Abt Associates Inc.

memorandum

Environment and Resource Division
4800 Montgomery Lane, Suite 600 ▪ Bethesda, MD 20814-5341 ▪ (301) 913-0500

Date: June 6, 2008

To: Mark Howard, U.S. EPA / Office of Emergency Management

From: Andrea Schnitzer, Stephanie Ball, John Bovay, Isabelle Morin, and Kristina Watts

Subject: Review of State Regulations Pertaining to Oil Spill Prevention at Onshore Production Facilities and Produced Water Containers (Contract #68-W03-020, WA 2-05, TD #11)

On October 1, 2007, EPA published a proposed rule to amend the Spill Prevention, Control and Countermeasure (SPCC) regulation at 40 CFR part 112. The proposed rule includes amendments pertaining to onshore oil production facilities and to produced water containers at these facilities. EPA received a number of comments on the proposed approach for onshore oil production facilities that noted that state programs already cover onshore oil production facilities and produced water tanks, and therefore, the federal SPCC regulation is unnecessarily burdensome.

EPA has requested that Abt Associates review state programs to assess: how many and which states have spill prevention regulations that address onshore oil production facilities; how requirements under these regulations compare to SPCC requirements; and how the regulations address produced water tanks.

EPA is also interested in understanding state programs applicable to onshore oil production facilities more broadly, for example to understand how states define marginal or stripper wells and oil severance taxes or royalty payments (in particular for oil recovered from produced water).

Finally, this memo summarizes findings from our review of oil production regulations for the 31 oil-producing states. A summary of information collected for each state reviewed is provided in Appendix A. The memo also describes the regulation of onshore oil production facilities under federal and state National Pollutant Discharge Elimination System (NPDES) and Underground Injection Control (UIC) programs.[1] This research has been conducted to respond to commenters that have claimed that these programs and the aforementioned state programs can serve to protect waters of the United States in lieu of the SPCC program. Commenters have further claimed that these program's requirements are in parity with the SPCC program.

[1] Wastes related to oil and gas exploration and production, including produced water, are exempt from the hazardous waste management requirements under Subtitle C of the Resource Conservation and Recovery Act (RCRA).

This memo is organized into three main parts:

- *Part I.* Section 1 outlines the scope of the study and highlights the issues considered in our review of state regulations, while Section 2 describes data sources we used to identify and access state regulations applicable to oil production facilities;
- *Part II.* Sections 3 through 5 summarize key findings of our comparative review of spill prevention requirements under state regulations (Section 3), NPDES programs (Section 4), and UIC programs (Section 5), against SPCC requirements.
- *Part III.* Finally, Sections 6 and 7 summarize findings related to definitions of marginal or stripper wells, and oil severance tax or royalty fee, respectively.

A conclusion is included in Section 8, summarizing key findings.

1. Scope of Review

This review focuses on state regulations aimed at preventing oil spills from **onshore** production facilities. In identifying and reviewing relevant regulations for each of the 31 oil-producing states, Abt Associates considered the following items:

1. Overall scope of regulations addressing onshore oil production facilities
2. Regulations addressing produced water
3. Wording of statements of general duty to prevent discharges of produced fluids or oil to waters of the State
4. Specific Requirement of Secondary Containment around Produced Water Tanks
5. Specific requirements for design of disposal pits (produced water pits)
6. Oil spill reporting requirements
7. Comparison between state and SPCC requirements pertaining to:
    a. Provision of general secondary containment to prevent offsite migration of produced fluids (similar to §112.7(c))
    b. Preparation and maintenance of a written plan (similar to §112.3)
    c. Review of the facility, review of the plan, and/or certification of the plan by a Professional Engineer (similar to §112.3(d))
    d. Report specific discharges to the Agency and indicate actions taken to correct the problems (similar to §112.4)
    e. Amend facility plan whenever there are material changes at the facility (similar to §112.5)
    f. Include in the plan a prediction of direction and rate of flow, and total quantity of oil that could be discharged from the facility as a result of each type of major equipment failure (similar to §112.7(b))
    g. Employ alternative methods of secondary containment if secondary containment is found to be impracticable (similar to §112.7(d))
    h. Retain records for a specific period of time (similar to §112.7(e))

i. Personnel training and discharge prevention procedures (similar to §112.7(f))

j. Evaluate containers for risk of discharge or failure due to brittle fracture or other catastrophe (similar to §112.7(i))

k. Discuss conformance with other applicable discharge prevention and containment requirements (§112.7(j))

l. Provide alternative requirements for general secondary containment for qualified oil-filled operational equipment (§112.7(k))

m. Control of drainage from tank batteries and separation/treating areas (§112.9(b))

n. Container construction, design, and material (§112.9(c)(1))

o. Provision of sized secondary containment around tank battery, separation, and treating facility installations (§112.9(c)(2))

p. Visual inspection of each container for deterioration and maintenance needs (§112.9(c)(3))

q. Engineering of installation to prevent overfills (§112.9(c)(4))

r. Periodic inspection of aboveground valves, piping, etc. (§112.9(d)(1))

s. Inspection of saltwater disposal facilities (§112.9(d)(2))

t. Flowline maintenance program (§112.9(d)(3))

The seven items listed above are discussed in our summary of findings presented in Section 3.

