8 East - 12 East	October 31

3. Annual reports must include the following:

   a) Average and maximum monthly injection pressures.
   b) Total barrels of fluid injected each month.
   c) Average and maximum annulus pressure (required only if the operator is using annulus monitoring to demonstrate mechanical integrity or the permit requires annulus monitoring).
   d) Information required by the UIC permit for the well. Common requirements are for the operator to report oil and water production from nearby wells,and fluid levels in the injection well or nearby wells.(The operator should review the UIC permit for specific requirements.
   Each permittee must submit this information to the EPA annually. Following the process in Section III.A.2)
   e) Inactive wells may require fluid level monitoring information. A special report form will be provided to include fluid level monitoring information.

4. The operator must keep actual records of monitoring (pumper's log, actual charts, etc.) and a copy of the submitted report for three years after completing the report.

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B. Conversion to Production

1. An operator may convert any injection well to production use at any time. When conversion is complete and the EPA removes the well from its injection well inventory, jurisdiction for the well reverts to the BIA.

2. The well operator must demonstrate that conversion has actually been completed.

a) Obtain conversion permit from the BIA.
b) Complete physical conversion of well (i.e., install rods and tubing, pump jack and motor and begin production).
c) Submit Osage Agency Form No. 139 to both the BIA and the EPA UIC office showing that the conversion is complete.

3. EPA inspects well to verify conversion.

4. If a well is swabbed for production, the operator must (in addition to the items listed above) notify the EPA by letter of the production method and submit a copy of the first lease status report after conversion to verify the amount of oil being produced.

5. If the well is authorized by permit, the permit remains in effect until the permittee requests in writing that the permit be terminated. As long as the permit is in effect, the well can be converted back to injection at any time. Before actual injection takes place, the operator must demonstrate that the well has mechanical integrity.[1]

6. The EPA notifies the well operator before amending its records to show that a well has been converted to production. If the well is being tested for production and may be converted back to injection within a short time (e.g., one month), the operator should notify the EPA upon receipt of the notice of permit termination or loss of authorization by rule.[1]

C. Lease Transfer Procedures

1. All Injection Wells

a) Before purchasing a lease, the purchaser should check with the BIA and EPA to verify that the lease is compliant with BIA and EPA requirements.[3]
b) The purchaser should obtain all pertinent records of well construction and operation from the seller as part of the purchasing agreement.[3]
c) After completing the transfer:

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(1) The purchaser must submit a signed lease assignment (BIA Form F) and a copy of its bond or other form of financial assurance to the BIA.[2]

(2) The seller should submit an operation report to the EPA for the portion of the report period that it operated the well.

d) The assignment form shows the effective date of the transfer. The seller is responsible for all reporting, monitoring, and violations of program requirements until the effective date of the transfer. The buyer is responsible for the lease after the effective date of the transfer.[1,2]

2. If the injection well is authorized by rule, the purchaser should notify the EPA of the lease transfer. The notice may be a copy of the lease assignment and bond sent to the BIA.[3]

3. If the well is authorized bv permit, the seller must notify the EPA of the proposed lease transfer at least ten days before the proposed transfer date. The notice must include a specific date for the transfer and proof that the transferee has financial responsibility for the well. The transfer is effective on the date of the transfer, if the seller submits required documentation and the EPA does not respond with a notice that the permit will be modified[1].

4. The notice of lease transfer may be a copy of the lease assignment and the bond or other form of financial assurance sent to the BIA.

D. Mechanical Integrity Testing

1. All wells must have mechanical integrity before being used for fluid injection.[1]

2. The operator must notify the Osage Nation Environmental and Natural Resources Department at least five days before testing a well so their representative can witness the test.[1] Either a Tribal or EPA inspector must witness all mechanical integrity tests.

3. The two parts of the mechanical integrity demonstration are to prove that:[1]

a) There is no significant fluid movement of fluids through vertical channels behind the well casing

[1]

(1) This is usually determined by reviewing well construction records. Specific construction requirements depend on when the well was drilled.
(2) Table 1 shows construction requirements according to well construction date.
(3) All wells authorized by a permit must comply with the post-1984 construction requirements. The operator can also use a radioactive tracer survey or temperature or noise log to comply with this requirement.

b) There are no significant leaks in the casing, tubing, or packer. Table 2 summarizes the types of tests and requirements to comply with this requirement.

4. The inspector measures the fluid return at the conclusion of each mechanical integrity annulus pressure test.[1] This is used by the test reviewer to estimate packer depth. The amount of fluid return depends on:

a) Annulus fluid type;
b) Tubing and casing materials and size;
c) Time since annulus filled;
d) Injection during the test;
e) Temperature of injected or annular fluids;
f) Packer depth.

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5. If fluid returns indicate shallow packer depth, the EPA Engineer may require proof of packer setting depth before verifying well integrity. Verification may include:

a) Tubing tally;
b) Tubing Log; and
c) Pull tubing from the hole

6. Options for wells that fail a mechanical integrity test.

a) Demonstrate mechanical integrity. Any repair that allows a satisfactory mechanical integrity demonstration is allowed. (NOTE: The use of Angaard or other materials that prevent testing the full length of casing is prohibited).Cease using the well for fluid injection

b) Common repair options include:

(1) Cement squeeze;
(2) Install a concentric packer;
(3) Install a liner;
(4) Repair or Replace the packer;
(5) Cement the casing from the surface to the hole;
(6) Place a casing patch;
(7) Replace the corroded casing joint;
(8) Replace joint of tubing with hole;
(9) Set a liner on a packer (This option requires special monitoring and testing. Operator should call EPA Groundwater/UIC Section for specifics.

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Table 1
Well Construction Requirements

Date Well Drilled	Casing and Cementing Requirements
Pre-April 1953	1. Cemented casing through all underground sources of drinking water OR 2. Cemented casing 100 feet above the injection formation
April 1953 - December 1984	1. Cemented casing through water with less than 3000 mg/1 total dissolved solids. 2. Cemented casing 100 feet above injection formation
After December 1984	1. Cemented casing at least 50 feet below water with less than 10,000 mg/1 total dissolved solids. 2. Cemented casing 100 feet above the injection zone

Table 2
Casing, Tubing, and Packer Mechanical Integrity Test Requirements

Test Options	Procedures	Comments
Casing/Tubing Annulus Pressure Pressure Test	1. Apply pressure of 200 psi to annulus provided that: a) Annulus pressure must be at least 100 psi different from tubing pressure; and/or b) Annulus pressure may be less than 200 psi if required to achieve the 100 psi differential, but can not be less than 100 psi. 2. Observe pressure for 30 minutes. 3. Release pressure and measure fluid returned.	1. Packer fluid must be liquid. 2. Inspector must verify current packer depth with operator. 3. Collect and measure fluid returns at the end of the test. 4. Pass if packer depth is compliant with permit conditions, calculations verify packer depth, and pressure loss after 30 minutes is less than 10%.
"Ada"	1. Measure the static fluid level in the well. 2. Calculate required test	1. Can be used to: a) Test wells with no tubing and packer.

	pressure. 3. Apply gas (usually nitrogen) pressure to force fluid into the perforations. 4. Observe pressure for 30 minutes.	b) Test tubing and packer in wells with perforations or known casing leaks above the packer. c). Determine the depth of the top casing or tubing leak. 2. Pass test if pressure stays within the predicted range for 30 minutes.
Continuous Positive Annulus Pressure (e.g., "Barrel Test")	1. Fill the casing/tubing annulus with liquid and continuously maintain a positive pressure. 2. Observe and record the pressure at least monthly. 3. Report annulus pressure to the EPA on the annual operation report Including monthly volumes of fluid added to or removed from the annulus.	1. Cannot use if the well previously failed an annulus pressure test. 2. Many operators comply by monitoring the fluid level in a barrel connected to the annulus. or 3. Fail test if annulus pressure drops to 0 psig, the operator must frequently add or remove fluid from the annulus to maintain stable pressure, or the operator fails to report monitoring results on its annual report.
Continuous Annulus Fluid Level Monitoring (e.g., "Osage Sentry")	Discuss with EPA Engineer	1. Install a device in the well annulus which would immediately signal when the fluid level rises to the monitor location. 2. May be used for wells with tubing and packer integrity but casing leaks. 3. Must measure annulus fluid level annually. 4. Must demonstrate tubing and packer integrity every five years.
Radioactive Tracer Test	Discuss with EPA Engineer	

7. Alternative mechanical integrity testing procedures.

a) The regulations allow the EPA Regional Administrator to approve alternative mechanical integrity testing procedures applicable to injection wells authorized by rule. EPA Headquarters must approve alternative test procedures for wells authorized by permit.

b) The EPA has approved the mechanical integrity testing procedures shown below for injection wells authorized by rule.

(1) Demonstrate mechanical integrity of the tubing and packer;
(2) Install and maintain a monitoring system approved by EPA which would detect and warn of fluid level in casing/tubing annulus within 100 feet of the base of the lowest underground source of drinking water (USDW);
(3) Measure the static fluid level in the well annulus at least annually;
(4) If the fluid level is detected within 100 feet of the USDW:

   (a) Notify the EPA within 48 hours; and,
   (b) Reset the monitoring device to detect the fluid level within 75 feet of the base of USDWs within five (5) days,.

(5) If the fluid level rises to within 75 feet of the USDW:

   (a) Report to the EPA within 48 hours (The report must include the rate of fluid level rise in feet per day;
   (b) Reset the monitoring device to detect fluid within 50 feet of the base of USDWs within five days

(6) If fluid rises to within 50 feet of the base of USDWs,

   (a) Immediately shut in the well and report to the EPA;
   (b) Submit a corrective action plan to the EPA if the fluid level remains less than 50 feet below the base of USDWs.

E. Permit Procedures and Technical Requirements

1. Overview

a) Injection operations in Osage County, Oklahoma, are primarily for the purpose of enhancing the recovery of oil from the numerous reservoirs that underlay the county. Injection is also used for the disposal of excess produced water into a number of non-productive zones.
b) EPA Region 6 is charged with the direct implementation, in Osage County, of the mandates of the Safe Drinking Water Act (SWDA). A team of engineers in the Ground Water/UIC Section is responsible for preparing the permits required to legally conduct those underground injection operations. The team also reviews the performance of wells that are authorized by rule to inject.