We also reviewed overall federal and/or state requirements under the NPDES and UIC programs to identify similarity or areas of overlap with SPCC requirements. Findings pertaining to review of the two types of programs are presented in Section 4 and 5 of this memo, respectively.

We reviewed state-specific definitions of “marginal” or “stripper” wells to determine how these definitions may differ from the definitions used by the Department of Energy or Internal Revenue Service. Our findings are summarized in Section 6 of this memo.

Finally, we reviewed information available on severance tax and/or royalty fees imposed by each state to determine whether states define different types of oils for the purpose of levying taxes or fees on oil production, including whether the amount of oil recovered in produced water is taxed by state authorities. Our findings are summarized in Section 7 of this memo.

Note that our review focused on state regulatory requirements. We generally did not consider non-binding guidance or recommended practices, except where they directly inform how regulations are implemented. Furthermore, our review is based on publicly available information found on websites for each state agency or program. We did not contact state officials or industry representative to discuss and confirm our findings. However, Abt Associates did use data provided by IOGCC to verify the information summarized in this paper.

2. Data Sources and Methodology

In November 2006, Abt Associates carried out a preliminary review of regulations and programs in the 17 states that produce the greatest volumes of oil. At the time, the review considered broad issues pertaining to oil production facilities, gathering lines, and natural gas facilities. Abt Associates used this information as a starting point to identify information relevant to the current review.

Abt Associates used Argonne National Laboratory's Produced Water Management Information System (PWMIS) to identify additional relevant state regulations.[2] This source provides links to state programs as well as summarizes produced water management practices and associated regulations. We also consulted recent reviews conducted by the State Review of Oil and Natural Gas Environmental Regulation (STRONGER) workgroup. The purpose of the workgroup is to document environmental regulations associated with the exploration, development, and production of crude oil and natural gas. We used recent STRONGER reports to further inform our understanding of requirements applicable to oil production facilities. The STRONGER reports were also referenced by IOGCC and DOE in the supplementary information submitted to EPA after the close of the comment period.[3]

Using the links identified through these sources, EPA program pages, and Internet searches, we reviewed regulations, program description, guidance or general permit application documents available through the government websites. Sources of information are recorded in our summary of each state, which is included in Appendix A.

3. Summary of Findings from Review of State Regulations

This section discusses overall findings of our review of state regulations across each of the topic areas listed in Section 1.

3.1 Overall Scope of Regulations Addressing Oil Production Facilities

In general, oil producing states have spill prevention regulations that specifically address oil production facilities. These regulations are implemented by the state's oil and gas commission, which is charged with overseeing oil and gas production and recording of leases within each state, and/or by the state's environmental agency.[4]

Overall, the state programs cannot serve as a replacement for the SPCC program. As summarized below, state spill prevention requirements vary greatly from state to state and are generally less specific and not as comprehensive than SPCC requirements.

3.2 Regulations Addressing Produced Water

Most states we reviewed specifically address "produced water" in some capacity. Some states specifically address produced water spill remediation (AR, IL), and treatment and disposal (AK, AL, CO, IL, KY, LA, MT, SD). Several states also explicitly address reuse and recycling of produced water. Pennsylvania, for example, requires that facilities collect brine and other

---

[2] Site last accessed on March 4, 2008 at http://web.evs.anl.gov/pwmis/regs/index.cfm

[3] See "Supplemental DOE Information Relating to Oil and Gas Industry Relief from Some SPCC Requirements" (May 16, 2008) and "Response to Comments from the U.S. Environmental Protection Agency on Comments by the Interstate Oil and Gas Compact Commission to Spill Prevention Control and Countermeasure Proposed Rules" (May 20, 2008)

[4] e.g., Department of Environmental Quality, Department of Environmental Protection, Commission on Environmental Quality, Department of Natural Resources.

produced fluids, and that they prevent discharge. Pennsylvania also specifies the requirements for a pit to store produced water (as do MT and MS).

Some states do not have specific spill prevention requirements for produced water. For instance, Kansas, Nebraska and Virginia only mention the term when referring to pits and pit lining, and California does not use the term at all. Instead, the state of California discusses "waste water" more generally, and has few regulations specifically addressing wastewater from production facilities. Florida uses the broader term "produced fluids" and Indiana only discusses "waste liquids".

3.3 General Duty to Prevent Discharges of Produced Fluids or Oil to Waters of the State

Most states we reviewed have regulations that specifically address prevention of discharge into both groundwater and surface water (or "waters of the state"); some only prohibit discharge into surface water (WY). All states reviewed prohibit pollutant or waste discharges at least generally.

3.4 Specific Requirement of Secondary Containment around Produced Water Tanks

Most states have some requirements for secondary containment. (See section 3.7.6 for a summary of these requirements.) Colorado is the only state that has a specific requirement for secondary containment around produced water tanks, which reads "Secondary containment shall be constructed or installed around tanks containing crude oil, condensate or produced water with greater than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS)." In other states, produced water containers are not addressed specifically and separately but are instead included along with other components of the tank battery.

However, the Bureau of Land Management (BLM)'s production permits often require containment for all tanks, including produced water tanks, for any production on federal lands, regardless of state regulations. Produced water tanks are included because although accumulation of oil is minor on a daily basis over several months, operators do not check their water tanks often, and significant oil accumulation can occur even at well-managed operations.5 BLM staff noted that BLM specifically references SPCC requirements in their BMPs for oil production permits.

3.5 Specific Requirements for Design of Disposal Pits

Disposal pits are one aspect of onshore oil production facilities for which there seems to be a full array of specific regulatory requirements, although requirements for the construction and design of disposal pits vary significantly across states we reviewed.

New Mexico, for example, requires disposal pits to be registered, fenced, and lined, and provides other regulations to protect birds and ensure that waste remains within the pit. North Dakota, Nebraska and Montana require that pits be fenced, screened, or netted and lined with an impermeable liner. The netting requirement is most often used to protect waterfowl from landing in these ponds and becoming oiled. Again, this requirement supports EPA's argument that produced water containers/pits often contain oil after primary separation. Montana also indicates that if the bottom of the pit or pond is underlain by porous, permeable, sharp, or

[5] Conversation between Mark Howard and Bill Jawiske 6/3/2008.

jagged material, the pit or pond must be lined with at least three inches of compacted betonite prior to setting the impermeable synthetic liner.

In Oklahoma, steel pits must have a minimum wall thickness of three-sixteenths inch, and concrete pits must be steel-reinforced and have a minimum wall thickness of six inches. Illinois and South Dakota require that pits be lined with at least a “20 mil thickness liner”. Virginia requires hat pits have liners 10 mil or thicker and be constructed so as to maintain a two-foot freeboard. Nebraska also requires that pits be bermed or diked and have at least two feet of freeboard between the normal operating level of the water in the pit and the top of the banks, dikes or berms.

Pennsylvania requires that pits be lined, covered, and backfilled to prevent runoff, and adds several other measures to ensure that leaks do not occur. Texas requires pits of certain types to be used for certain types of storage, but does not provide any specific design criteria; Ohio requires pits or tanks of sufficient size, but provides no further design criteria. Michigan and Nevada only require that the pit be impervious so as to protect freshwater and other resources. Indiana’s regulation offer specific siting requirements, such as requiring the pit to be located 100 feet away from any stream, lake, river, or drainage way. Wyoming requires very specific characteristics for liners. For instance, the rule requires that liners created from synthetic materials must be 9-12 millimeter thick, have a puncture strength of 60 pounds, and be greater than 20% elongation at failure. Alaska states only that “the confining surface of a reserve pit must be impervious.” Tennessee’s rule has multiple general requirements relating to pit construction, providing ample latitude for enforcement by the office of oil and gas. Under West Virginia statute, a pit liner is required to be used whenever the pit is not naturally impervious.

We could not identify specific pit requirements in Alabama, Colorado, Florida, Kentucky, Louisiana, Mississippi, Missouri, New York, Texas and Utah.

3.6 Oil Spill Reporting Requirements

All producing states require reporting of discharges or spills to state authorities. These reporting requirements are in addition to federal oil spill reporting requirements under 40 CFR part 110. Some states require all spills to be reported regardless of the volume and affected medium (PA, NM), but most states only require spills to land above a certain volume threshold to be reported.

All states require that *all spills of any size that impact state waters* be reported immediately. Most states require a verbal notification within 24 hours, to be followed by a written report, filed 10 to 15 days later.