2. Regulatory Requirements

a) Underground injection is allowed only if it is:

(1) Authorized by Rule or,
(2) Permitted under the UIC program.

b) No underground injection may result in the movement of contaminants into a USDW.
c) Details of these rules can be found in Section 2903, Part 147 of Title 40 of the US Code of Federal Regulations (40 CFR §147.2903).

3. Permit Application Package

a) You can obtain an application package from the Osage Nation Enviromental and Natural Resources Department . The following sections provide details justifying the reasons for requesting the information in the package.
b) The permit application package provides the operator an opportunity to educate the permits engineer on the details of an injection project. The operator may post the data on several pre-formatted package documents that make up the application

c) The information is to assist the engineer in characterizing the injection system and in defining the variables that will set the operating conditions in the study area. An assessment of the risk of contamination under these operating conditions over a twenty year period will then be completed.

d) The following documents make up the application package for an Osage UIC permit:

(1) Osage Agency forms 139 and 208;
(2) The Well Schematic Form;
(3) The Well Operation and Geologic Data Form;
(4) The Well Tabulation;
(5) Map(s).

4. Permit Issuance Process

a) Emergency Permit

(1) The UIC regulations make provisions for the issuance of emergency permits.

(2) Section 2906, Part 147 of Title 40 of the US Code of Federal Regulations
(40 CFR§147.2906) discusses the circumstances under which EPA may issue an emergency permit.

b) Engineering Review Process

(1) Determining injection rate

(a) The main objective of the engineering review process is to determine the rate of accumulation that is environmentally safe and to formulate operating conditions that will contribute to minimize the risk contamination risk to USDWs.

(b) The rate of accumulation (or "net" injection rate) relates to the volume of injected fluids that over a number of days fails to reach the producing wells in an enhanced oil recovery project.

(c) In this type of project the "net" injection rate for a well, or group of wells, may be lower than the injection rate measured at the wellhead (the "gross" injection rate). In disposal operations, on the other hand, all of the injected fluids remain in the reservoir.

(d) The pressure build up effected in the reservoir by the accumulation of injected fluids must not result in the movement of fluids into a USDW.

(e) For a given period of operation, the estimated rate of accumulation of injected fluids is a function of a number of variables. Some of these variables are the result of decisions made by the operators and some are intrinsic to the reservoir.

(f) The following discussion on the stages of the engineering evaluation identifies several of those variables.

(2) Understanding the Reservoir Flow System on Hand

(a) The analysis of a reservoir flow system usually starts by reviewing maps for the area of interest. In the Osage UIC program, the type of map most frequently available to the engineer is the location (plat) map.

(b) The location map provides, at a minimum, visual information on the well population and distribution. These two important factors have great potential for impacting the reservoir flow pattern and, by default, the allowable rate of accumulation for a given period of operation.

(c) The information on the provided map is usually complemented with other information from the application package to establish the number of improperly completed and improperly plugged and abandoned (P&A'd) wells. It is equally important that the map identify the type of each remaining well in the area under study.

(d) It is very likely that the larger the number of injection wells in a given reservoir, the lower the environmentally safe rate of accumulation for each well if all other variables remain the same.

(3) Identifying Points with Endangerment Potential

(a) Points with potential for endangerment within a study area are those locations where injected fluids could migrate from the injection zone into USDWs.

(b) The most frequently found avenues for the vertical movement of injected fluids into USDWs are improperly completed or plugged wells. Appendix B illustrates, with well schematics, the requirements for proper plugging and abandoning wells.

(i) Improperly Completed Well - A well is considered improperly completed if:

(a) Surface casing cement not circulated;
(b) Surface casing cemented but not set at least 50 feet below the base of USDWs;
(c) Production casing not cemented;
(d) Top of production casing cement less than 100 feet above the top of the injection interval; or,
(e) Uncemented casing opposite injection zones in neighboring wells.

(ii) Improperly Plugged and Abandoned (P&A'd) Well – A well is considered to be improperly plugged and abandoned if:

(a) Open hole filled only with mud and debris;
(b) Production casing ripped above the top of cement, pulled, and the hole is filled with mud;
(c) Cement plugs placed inside uncemented suface or production casing;
(d) Cement plugs improperly located or sized; or
(e) No information is provided on the plugging procedure.

(4) Estimating the Base of USDWs

(a) The permitted rate of accumulation for two wells with identical completion and reservoir characteristics would differ if the depth to the base of the USDWs were different. The well with a deeper USDW depth would be permitted at a lower rate of accumulation.

(b) Following are two approaches that may be used to determine the USDW.

(i) Fresh Water Supply Well Inventory - The reviewer may search a database of information on the ownership, location and completion of private fresh water supply wells in Osage County, Oklahoma. The information in this database can provide insight into the depth of fresh water sands in a study area. Though it is not certain that the depth information may correspond to the base of the USDWs, it may prove valuable in assessing endangerment risk in the absence of any other data.

(ii) An Approximate Empirical Approach - Ideally, an electric log run through the fresh water sands will be available for the well of interest. If such log is not available, the reviewer may use a log from the proposed injection well (preferred) or a neighboring well to estimate the depth of the base of USDWs.

(5) Estimating the Reservoir Pressure

(a) The estimated rate of accumulation will be lower for the well with the larger reservoir pressure, if remaining parameters are identical. The permits team usually performs estimates of the reservoir pressure using field data.

(b) The following illustrates some of the sources for these data.

(i) Fluid Level Data – A fluid level measurement is used to estimate the reservoir pressure at that location. Field staff measure the fluid level in a well using an echometer after the well has been shut in long enough to approach static conditions. If the fluid level is obtained before the well has stabilized, the reservoir pressure and rate of accumulation estimates will be in error.

(ii) Well Transient Test Data - The reservoir pressure can be estimated from well test data such as that gathered through fall off, build up or drill stem tests. This information can also be used to estimate the reservoir permeability.

(6) Estimating Formation Absolute Permeability, Porosity and Effective Thickness

(a) Permeability, porosity and thickness are reservoir intrinsic properties that greatly affect the amount of produced water which can be injected into the formation.

(b) The more permeable a rock, the greater its ability to accumulate fluids for a given limiting pressure increment and over a given period of operation. An injection zone in a production area may be expected to be more permeable if it is more porous.

(c) The reservoir effective thickness is primarily a function of the rock's permeability and of the perforated interval. If a well has been cased and cemented, the effective thickness may be changed when perforations are added or squeezed.

(d) The following discussion illustrates the sources of information the Osage UIC engineers explore to obtain the needed permeability, porosity and thickness information.

(i) Laboratory Core Analysis Reports - Core analysis reports usually provide information on permeability determined for core plugs that have been fully saturated with fluid. The reported values are generally regarded as the absolute permeability for the sampled interval, usually one foot thick.

(ii) Well Transient Test Information - It is common practice in reservoir evaluation to use some widely approved engineering methods to estimate permeability using information (pressure, fluid flow, elapsed time, etc.) gathered by conducting well transient tests. The permeability estimated by these means may have been a function of the saturation of a given fluid in the reservoir at the time of the test (i.e., relative permeability).

(7) Estimating the Water Viscosity

(a) Water viscosity is generally assumed to be one centipoise.

(b) Viscosity changes with reservoir characteristics.

(c) Water viscosity can be estimated as a function of temperature and pressure using empirical correlations.

(d) Information on the water salinity (ppm Total Dissolved Salts (TDS)) will also be needed.

(8) Estimating the Zone Of Endangering Influence (ZEI)

(a) After the permits engineer has gathered and validated information for all necessary variables, an analysis of the reservoir pressure response is prepared. The pressure response of interest is affected by the accumulation of fluids in the injection zone during a predefined period of operation.

(b) The Osage UIC program estimates pressures generated by the injection activity at certain distances from the injection point(s) using simple algebraic expressions. One expression applies to liquid injection operations and another to gas injection operations. These equations are greatly simplified solutions to a more complicated mathematical expression which has already been simplified thanks to a number of assumptions including that the reservoir is 100% saturated with the injected fluid and it is infinite acting at all times. As a result, the answers obtained are approximations.

(c) Identifying the Radial Distance to the Point of Potential Endangerment.

(i) Of special interest to the engineering review are the distances between an identified point with potential for endangerment (e.g., an improperly completed, or unplugged well penetrating the injection formation) and one or more injection wells in the area. These interwell distances are permanently defined when an operator drills a well, fixing in this way the field's well pattern.

(ii) One of these distances may be found to be the radius of endangering influence (REI) for the permit well or the field under study.

(iii) Computing the Critical Rate of Accumulation - In the Osage UIC program, the critical rate of accumulation is the injection rate (barrels per day) that, after 20 years of injection, would increase pressure at the nearest improperly completed or unplugged well to the extent that fluids would flow through the well into USDWs.

(iv) Compliance with certain safety constraints may warrant departures from this basic concept.

(a) Single Injection Well Systems - For a single injection well system, the critical rate of accumulation or environmentally safe rate of accumulation is computed using the distance to an identified point with potential for endangerment as the value for the radius required as input. Smaller radial distances will result in smaller allowed rates of accumulation.

(b) Multiple Injection Well Systems - Whenever continuity of the injection zone throughout the study area has been established, it will be necessary to estimate the combined pressure effect of several injection wells at points with potential for endangerment. Under this flow scenario, a multiple injection well system results.

(9) Estimating the Maximum Allowable Injection Pressure

(a) Maximum injection pressures are designed to minimize the risk of contamination of USDWs by preventing unintentional fracture propagation through confining formations adjacent to USDWs. This parameter may be need revisions during the life of a project to optimize injection operations.

(b) In the Osage UIC program uses either an assumed formation fracturing pressure gradient, or instantaneous shut in pressure (ISIP) recorded during a well stimulation job to establish maximum injection pressure.

(c) The following describes how to estimate maximum injection pressure using historical well data.

(i) Instantaneous shut in pressures (ISIPs) are representative of the pressure that would cause a fracture to reopen. These pressure readings may be available from the operator's files, especially in areas with aggressive well stimulation programs.
(ii) Step Rate Test - It may be necessary to modify the permitted maximum injection pressure based on updated information because formation fracture pressure may change with time. One approach for updating this information is to run a step rate test. The permits engineer may design and request a step rate test to estimate the new maximum allowed injection pressure from the rate and pressure data gathered.

c) The Administrative Process

(1) The objective of the administrative process is to document and communicate the permit engineer's conclusions and recommendations for review, approval, and release to the permittee and the public. The following discusses important documents that make up a permit package.
(2) Components of an EPA Osage UIC Permit

(a) All permits include the following conditions:

(i) Construction Requirements

(a) Casing and Cement
(b) Wellhead Fittings
(c) Tubing and Packer
(d) Plugging Requirements

(ii) Operating Requirements
(a) Mechanical Integrity
(b) Maximum Wellhead Injection pressure
(c) Injected Fluid Type and Purpose
(d) Net Injection Rate
(e) Fluid Level Monitoring

(iii) Reporting Requirements

(b) Some permits include additional conditions based on the permit engineer's analysis of information which the operator provided. A summary of some of those conditions and the type of information associated with their development follows:

(i) Well Completion and Plugging:

- Cement Bond Log
- Cement Tickets
- Caliper Log
- Sacks of Cement
- Cement Additives (Type and Quantity)

(ii) Conditions Related to Well Operation

Maximum Injection Wellhead Pressure
Step Rate Test
Formation Fracturing Pressure

- Gradient
- Water Analysis (Specific Gravity)

(iii) Rate of Accumulation

- Historical Injection Rates and Pressures
- Water Analysis (Viscosity)
- Well Logs (IEL, CDL/CNL)
- Core Analysis Reports
- Static Fluid Level Data
- Well Transient Tests

(3) Conditions Applicable to All Permits

(a) The Osage UIC permit includes conditions applicable to all permits. Of special interest within this section is the condition on reporting.

(b) An annual operation report is required for all injection wells. Details on the report submittal schedule are in the Annual Operation Report section of this manual, and a sample form is attached as Form 1.

(c) The requested information on injection rates, pressures and production rates is to periodically analyze reservoir performance relating to potential endangerment of USDWs.

(d) The following table illustrates one way of jointly reporting the monthly rates for the injection and production streams:

Injection Parameters				Production Parameters	
Month / Year	Avg PSIG	Max PSIG	BBL / Mo.	Oil BPM	Water BPM

(e) Fluid level monitoring information can be reported in a similar format.

(4) Document Preparation and Submittal

(a) Figure 1 is a flowchart to assist in visualizing the document preparation and submittal process.
(b) Draft Permit, Statement of Basis and Newspaper Notice
(i) The permits engineer prepares a draft permit package consisting of a transmittal letter, a draft permit, a statement of basis, and a summary of information to appear in a newspaper notice.
(ii) The Source Water Protection Branch Associate Director approves the draft permit package by signing the transmittal letter.
(iii) A newspaper of general circulation in the well permit area publishes notice of the draft permit.
(iv) The permittee and the public have fifteen (15) days following publication of the newspaper notice to offer comments on the draft permit.

(5) The Final Permit

(a) –If neither the public nor the permit applicant submit written comments

(i) The Water Quality Protection Division Director issues the permit, and
(ii) The pemit becomes effective on the date issued.

(b) If either the public or the permit applicant comment on the draft permit,

(i) The permit engineer prepares a response to comments and appropriate revisions to the draft permit, if any.
(ii) The Water Quality Protection Division Director signs the permit and a transmittal letter,
(iii) The EPA sends a copy of the final pemit to the permit applicant and anybody who commented on the draft permit.
(iv) The permit becomes effective 30 days after Division Director approval.

(6) Authorization to Inject

(a) Final permits require the permittee to obtain authorization to inject before using the well for injection. The permittee must comply with listed conditions (most notably completing required construction and passing a mechanical integrity test (MIT)) before receiving such authorization. The

(b) Chief of the Groundwater/UIC Section may give verbal authorization to inject. The Water Quality Protection Division Director later issues a written authorization to inject.

(c) Osage UIC program regulations require injection well operators to complete a MITs at least every five years.

(d) The Regional Administrator can require a different testing frequency on a case-by-case basis (40 CFR §§147.2920(b)(1)(v) and 147.2920(b)(2)(v)). This allows the prescription of testing frequencies that reflect the risk of mechanical failure in wells, especially in the case of less conventional completions. For example, the MIT frequency for wells without cemented surface casing through USDWs is usually three years.

(7) Program Contacts

(a) The Osage UIC program at EPA Region 6 falls under the responsibility of the Ground Water/UIC Section which in turn forms part of the Source Water Protection Branch. This Branch is part of the Water Quality Protection Division.

(b) Following are the officials who have jurisdiction over permitting matters concerning the Osage UIC program in Region 6:

Director, Water Quality, Protection Division 214-665-7101

Chief, Source Water, Protection Branch 214-665-7150

Chief, Groundwater/UIC Section 214-665-8324

Chief, Administrative, Support Office 214-665-7191

5. Permit Modifications

a) Operator Requested Modifications - An operator can submit a written request for a permit modification whenever a reasonable cause exists. The circumstances under which an operator may obtain a permit modification are provided in 40 CFR §147.2927.

b) Interested Party Requested - Any interested party may submit to the

Regional Administrator a written request for the modification of an Osage UIC permit. The Regional Administrator may grant the request if reasonable cause for modification exists (40 CFR §147.2927 (a)(5)).

c) EPA Initiated Modifications - The Regional Administrator may modify any permit If it receives information during the course of a permit review or inspection that warrants a permit modification (40 CFR §147.2927(a)(2)).

6. Plugging and Abandonment

a) The operator must plug its injection wells within one year after ceasing injection operations.

b) EPA may extend plugging deadline for injection wells if there is a viable plan for future use and no fluid movement into an underground source of drinking water would occur.

c) Application to Plug

(1) Submit BIA form No. 139 to the Bureau of Indian Affairs (Osage Agency) and, if plugging an injection well, to the Osage Nation Environmental and Natural Resources Department at least five days before planning to plug a well.
(2) Include outline of plugging procedures or request plugging instructions from the appropriate agency.
(3) Include a $15.00 filing fee with the plugging plan submitted to the BIA.
(4) Table 3 and Figures 2 through 8 summarize plugging requirements for several types of well construction.

d) After you receive notification from EPA that your plugging plan is approved, you must contact the EPA at 918-605-1643 at least five days before initiating plugging so they can witness plugging procedures.

e) After completing plugging:

(1) Cut off the casings and restore the surface location, including removing all junk from the location;
(2) Submit an BIA form No. 139 which includes a summary of actual plugging procedures and copies of cement tickets to the BIA and, if the well is an injection well, to the Osage Nation Environmental and Natural Resources Department, and
(3) Request an inspection from the BIA and, if the well is an injection well, the Osage Nation Environmental and Natural Resources Department.

NOTE: ONLY THE BIA MUST BE NOTIFIED IF PLUGGING A PRODUCTION WELL.

Table 3
Plugging Requirements

Current Well Construction	Pulled Casings	Plugging Procedure
Surface casing set and cemented at least 50 feet below all USDWs or production casing cemented to surface, AND Production casing cemented above production formation. See Figures 2, 6 and 7	Production casing pulled 50 feet below the base of USDWs	a. Set plug through injection formation to 50 feet above formation. b. Pull production casing from at least 50 feet below base of USDWs. c. Set plug from 50 feet below to 50 feet above surface casing shoe. d. Set plug from 20 to 3 feet subsurface. e. Cut off the casing 3 feet subsurface, weld on a cap and restore location.
	Production casing NOT pulled 50 feet below the base of USDWs	a. Set plug through injection formation to 50 feet above formation. b. Part or perforate production casing at least 50 feet below base of USDWs and circulate cement to surface. (Not applicable if production casing is cemented to surface) c. Set plug from 50 feet below to 50 feet above the base of USDWs. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.
Surface casing not cemented through all USDWs; AND Production casing cemented above injection formation See Figures 3, 4, 6 and 7	Production casing pulled at least 50 feet below base of USDWs	a. Set plug through injection formation to 50 feet above formation. b. Pull production casing at least 50 feet below base of USDWs. c. Set plug from 50 feet below base of USDWs to 50 feet above surface casing shoe. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.
	Production Casing not pulled	a. Set plug through injection formation to 50 feet above formation. b. Perforate or part production casing at least 50 feet below base of USDWs and circulate cement behind casing. c. Set plug from 50 feet below to 50 feet above the base of USDWs. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.

Figure 1
Administrative Procedure for Osage Class II Permit
and Permit Modification Issuance