3.7 Comparison of State Regulations to SPCC Requirements

This section provides a summary of findings regarding each of the nine specific SPCC requirements listed in Section 1 of this memo. For each item, we summarize the applicable SPCC requirement and discuss, through examples drawn from selected states, whether and how the SPCC requirement is similarly addressed through state regulations. Table 1, at the end of this section, presents this information across the 31 states we reviewed.

3.7.1 Preparation and maintenance of a written plan (similar to §112.3)

The SPCC rule requires facilities to prepare a Spill Prevention, Control, and Countermeasure Plan and amend it if necessary to ensure compliance with the rule.

Many states require facilities to prepare and maintain some version of a SPCC Plan. Kentucky explicitly states that SPCC plans be developed and implemented when required under 40 CFR part 112. Florida requires that all operators of oil production facilities "devise and submit to the Department a plan designed to prevent spills of crude oil and associated fluids and to expeditiously remove these fluids from the environment should a spill occur."

California, Louisiana, North Dakota and Utah have requirements for contingency plans but do not provide specific details about the plan content; Oklahoma requires a contingency plan for operation in hydrogen sulfide areas; New Mexico requires oil production facilities to prepare an "abatement plan," although the requirements of this plan are not detailed; Mississippi states a Supervisor has the right to remove pollutants in accordance with a "contingency plan for combating oil spills" but does not provide any further detail; Pennsylvania requires development of a control and disposal plan relating to activities utilizing pollutants; Virginia requires each application for a permit or permit modification to include an operations plan.

Other states require certain types of facilities, but not specifically oil and gas production facilities, to prepare a written contingency or abatement plan for oil spills into water. The types of facilities listed include: underground porosity storage facilities (KS); used oil processors and re-refiners (NY, OH).

Finally, several states require development of a written plan that is much smaller in scope than a SPCC Plan. Specifically, Michigan requires a secondary containment plan; Colorado requires a "remediation workplan" if a spill has occurred; Oklahoma requires complete construction plans, drawings and written specifications for a proposed facility to be submitted to the Manager of Pollution Abatement for review and approval.

We were not able to locate requirements for preparation of any written plan for several states: AK, AL, AR, AZ, IL, IN, MO, MT, NE, NV, SD, TN, TX, WV, WY.

3.7.2 Review of the facility, review of the plan, and/or certification of the plan by a Professional Engineer (similar to §112.3(d))

The SPCC rule requires that, unless the facility is a qualified facility (with storage not exceeding 10,000 gallons and meeting the reportable discharge history criterion), the SPCC Plan must be reviewed and certified by a Professional Engineer. This certification reflects that the Professional Engineer "is familiar with the requirements of this part… That he or his agent has visited and examined the facility… That the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part… That procedures for required inspections and testing have been established; and… That the Plan is adequate for the facility."

New Mexico requires that new surface waste management facilities include with the permit application for the facility "engineering designs, certified by a registered professional engineer, including technical data on the design elements of each applicable treatment, remediation and disposal method and detailed designs of surface impoundments."

Kentucky requires that the SPCC plan be reviewed and certified by a Registered Professional Engineer. Mississippi only requires that a supervisor or authorized representative review a facility's secondary containment plan. The state of Oklahoma requires all plans, drawings, and specifications be prepared by or under the supervision of a qualified expert.

Most states do not include any requirement similar to the SPCC rule for review of the facility or plan, or certification of the plan by a Professional Engineer (AK, AL, AR, AZ, CA, CO, FL, IL, IN, KS, LA, MA, MO, MT NE, NV, NY, ND, OH, PA, SD, TN, TX, UT, VA, WV, WY)

3.7.3 Report specific discharges to the Agency and indicate actions taken to correct the problems (similar to §112.4)

The SPCC rule requires facilities to submit information to the EPA Regional Administrator within 60 days from the time of certain reportable discharges. The required submission includes basic facility information; handling and storage capacity; corrective actions and countermeasures taken including equipment repair and replacement; physical facility description, including maps or diagrams; the cause of the discharge; additional preventive measures taken; other pertinent information. This information must also be sent to the appropriate state agency in charge of oil pollution control activities.

Alabama, Alaska, Arizona, Arkansas, Colorado, Michigan, Mississippi, Montana, New Mexico, New York, Oklahoma, Pennsylvania, South Dakota, Texas, Utah, Virginia and Illinois require a written report including actions taken to correct the problem. West Virginia requires submittal of a complete copy of the SPCC Plan with any amendments as required under 40 C.F.R. 112, or Best Management Plan (BMP) as required under any permit, for discharges of more than 1000 U.S. gallons into the waters of the state in a reportable discharge or discharged oil or other pollutants into the waters of the state in two reported discharges within any twelve month period. Indiana, Kansas, Nevada require a remediation report, but do not require facilities to report further action to prevent future discharges.