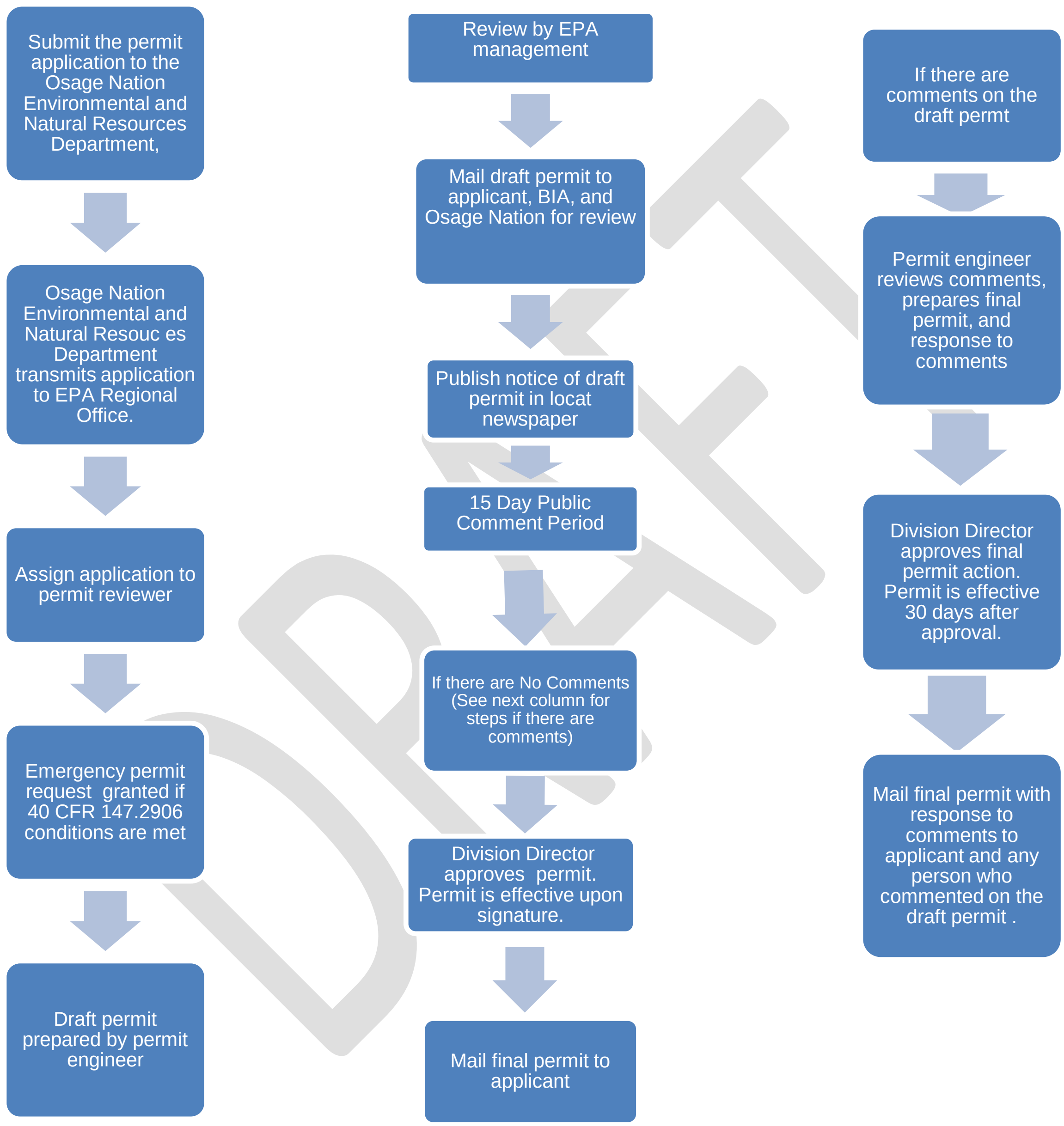


Figure 2
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Surface casing Plugs (40 CFR 147.2905.(e).(1) and
(40 CFR 147.2905.(e).(3)

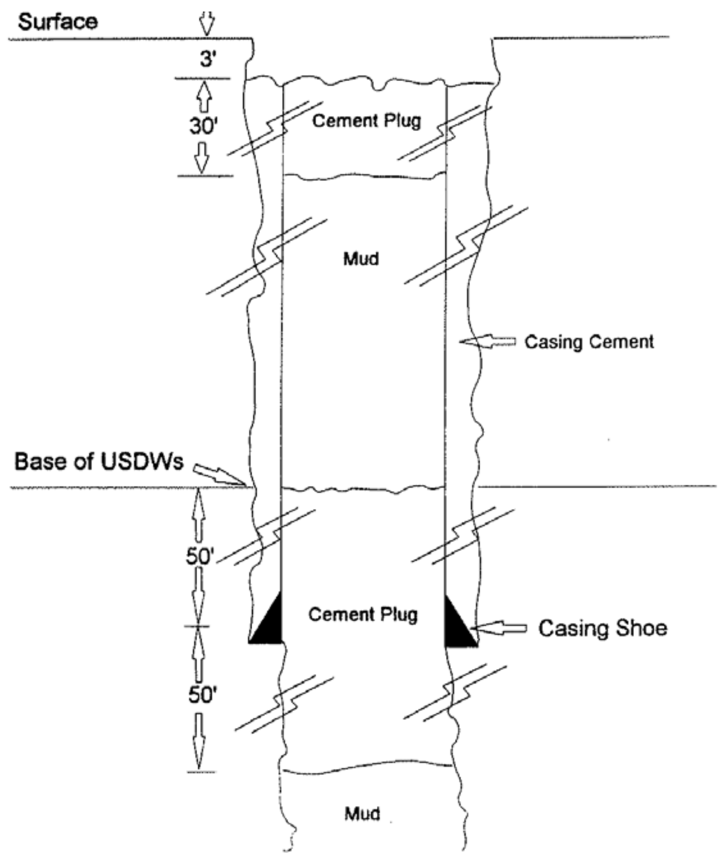


Figure 3
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Surface casing Plugs (40 CFR 147.2905.(e).(1) and
(40 CFR 147.2905.(e).(3)

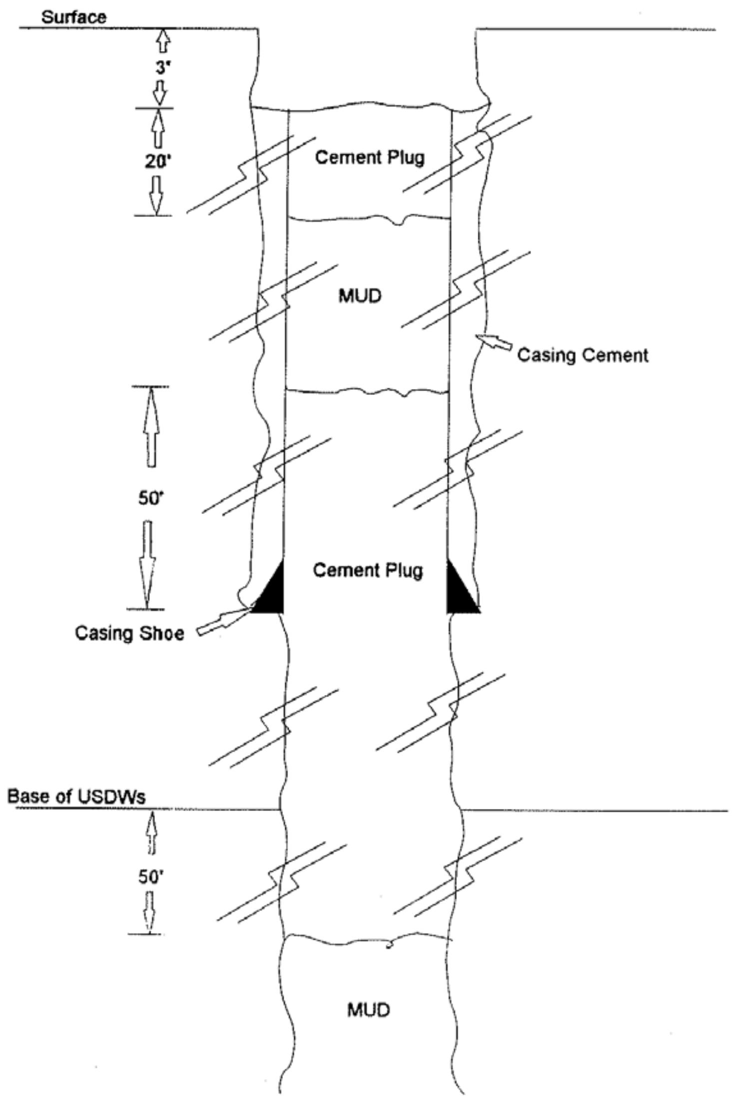


Figure 4
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
For Open Hole Section (Below Production Casing Shoe) (40 CFR 147.2905.(g))

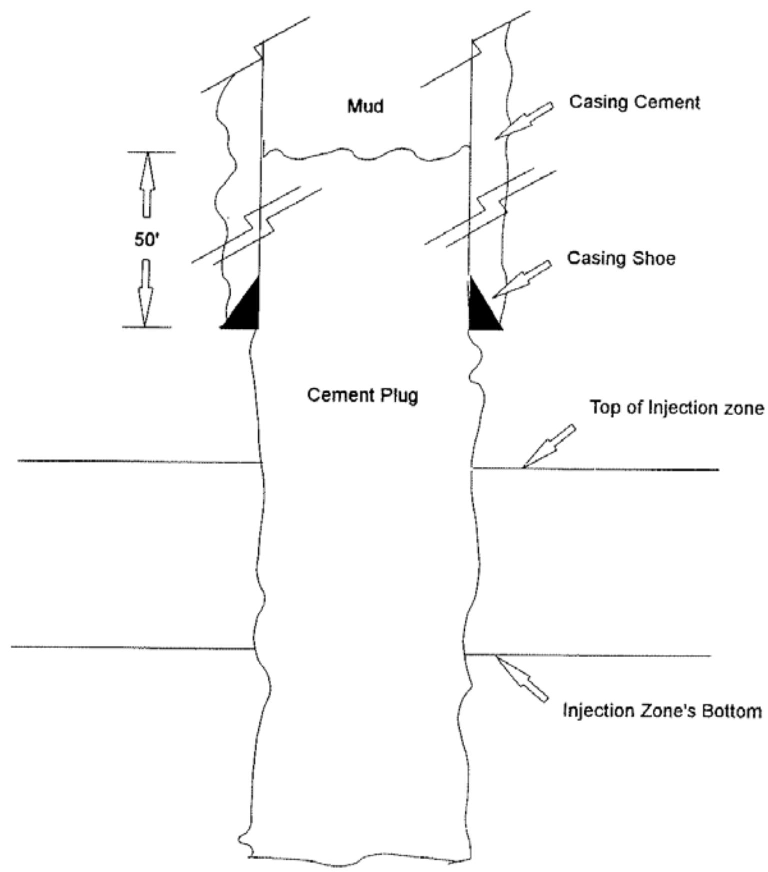


Figure 5
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Plugs For Hole Section With Liner or Screen (40 CFR 147.2905.(g))

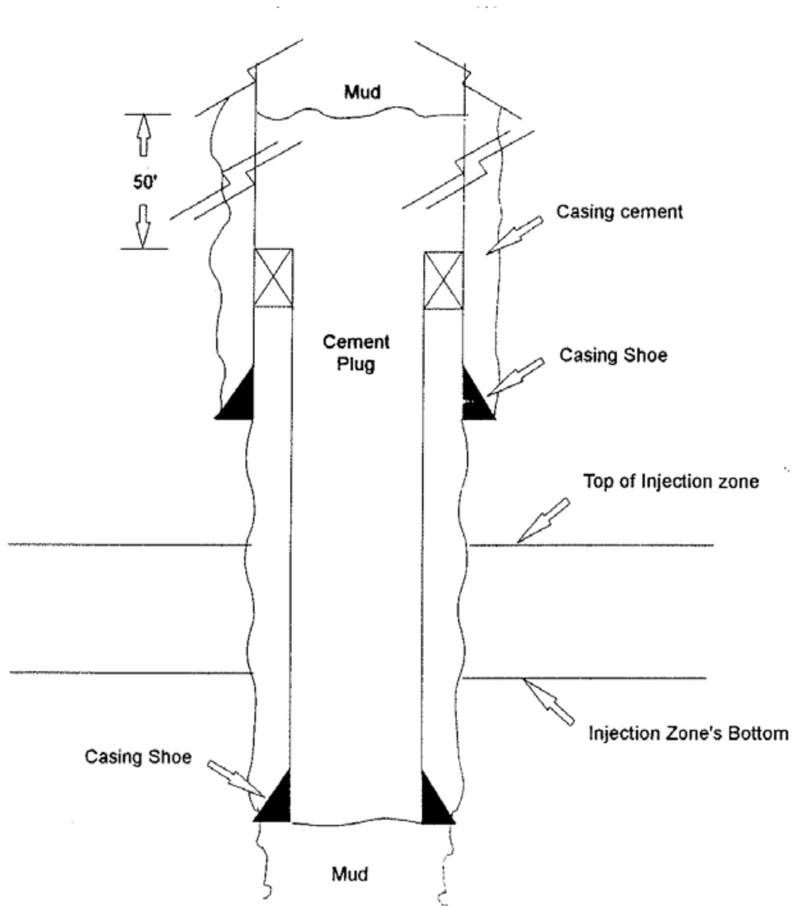


Figure 6
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Plug For Open Hole Section Below Production Casing Shoe
(40 CFR 147.2905.(g)

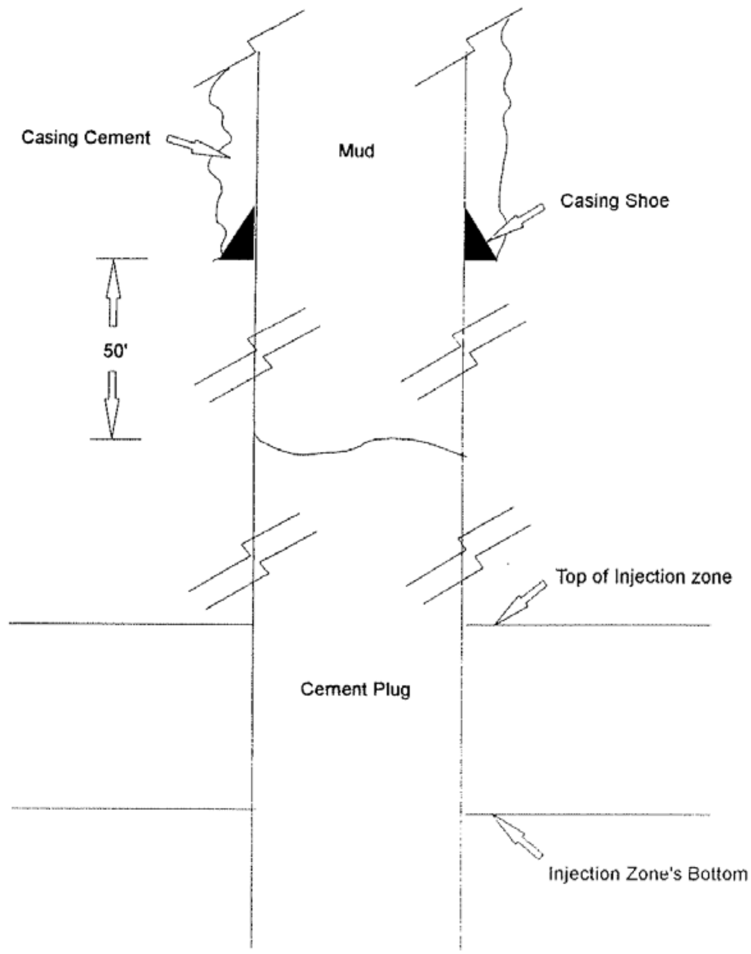


Figure 7
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Plugs For Ripped Production casing (Cemented)
(40 CFR 147.2905.(f).(2)

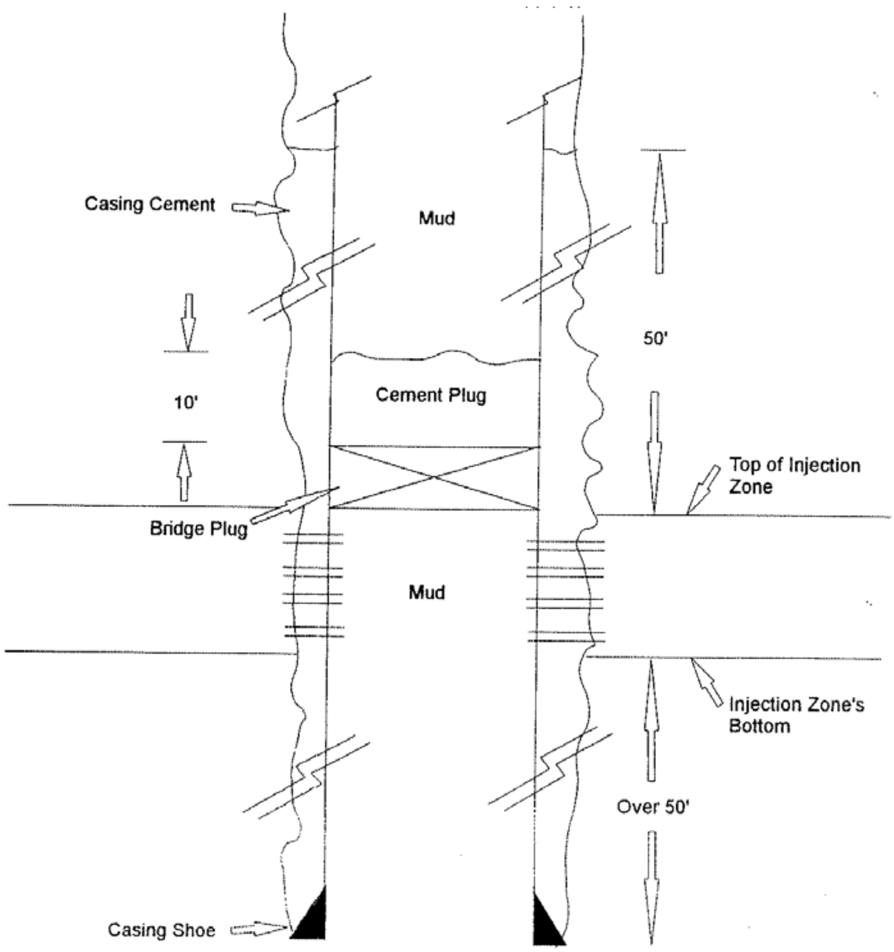
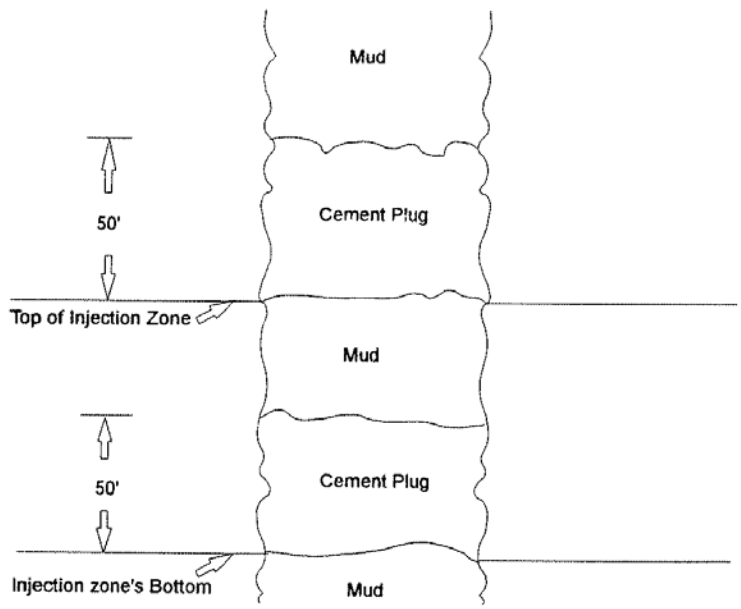


Figure 8
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Open Hole Section Plugs (40 CFR 147.2905.(f).(1)



IV. SPILL PREVENTION CONTROL AND COUNTERMEASURES

A. Brief Overview of SPCC Regulations 40 CFR 112

1. Definitions

a) Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary nontransportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate), or associated storage or measurement, and is located in an oil or gas field, at a facility.

b) Discharge includes but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil.

2. Overview - SPCC regulations apply to facilities that:

a) Have total above-ground storage capacity of 1,320 gallons (31 barrels). Only containers with a capacity of 55 U.S. gallons or greater are counted.; or
b) Have a total underground buried storage capacity of greater than 42,000 gallons of oil; and,
c) Could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, due to their location.

3. Requirements for Preparation and Implementation of SPCC Plans for Onshore production facilities that began production:

a) On or before August 16, 2002 must

(1) Maintain its existing SPCC Plan
(2) Amend and implement the amended SPCC Plan no later than November 10, 2011

b) After August 16, 2002 - Prepare and implement an SPCC Plan no later than November 10, 2011
c) After November 10, 2011 - Prepare and implement an SPCC Plan within six months after beginning operations

4. Guidelines for Implementation of SPCC Plans

a) Close and seal dike drain valves at all times, except when draining uncontaminated rainwater
b) inspect the retained rainwater to ensure that its presence will not cause a

discharge as described in § 112.1(b)prior to drainage;

c) Remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods. Open the bypass valve and reseal it following drainage under responsible supervision and keep records of all drainage events.

d) Construct all tank battery, separation, and treating facility installations, so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation.