While all state regulations contain requirements for reporting spills, according to our findings, several states do not require facilities or owner/operators to report actions to be taken as a result of a spill. (CA, FL, KS, KY, LA, MO, ND, OH, TN, WY)

3.7.4 Amend facility plan whenever there are material changes at the facility (similar to §112.5)

The SPCC rule requires that facility operators amend the Plan whenever “there is a change in the facility design, construction, operation, or maintenance that materially affects its potential for a discharge as described in §112.1(b).” Additionally, the Plan must be reviewed at least once every five years and technical amendments must be certified.

Florida requires that operators update their plans’ “field maps showing wells, flowlines, tank batteries, access roads, treating facilities, gathering lines, and associated facilities.” Some states require plan amendment whenever “applicable regulations are revised; the plan fails in an emergency; the facility changes - in its design, construction, operation, maintenance, or other circumstances - in a way that materially increases the potential for fires, explosions, or releases of used oil, or changes the response necessary in an emergency; the list of emergency coordinators changes; or the list of emergency equipment changes. (NY, OH) North Dakota adds to this list “[whenever] the facility permit is revised”. New Mexico also allows operators to request to modify their plan, and requires modification if monitoring data or any other information indicates that the abatement plan is ineffective. Louisiana requires that spill contingency plans be updated when there are changes or modifications at a facility.

In Alaska, if an operator wants to make a substantive change in a program or activity for which commission approval is required, complete details of the well's current condition and the proposed change must be submitted to the commission. However, there is no reference to a requirement for a written plan, similar to the SPCC requirement under §112.3.

While the states of Oklahoma and Pennsylvania require a written plan, their regulations provide no reference regarding plan amendments. Some states do not require any preparation of a written plan and therefore do not require plan amendment (AL, AR, AZ, CA, CO, IL, IN, KY, MI, MO, MS, MT, NE, NV, SD, TN, TX, UT, VA, WV, WY).

3.7.5 <u>Include in the plan a prediction of direction and rate of flow, and total quantity of oil that could be discharged from the facility as a result of each type of major equipment failure (similar to §112.7(b)).</u>

The SPCC rule requires that, "[w]here experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge)," the Plan must include "a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure."

New Mexico requires site investigation work to define hydrology and potential effects on fish and other wildlife, and Kentucky specifically requires prediction of the quantity of oil that would be spilled and the direction of flow should a tank rupture or overflow.

No state regulations were found requiring such predictions to be made (AK, AL, AR, AZ, CA, CO, FL, IL, IN, KS, LA, MI, MO, MS, MT, NE, NV, NY, ND, OH, OK, SD, TN, TX, UT, VA, WV, WY).

3.7.6 <u>Provision of general secondary containment to prevent offsite migration of oil and produced fluids (similar to §112.7(c))</u>

The SPCC rule describes secondary containment as "appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in §112.1(b)…The entire containment system, including walls and floor, must be capable of containing oil and constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs…" At a minimum, one of the following must be used for onshore facilities: dikes, berms, or retaining walls sufficiently impervious to contain oil; curbing, culverting, gutters, or other draining systems; weirs, booms, or other barriers; spill diversion ponds; retention ponds; or sorbent materials. For offshore facilities: curbing or drip pans; or sumps, and collection systems.

Overall, most state regulations have some requirements for secondary containment. Some have very specific rules that appear to be similar to, or at least as stringent as, the SPCC requirements while others do not. In some cases, the state requirements refer to SPCC requirements directly. Pennsylvania requires that "If an owner or operator uses a tank with a capacity of at least 660 gallons or tanks with a combined capacity of at least 1,320 gallons to contain oil produced from a well, the owner or operator shall construct and maintain a dike or other method of secondary containment which satisfies the requirements under 40 CFR 112 (relating to oil pollution prevention)." Alabama, Arizona, Indiana, and Michigan have specific berm and dike construction requirements. Other states require secondary containment similar to the SPCC requirements (KY, NM, WY). Nevada only requires secondary containment when the tanks are located a specific distance from certain locations, such as churches or schools. California, Kansas, Oklahoma, Tennessee and West Virginia simply state that secondary containment is required to prevent spills, and Louisiana provides similar general language.

Some states do not specify any secondary containment requirements for tanks (AK, IL, MS, MO, MT, ND, NE, NY, SD).

3.7.7 Employ alternative methods of secondary containment if secondary containment is found to be impracticable (similar to §112.7(d)).

The SPCC rule requires that, when secondary containment is impracticable, the Plan must describe why containment measures are not practicable; for bulk storage containers, conduct periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; provide an oil spill contingency plan under the guidance of 40 CFR part 109; and provide "[a] written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful."