5. Prepare and implement a flowline maintenance program. The maintenance program must ensure that flowlines and gathering lines are compatible with the type of production fluids, their corrosivity, volume, and pressure, and other conditions expected;

a) Visually inspect and/or test flowlines and gathering lines and associated equipment on a regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge.

b) the frequency and type of testing must allow for the implementation of a contingency plan as described in the attachment for flowlines and gathering lines that are not provided with secondary containment; and

c) Take action and make repairs to any flowlines and gathering lines and associated equipment as identified by inspections, tests, or evidence of a discharge;

d) Promptly remove or/and clean up any oil discharges associated with flowlines, gathering lines, and associated equipment.

6. Availability, Review, Updates and Certification

a) Onshore production facilities must maintain a complete copy of the Plan at the facility, if the facility is normally attended at least four hours per day, or at the nearest field office if the facility is not so attended, and have the Plan available for on-site review during normal working hours.

b) A Registered Professional Engineer must review and certify each SPCC Plan .

c) The owner or operator is required to amend the Plan for the following reasons:

(1) When required by the EPA after review of the Plan,

(2) Whenever there is a change in facility design, construction, operations, or maintenance which materially affects the potential for an oil spill; or

d) The owner or operator is required to review each SPCC Plan every 5 years and the SPCC Plan must be amended within 6 months of review, if applicable.

7. Reporting Requirements

The operator must submit the information below to EPA and to the appropriate Tribal agency whenever a facility has:

(1) Discharged more than 1,000 U.S. gallons (approximately 24 barrels) of oil into navigable waters in a single spill event; or
(2) Discharged more than 42 U.S. gallons (one barrel) of oil into navigable waters in two reportable spill events within any 12-month period.
(3) The operator must submit the following to the EPA Regional Administrator within 60 days of the occurrence of either of the above two conditions:
(a) (Mail to: USEPA Region 6, ATTN: SPCC Coordinator (6SF-PO), 1445 Ross Avenue, Dallas, Texas 75202-2 733)
(i) Name of facility;
(ii) Your name;
(iii) Location of facility;
(iv) Maximum storage capacity of the facility and current normal throughput;
(v) Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;
(vi) An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;
(vii) The cause of the discharge as described in § 112.1(b);
(viii) Additional preventive measures taken to prevent this from happening again; and
(ix) Any other information the EPA Region requests.

8. Training

a) Train your oil-handling personnel in the operation and maintenance of equipment; discharge procedures; applicable rules and regulations; general facility operations; and the SPCC Plan.
b) Designate a person at each facility who is accountable for SPCC and who reports to facility management.
c) Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan. Briefings must cover spills, failures, malfunctioning components.

9. Inspections, tests, and records: Conduct inspections and tests of the facility, in accordance with written procedures developed for the facility. You must keep these records, signed by the appropriate supervisor, with the SPCC Plan for a period of three years.

10. Civil Penalties - Owners and operators of facilities who violate the requirements of the regulations relating to preparation, implementation, and amendments to SPCC Plans are liable for a civil penalty of not more than $25,000 for each day such violation continues.

11. *This guidance document is a brief summary of the SPCC Regulations and provides production facilities with information that is valuable for the developing and implementating their SPCC Plan. This guidance does not address all aspects of the SPCC rule or options available for compliance, nor is it a substitute for the regulation itself.

You may find more information at:
http://www.epa.gov/oem/content/spcc/index.htm
SPCC Plan format is found in Appendix XX of this document

Who should I contact for more information:

U.S. EPA Region 6
1445 Ross Ave. (6SF-RO)
Dallas, TX 75202-2733
214-665-6444

V. CLEAN AIR ACT

A. Clean Air Act Roles and Responsibilities - The Clean Air Act is a federal law covering the entire country. However, states, tribes and local governments do a lot of the work to meet the Act's requirements. For example, representatives from these agencies work with companies to reduce air pollution. They also review and approve permit applications for industries or chemical processes.

1. EPA's Role - Under the Clean Air Act, EPA sets limits on certain air pollutants, including setting limits on how much can be in the air anywhere in the United States. This helps ensure basic health and environmental protection from air pollution for all Americans. The Clean Air Act also gives EPA the authority to limit emissions of air pollutants coming from sources like chemical plants, utilities, and steel mills. Individual states or tribes may have stronger air pollution laws, but they may not have weaker pollution limits than those set by EPA. EPA must approve state, tribal, and local agency plans for reducing air pollution.

2. Tribal Nations' Role

a) In its 1990 revision of the Clean Air Act, Congress recognized that Indian Tribes have the authority to implement air pollution control programs.

b) EPA's Tribal Authority Rule gives Tribes the ability to develop air quality management programs, write rules to reduce air pollution and implement and enforce their rules in Indian Country. While state and local agencies are responsible for all Clean Air Act requirements, Tribes may choose to develop and implement only those parts of the Clean Air Act that they deem to be appropriate.

c) Best Management Practices (BMP's) - The Osage Nation has an Environment and Natural Resources Department with staff who may obtain EPA-approved inspectors credentials for specific environmental programs. The Department conducts environmental monitoring, sampling and other activities, and coordinates with EPA and other federal agencies on matters of common interest.

B. These best management practices) are designed to prevent or reduce impacts on ambient air from oil and gas operations.

1. Well Site - A new well site or an existing well site could require one or more air permits after all emission sources and points are calculated. All emission estimation methods used for permitting should also be used in a way that is consistent with protocols established in federal regulations. All permit conditions should be strictly adhered to.

2. All facilities which have the potential to emit air contaminants should be maintained in good working order and operated properly during facility operations. Each operator should establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program should include:

a) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices which includes the cleaning and routine inspection of all equipment; and

b) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices which includes the cleaning and routine inspection of all equipment; and

c) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance; and

d) "Green Completion" practices and procedures to reduce methane emissions, air toxics, flaring events, and noise levels; and

e) Conduct daily audio, visual and olfactory inspections recorded in a log book.

C. Fugitive Emissions

1. The following should apply to all fugitive components associated with the well site:

a) Install, check, and properly maintain all seals and gaskets in volatile organic compounds (VOC) or H2S service to prevent leaking. Physically inspect all components weekly for leaks, and may be subject to a leak detection and repair (LDAR) program.

b) Repair all components found to be leaking. Make every reasonable effort to repair a leaking component. Immediately tag or note in a log all leaks not repaired. Repair leaks as quickly as possible at manned and unmanned sites,.

c) Close (but do not completely seal to maintain safe design functionality) tank hatches, not designed to be completely sealed, except for sampling, gauging, loading, unloading, or planned maintenance activities.

d) Locate new and reworked valves and piping connections in a place that is reasonably accessible for leak checking to the extent that good engineering practices will permit.

e) Capture all non-combustion VOC emissions and direct them to an appropriate control device with a minimum design control efficiency of at least 95%.

- **f)** Use optical leak imaging using a hand-held infrared camera to quickly locate leaking components for rapid repair or replacement.
- **g)** Use dust control measures (spraying of water) to control dust, if necessary. Water used for dust abatement should not contain oil or solvents. Do not use dust abatement as a means of water disposal.
- **h)** Install and properly use vapor recovery units (VRU) to reduce methane emissions.
- **i)** Convert gas pneumatic controls to instrument air to eliminate methane emissions.

D. Flares

1. Flares used for control of emissions from production, planned Maintenance Startup Shutdown (MSS), emergency, or upset events should maintain a destruction efficiency of 98% for VOCs and H2S, and 99% for VOCs. All flares should adhere to manufacturers' operation and maintenance requirements to minimize emissions in accordance with the following.

- **a)** Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;
- **b)** If necessary to ensure adequate combustion, add sufficient gas to make the gases combustible;
- **c)** An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;
- **d)** Use an automatic ignition system in lieu of a continuous pilot;
- **e)** Light flares at all times when gas streams are present;
- **f)** Use sweet gas or liquid petroleum gas fuel for all flares except where only field gas is available and it is not sweetened at the site;
- **g)** Design and operate flares with no visible emissions, except for periods not to exceed at total of 5 minutes during any two consecutive hours.
- **h)** Flares may be designed with steam or air assist to help reduce visible emissions from the flare but should meet the appropriate requirements in 40 CFR 60.18.
- **i)** At no time should minimum heating values fall below the associated minimum heating value in 40 CFR §60.18, and
- **j)** Collect and compress vented or flared gas and then sell it as a product.

E. Tanks

1. Do not allow open-topped tanks or ponds containing VOCs or H2S.

- **a)** Close tank hatches and valves, which emit to the atmosphere, except for sampling or planned maintenance activities. Design and operate all pressure relief devices (PRD) to ensure that proper pressure in the vessel is maintained. They should stay closed except in upset or malfunction conditions. If the PRD does not automatically reset, reset it as quickly as possible at a manned or unmanned site.

b) Equip all storage tanks with a storage capacity greater than 500 gallons with a submerged fill.

2. It is recommended that loading be performed with submerged filling, or vapor balancing back to the tank and any subsequent recovery or control device.

a) Do not allow splash loading and uncontrolled vacuum truck loading. Perform loading with a control effectiveness of at least 42% as compared to splash loading. Loading may occur by submerged filling or equivalent prevention or recovery technique.

b) Capture loading vapors and direct them to an appropriate control device with a minimum design control efficiency of at least 98%, routed to a vapor recovery unit (VRU) with a control effectiveness of at least 95%, or vapor balanced back to the delivering storage tank equipped with a VRU, or connected to a control device with a minimum design control efficiency of at least 95%.

c) Where loading control is required, connect the collection or capture system to the tank truck so all displaced vapors are directed to the control device and the control device is operational before loading begins. When properly connected the capture efficiency should be assumed to be 70% efficient at capturing the displaced truck vapors. The capture efficiency may be assumed to be efficient when the tanker truck has certification that the tank has passed vapor-tightness testing. Discontinue loading when liquid or gas leaks from the loading or collection system are observed.