New Mexico allows operators to file a petition for the use of alternative abatement procedures, and also to propose that abatement is technically unfeasible. Mississippi allows operators to not build the required dikes or firewalls if they create a plan whereby oil tanks or batteries are protected using another method. The Pennsylvania regulation states that "the owner or operator shall construct and maintain a dike or other method of secondary containment which satisfies the requirements under 40 CFR 112 (relating to oil pollution prevention) around the tank or tank batteries", implying consistency with requirements of §112.7(d).

We were not able to find mention of alternative methods of secondary containment in many state regulations (AK, AL, AR, AZ, CA, FL, IL, IN, KS, KY, LA, MI, MO, MT, ND, NE, NV, NY, OH, OK, SD, TN, TX, UT,VA, WV, WY).

3.7.8 Retain records for a specific period of time (similar to §112.7(e))

The SPCC rule requires that records of inspections and testing are retained for a period of three years. Of the states that provide a similar requirement, the time period ranges from two to seven years.

Mississippi regulations require that all reports required by the Board be kept on file and available for inspection for at least two years. Kansas requires that persons who transport, store, possess, or dispose of "fluids produced in association with the production of oil or gas" maintain records of this activity for at least three years. Texas requires that retention of records, forms, and documents which are required to be filed with the commission for a period of three years or longer. Kentucky requires that records of inspections and gathering lines repairs be maintained for 3 years. Louisiana requires the maintenance of test and inspection records for three years. Virginia specifically requires tanks inspection records, blasting records, and driller's logs and any other surveys be retained for three years.

South Dakota requires that producers, injectors, transporters, storers, refiners, gasoline or extraction plant operators, and initial purchasers of oil or gas keep the books and records covering their operations for not less than five years. Alaska also requires record retention for not less than five years while Arizona requires retention for at least six years. New York requires its used oil processors and re-refiners to maintain their records for seven years.

Certain states require records be kept for specific activities or equipment: Oklahoma requires that reports pertaining to disposal of waste oil be retained for a minimum of three years; Pennsylvania requires retention of records specifically and only for gas wells for a period of seven years; Colorado specifically requires pressure tests of flowline records to be maintained for at least three years.

We were unable to identify a requirement pertaining to retention of records for most states (AL, AR, CA, FL, IL, IN, MI, MO, MT, NE, NV, NM, ND, OH, TN, UT, WV, WY).

3.7.9 Personnel training and discharge prevention procedures (similar to §112.7(f))

The SPCC rule requires that oil-handling personnel are trained in the operation and maintenance of equipment to prevent discharges; discharge procedures; applicable pollution control laws and regulations; general facility operations; and the contents of the SPCC Plan. Each facility must designate a person responsible for discharge prevention; and annual discharge prevention briefings must be conducted.

North Dakota specifies that facilities that treat, store, and dispose of hazardous wastes train personnel extensively in a classroom and on-the-job, including training in emergency response procedures. New Mexico requires a similar program for surface waste management facilities, but not for E&P facilities. Mississippi requires that personnel be "thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of waste and pollution." Kentucky refers to the SPCC rule, and asks that operating personnel be familiarized with their facility's SPCC Plan. Tennessee requires that all personnel, including operators and service personnel, "be trained in the prevention of spills and made aware of the consequences of spillage." Colorado only mentions that the training of employees is an important part of a safety program.

Oklahoma requires that operators provide appropriate H_2S training for employees who will be on-site in hydrogen sulfide areas. Utah requires a blowout prevention drill to be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties.

According to our findings, most states do not specifically require personnel training or discharge prevention procedure training (AK, AL, AR, AZ, CA, FL, IL, IN, KS, LA, MI, MO, MT, NE, NV, NY, PA, SD, TX, VA, WV, WY).

3.7.10 Evaluate field-constructed aboveground containers for risk of discharge or failure due to brittle fracture or other catastrophe (similar to §112.7(i))

The SPCC rule requires that field-constructed aboveground containers be evaluated for risk of discharge due to brittle fracture or other catastrophe, in the event that the container undergoes some physical change that may affect its risk of discharge, or has discharged oil due to brittle fracture or other catastrophe.

Louisiana requires that facilities be inspected for risk of discharge due to malfunctions, but does not mention brittle fracture. We were unable to identify state regulations requiring evaluation of containers for risk of discharge or failure due to brittle fracture or other catastrophe (AL, AK, AR, AZ, CA, FL, IL, IN, KS, LA, MI, MO, MT, NE, NV, NM, NY, ND, OH, OK, PA, SD, TN, TX, UT, VA, WV, WY).

3.7.11 Discuss conformance with other applicable discharge prevention and containment requirements (§112.7(j))

The SPCC rule requires that facilities "include in [their] Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in this part or any applicable more stringent State rules, regulations, and guidelines."

North Dakota and Ohio both allow operators to create their plans by modifying existing SPCC Plans to meet any additional state requirements. Some states (KY, PA, WV, WY) refer to the federal SPCC requirements, For instance, West Virginia requires that "Owners or operators should be aware of their responsibility to comply with spill prevention control and countermeasures plan (SPCC 40 CFR 112) requirements that regulate the prevention and containment of crude oil spills." Louisiana and Texas refer to 40 CFR part 195 when discussing the construction and maintenance of flowlines. Although these references do not mean that the states adhere to §112.7(j), they demonstrate that states have considered federal rules, including SPCC when developing their own regulations.

Most states do not require operators to discuss conformance with other applicable discharge prevention and containment requirements (AK, AL, AR, AZ, CA, CO, FL, IL, IN, KS, MS, MI, MO, MT, NE, NV, NM, NY, OK, SD, TN, TX, UT, VA, WY).

3.7.12 Provide alternative requirements for general secondary containment for qualified oil-filled operational equipment (§112.7(k))

The SPCC rule requires that facilities with qualified oil-filled operational equipment "establish and document the facility procedures for inspections or a monitoring program to detect equipment failure and/or a discharge" and, unless the facility has provided a facility response plan, provide an oil spill contingency plan under the guidance of 40 CFR part 109; and provide "[a] written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful."

A similar provision was not identified in any state regulations (AK, AL, AR, AZ, CA, CO, FL, IL, IN, KS, KY, LA, MS, MI, MO, MT, ND, NE, NM, NV, NY, OH, OK, PA, SD, TN, TX, UT, VA, WV, WY).

3.7.13 Control of drainage from tank batteries and separation/treating areas (§112.9(b))

The SPCC rule requires dikes and drains, and equivalent measures under §112.7(c)(1) be closed and sealed at all times at tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in §112.1(b), except when draining uncontaminated rainwater. Prior to drainage, the diked area must be inspected and any accumulated oil must be removed and returned to storage or disposed of in accordance with legally approved methods. Additionally, field drainage systems, oil traps, sumps or skimmers must be inspected at regular intervals and accumulated oil must be promptly removed.

In general, state regulations do not have nearly as stringent or as specific requirements for facility drainage as the SPCC rule. The Florida Administrative Code specifies that "drain lines with locked valves shall be installed through the fire walls at the lowest point of the containment facility but fluids may be drained only in accordance with NPDES and other permits." California only mentions that a drainage system for safe fluid containment is required.

We were not able to identify SPCC-like requirements specifically for controlling drainage from tank batteries for most states (AK, AZ, CO, IL, IN, KY, LA, MI, MO, MT, ND, NE, NM, NV, NY, PA, SD, TX, UT, VA, WY).

3.7.14 Container construction, design, material (§112.9(c)(1))

The SPCC rule requires that a container not be used for the storage of oil unless the "material and construction are compatible with the material stored and the conditions of storage."

Florida has a requirement similar to that in the SPCC rule that specifies that all tanks be installed, maintained, and pressure tested in accordance with generally accepted petroleum standards.

Some states discuss specific container requirements, but do not mention pressure and temperature. California requires a tank foundation of concrete or gravel. Colorado, New Mexico, and Louisiana require that tanks be constructed in accordance with published design standards. Alaska requires that all equipment be designed and protected to ensure reliable operation under the range of weather conditions expected for the specific location, and installed, operated, and maintained in accordance with good oil field engineering practices. Several other states require only that a tank's material and construction be compatible with the material stored and the conditions of storage (FL, OK, SD, UT, WV.)

Many states do not have any SPCC-like requirements dealing with container construction, design, and material (AL, AR, AZ, IL, IN, KY, KS, MI, MO, MS, MT, ND, NE, NV, NY, OH, PA, TN, TX, VA, WY).

3.7.15 Provision of sized secondary containment around tank battery, separation, and treating facility installations (§112.9(c)(2))

This SPCC provision requires that secondary containment be provided for all tank battery, separation, and treating facility installations with a secondary means of containment for the "entire capacity of the largest single container and sufficient freeboard to contain precipitation." Additionally, drainage from undiked areas must be safely confined in a catchment basin or holding pond.