F. Hydrogen Sulfide

H2S is a flammable, odorless gas with an odor characteristic of rotten eggs. Hydrogen sulfide (H2S) may occur naturally in crude petroleum and natural gas production. It is not present in all cases but where drilling operations may penetrate certain zones. The human olfactory system can sense H2S at very low levels of less than 0.1 ppm. The IDLH for H2S is 300 ppm. IDLH is an acronym for Immediately Dangerous to Life or Health, and is defined by the US National Institute for Occupational Safety and Health (NIOSH) as exposure to airborne contaminants that is "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment."

1. During drilling operations, where H2S is reasonably expected to be present, maintain and implement a vigorous safety plan to include hydrogen sulfide (H2S) monitors onsite with alarms and sirens, and the mandatory wearing of individual H2S monitors for personal safety and protection. H2S should not be released into the environment.

2. Hydrogen sulfide is not designated as a hazardous air pollutant so EPA does not have specific criteria for its control. However, H2S is a component of the fugitive emissions that may be released from oil production facilities. EPA generally controls H2S through implementation of BMPs designed to control fugitive emissions.
3. When production facilities where H2S gas is present are located in populated areas they should be equipped with appropriate warning devices.

Additional best management practices can be found at the U.S. EPA Energy Gas Star Website:

http://www.epa.gov/gasstar/tools/recommended.html

VI. RESOURCE CONSERVATION AND RECOVERY ACT

A. Exploration and Production Waste Exemption - The Resources Conservation and Recovery Act (RCRA) has exempted certain wastes associated with the exploration and production of crude oil, natural gas, and geothermal resources from hazardous waste Subtitle C regulations. However, the exemption is limited in scope and does not cover all wastes generated in the oil field. The EPA recognizes that the oilfield produces large volumes of waste that are typically non-toxic or have a low toxicity value as normally regulated by RCRA. With this understanding, the EPA has exempted wastes that are "intrinsic and uniquely associated with oil and gas exploration."

B. In general, the exempt status of an E&P waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic. For example, some exempt E&P wastes might be harmful to human health and the environment, and many non-exempt wastes might not be as harmful. The following simple rule of thumb can be used to determine if an E&P waste is exempt or non-exempt from RCRA Subtitle C regulations:

1. Has the waste come from down-hole, i.e., was it brought to the surface during oil and gas E&P operations?
2. Has the waste otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product?
3. If the answer to either question is yes, then the waste is likely considered exempt from RCRA Subtitle C regulations. It is important to remember that all E&P wastes require proper management to ensure protection of human health and the environment.

C. Exempt and non-exempt wastes
In its 1988 regulatory determination, EPA published the following lists of wastes that were determined to be either exempt or non-exempt. These lists are provided as examples of wastes regarded as exempt and non-exempt and should not be considered to be comprehensive. The exempt waste list applies only to those wastes generated by E&P operations. Similar wastes generated by activities other than E&P operations are not covered by the exemption.

1. Exempt Exploration and Production Wastes
   - **a)** Produced Water
   - **b)** Drilling fluids
   - **c)** Drill cuttings
   - **d)** Rigwash
   - **e)** Drilling fluids and cuttings from offshore operations disposed onshore

- **f)** Geothermal production fluids
- **g)** Hydrogen sulfide abatement wastes from geothermal energy production
- **h)** Well completion, treatment and stimulation fluids
- **i)** Basic sediment, water, and other tank bottoms from storage facilities that hold product and exempt waste
- **j)** Accumulated materials such as hydrocarbons, solids, sands and emulsion from production separators, fluid treating vessels, and production impoundments
- **k)** Pit sludges and contaminated bottoms from storage or disposal of exempt wastes
- **l)** Gas plant dehydration wastes, including glycol-based com- pounds, glycol filters, and filter media, backwash, and molecular sieves
- **m)** Workover Wastes
- **n)** Cooling tower blowdown
- **o)** Gas plant sweetening wastes for sulfur removal, including amines, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge
- **p)** Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)
- **q)** Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation
- **r)** Produced sand
- **s)** Packing fluids
- **t)** Hydrocarbon-bearing soil
- **u)** Pigging wastes from gathering lines
- **v)** Wastes from subsurface gas storage and retrieval, except for the non-exempt wastes listed below.
- **w)** Constituents removed from produced water before it is injected or otherwise disposed of
- **x)** Liquid hydrocarbons removed from the production stream but not from oil refining
- **y)** Gases from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons
- **z)** Materials ejected from a producing well during blowdown
- **aa)** Waste crude oil from primary field operations
- **bb)** Light organics volatilized from exempt wastes in reserve pits, impoundments, or production equipment

2. Non-Exempt Wastes

- **a)** Unused fracturing fluids or acids
- **b)** Gas plant cooling tower cleaning wastes
- **c)** Painting wastes
- **d)** Waste solvents
- **e)** Oil and gas service company wastes such as empty drums, drum rinsate,

sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids

f) Vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste

g) Refinery wastes

h) Liquid and solid wastes generated by crude oil and tank bottom reclaimers

i) Used equipment lubricating oils

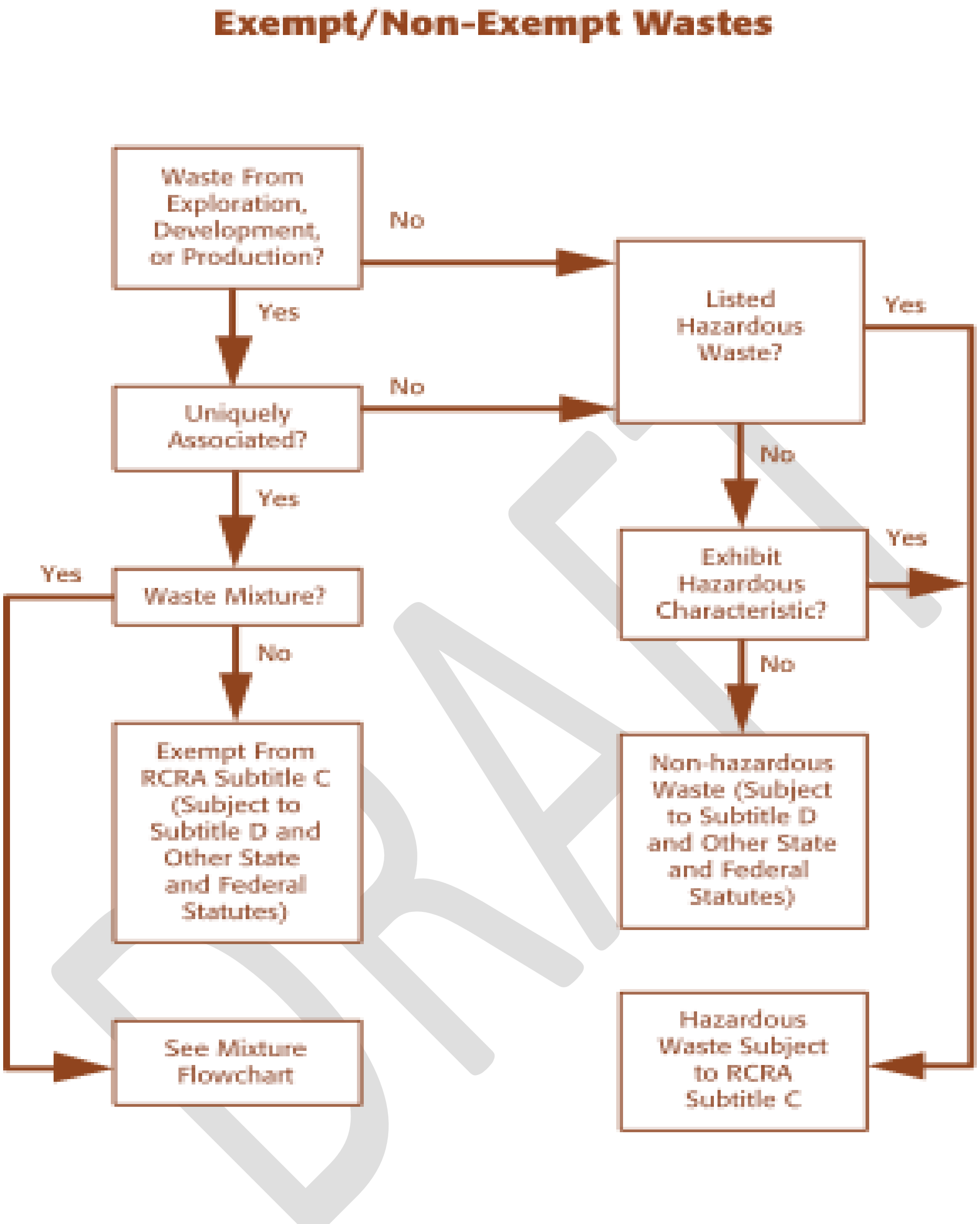
j) Waste compressor oils, filters, and blowdown

k) Used hydraulic fluids

l) Waste in transportation pipeline related pits

m) Caustic or acid cleaners

n) Boiler cleaning wastes



D. Mixing Wastes

1. Mixing wastes, particularly exempt and non-exempt wastes, creates additional considerations. Determining whether a mixture is an exempt or non-exempt waste requires an understanding of the nature of the wastes prior to mixing and, in some instances, might require a chemical analysis of the mixture. Whenever possible, avoid mixing non-exempt wastes with exempt wastes. If the non-exempt waste is a listed or characteristic hazardous waste, the resulting mixture might become a non-exempt waste and require management under RCRA Subtitle C regulation. Furthermore, mixing a characteristic hazardous waste with a non-hazardous or exempt waste for the purpose of rendering the hazardous waste non-hazardous or less hazardous might be considered a treatment process subject to appropriate RCRA Subtitle C hazardous waste regulation and permitting requirements.

2. Below are some basic guidelines for determining if a mixture is an exempt or non-exempt waste under the present mixture rule.

a) A mixture of an exempt waste with another exempt waste remains exempt. For example: A mixture of stimulation fluid that returns from a well with produced water results in an exempt waste..

b) Mixing a non-hazardous waste (exempt or non-exempt) with an exempt waste results in a mixture that is also exempt. For example: If non-hazardous wash water from rinsing road dirt off equipment or vehicles is mixed with the contents of a reserve pit containing only exempt drilling waste, the wastes in the pit remain exempt regardless of the characteristics of the waste mixture in the pit.

c) If, after mixing a non-exempt characteristic hazardous waste with an exempt waste, the resulting mixture exhibits any of the same hazardous characteristics as the hazardous waste (ignitability, corrosivity, reactivity, or toxicity), the mixture is a non-exempt hazardous waste.

(1) Example: If, after mixing non-exempt caustic soda (NaOH) that exhibits the hazardous characteristic of corrosivity in a pit containing exempt waste, the mixture also exhibits the hazardous characteristic of corrosivity as determined from pH or steel corrosion tests, then the entire mixture becomes a non-exempt hazardous waste.

(2) Example: If, after mixing a non-exempt solvent containing benzene with an exempt waste also containing benzene, the mixture exhibits the hazardous characteristic for benzene, then the entire mixture becomes a non-exempt hazardous waste.

d) If, after mixing a non-exempt characteristic hazardous waste with an exempt waste, the resulting mixture does not exhibit any of the same characteristics as the hazardous waste, the mixture is exempt. Even if the mixture exhibits some other characteristic of a hazardous waste, it is still exempt.

(1) Example: If, after mixing non-exempt hydrochloric acid (HCl) that only exhibits the corrosive characteristic with an exempt waste, the mixture does not exhibit the hazardous characteristic of corrosivity but does exhibit some other hazardous characteristic such as toxicity, then the mixture is exempt.

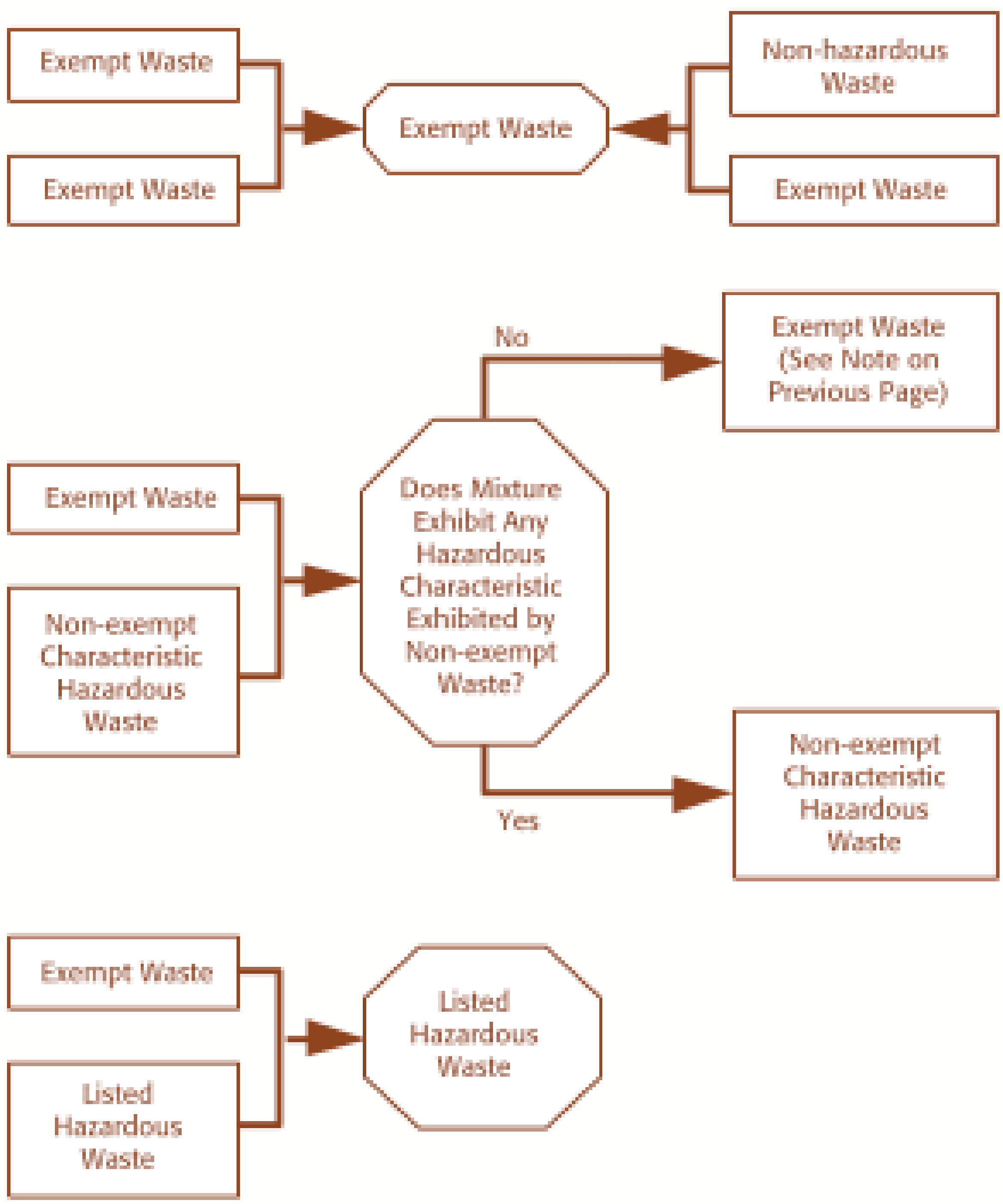
(2) Example: If, after mixing a non-exempt waste exhibiting the hazardous characteristic for lead with an exempt waste exhibiting the characteristic for benzene, the mixture exhibits the characteristic for benzene but not for lead, then the mixture is exempt.

Generally, if a listed hazardous waste is mixed with an exempt waste, regardless of the proportions, the mixture is a non-exempt hazardous waste. For example: If any amount of leaded tank bottoms from the petroleum refining industry (listed as waste code K052) is mixed with an exempt tank bottom waste, the mixture is considered a hazardous waste and is therefore non- exempt.

e) It is also important to emphasize that a mixture of an exempt waste with a listed hazardous waste generally becomes a non-exempt hazardous waste regardless of the relative volumes or concentrations of the wastes. However, if the listed hazardous waste was listed solely for one or more of the characteristics of ignitability, corrosivity, or reactivity, then a mixture of this waste with an exempt waste would only become non-exempt if the mixture exhibits the characteristic for which the hazardous waste was listed (i.e., if the mixture is ignitable, corrosive, or reactive).

f) Similarly, if a mixture of an exempt waste with a non-exempt characteristic hazardous waste exhibits any of the same hazardous waste characteristics as the hazardous waste, or if it exhibits a characteristic that would not have been exhibited by the exempt waste alone, the mixture becomes a non- exempt hazardous waste regardless of the relative volumes or concentrations of the wastes. In other words, for any of these scenarios, the wastes could become non-exempt even if only one barrel of hazardous waste were mixed with 10,000 barrels of exempt waste.

Possible Waste Mixtures and Their Exempt and Non-Exempt Status



E. Suggested E&P Waste Management Practices

1. Size reserve pits properly to avoid overflows
2. Use closed loop mud systems when practical, particularly with oil-based

muds.

3. Review material safety data sheets (MSDSs) of materials used, and select less toxic alternatives when possible.
4. Minimize waste generation, such as by designing systems with the smallest volumes possible (e.g., drilling mud systems).
5. Reduce the amount of excess fluids entering reserve and production pits.
6. Keep non-exempt wastes out of reserve or production pits.
7. Design the drilling pad to contain stormwater and rigwash.
8. Recycle and reuse oil-based muds and high density brines when practical.
9. Perform routine equipment inspections and maintenance to prevent leaks or emissions.
10. Reclaim oily debris and tank bottoms when practical.
11. Minimize the volume of materials stored at facilities.
12. Construct adequate berms around materials and waste storage areas to contain spills.
13. Perform routine inspections of materials and waste storage areas to locate damaged or leaking containers.
14. Train personnel to use sensible waste management practices.

VII. NATURALLY OCCURING RADIOACTIVE MATERIAL

A. Naturally Occurring Radioactive Materials (NORM), are natural materials which emit ionizing radiation. NORM is found throughout our environment as well as in association with some oil and gas production operations.

B. NORM may be found where scale and sludge deposits in surface equipment such as separators, heater treaters, pumps, tubing, etc. Therefore, surveys should be conducted on all surface equipment prior to any maintenance activities until it has been determined that NORM is not present from that specific reservoir.

C. Employees should perform the following when performing maintenance activities on equipment that may contain NORM,:

1. Do not eat, drink, smoke, dip or engage in any other ingesting activities while working on equipment containing NORM. Once work is completed, leave the area and wash hands and face with soap and warm water;
2. Keep open cuts and sores covered;
3. Keep hands away from eyes and mouth while working or when wearing protective gloves or other equipment; and
4. Wear appropriate clothing and protective equipment as instructed by health and safety officials.

VIII. MIGRATORY BIRDS

A. In 1918, the United States Congress enacted the Federal Migratory Bird Treaty Act which provides for the controlled harvest and protection of migratory birds. The Act makes the illegal death of any migratory bird a violation of Federal law, punishable by up to $15,000 in fines and possible criminal prosecution. The law is enforced by the U.S. Fish and Wildlife Service, a branch of the U.S. Department of the Interior.

B. The enforcement of this Act has increased in recent years with several operators being found guilty of illegally taking or killing migratory birds which have been injured or killed as a result of contact with oil or saltwater in pits or open tanks. Nearly all birds of the Mid-Continent area are protected under the Act, including the common sparrow.

C. Cover materials

1. Cover open top tanks and permanent pits, such as skimming pits or emergency saltwater storage pits with a net, screen, or other material.

2. Materials to cover open top tanks include solid wood, steel, or fiberglass covers, or flexible screen or net. Flexible netting includes chicken wire and polypropylene. However, it chicken wire is cumbersome to work with and doesn’t last long. Polypropylene netting with a one-inch mesh size is popular for open top tanks. Netting with a one-inch mesh is needed to prevent small birds from getting into the tank.
3. The best way to cover pits is with the polypropylene net using a tie down and support system to secure the net. Securing the net extends its life. Some operators may cover their tanks themselves or may hire one of several companies in the area that furnish and install protective netting.