Several states require secondary containment around tank batteries (which include produced water containers) and require that dikes or other approved structures have a capacity of at least 1½ times the largest tank found within the containment dike or approved structure (AL, AR, AZ, IL, MI, MS, MT, NY, SD, VA). Nebraska requires that tanks be surrounded by an earthen dike that must provide a capacity of one and one-tenth (1-1/10) times the capacity of the largest tank it surrounds, and West Virginia requires a secondary means of containment for the entire contents of the largest single tank, if feasible. New Mexico requires that the containment area be at least 110 percent of the volume of the largest tank plus the area displaced by other co-located aboveground storage tanks (ASTs).

Florida dictates that tank batteries be constructed on containment pads that are surrounded by dikes or fire walls that have the strength and size to contain two times the volume of the largest storage tank. Kentucky just refers to the SPCC rule on the matter.

Several states do not mention secondary containment requirements specific to tank battery, separation, and treating facility installations, but simply mention secondary containment in general terms (CA, CO, IN, KS, NV, OK, PA, UT, WY). Secondary containment of oil containers is not specifically covered in Ohio's Revised Code which governs oil production activity.[6]

3.7.16 Visual inspection of each container for deterioration and maintenance needs (§112.9(c)(3))

This SPCC provision requires owners/operators to "periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground."

[6] Ohio's Revised Code does not specify secondary containment provisions, except as covered generally under the general duty to prevent discharges, or subject to guidelines established by the division of mineral resources management. The ORC, however, specifies secondary containment requirements for brine and waste pits.

New Mexico and West Virginia are the only states we reviewed for which we found a specific requirement to visually inspect ASTs and all their components monthly and cathodic protection systems every 60 days. Virginia requires that permittees inspect the structural integrity of tanks and tank installations, at a minimum, annually. Florida and Missouri both require daily inspections of facilities and tanks. Missouri specifically requires that the permittee inspect for corrosion and erosion. West Virginia has the most SPCC-like requirements in that it directs facilities to visually examine tanks on a scheduled periodic basis "including the foundation and supports of tanks that are above the surface of the ground."

3.7.17 Engineering of installation to prevent overfills (§112.9(c)(4))

This SPCC provision requires that overfill be prevented using "good engineering practice." This requires either adequate container capacity if a pumper/gauger is delayed, overflow equalizing lines between containers, vacuum protection, and/or high level sensors that can send an alarm to a computer.

Several states require overfill prevention devices mentioned in the SPCC rule. The Florida Administrative Code requires that "crude oil storage tanks shall be equipped with equalizing overflow lines." Tennessee and West Virginia require the use of equalizer lines between adjacent tanks as a safeguard against overflow.

Most other states we reviewed do not specifically mention use of these devices but some states do have other provisions to prevent overfills (AR, AZ, CA, IN, MI, LA.) For instance, the Michigan Administrative Code requires that "the supervisor shall require the installation of an automatic facility shutdown system if the facility has a throughput of liquids in a 24-hour period that exceeds the containment volume of the secondary containment area." Arizona has similar requirements. Louisiana states that the appropriate controls and practices to prevent spills and overflows from tank or containment systems may include overfill prevention controls such as level sensing devices, high level alarms, and automatic feed cutoff or bypass to a standby tank.

Some states do not reference any measures to prevent overfills (AL, AK, CO, IL, KS, KY, MS, MT, NE, NV, NM, NY, ND, OH, OK, SD, TX, UT, VA, WY).

3.7.18 Periodic inspection of aboveground valves, piping, etc. (§112.9(d)(1))

The SPCC rule requires that all aboveground valves, piping, and appurtenances be regularly inspected and lists specific equipment that must be included in the inspection.

Some states we reviewed require the periodic testing of certain devices found at oil production facilities, while other states provide for inspection of facility components in general. In California, all safety systems and equipment in consolidated production facilities in urban areas must be inspected and tested every six months. In Tennessee, the frequency "should be based on the rate of deterioration of the equipment and the probability of an environmental or human health incident if the deterioration, malfunction, or any operator error goes undetected between inspections." Colorado requires that all pipes, valves and fittings be inspected at "regular intervals" while West Virginia requires inspection "periodically on a scheduled basis." Virginia regulations require only annual visual inspection of gathering pipelines.

No mention of regular inspection of oil facilities or specific equipment could be found for several states (AR, KS, KY, IL, MO, NE, NV, NY, ND, OH, OK, PA, SD, TX, UT, and WY) .

3.7.19 <u>Inspection of saltwater disposal facilities (§112.9(d)(2))</u>

The SPCC rule requires that saltwater disposal facilities be inspected often, "particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge."

Many states require inspection of saltwater treatment facilities generally (AR, OK, PA, TX, WY, NM, ND). States that have inspection requirements for saltwater treatment facilities generally do not specifically require that inspection be "frequent" or do not mention specific circumstances for these inspections such as following a sudden change in atmospheric temperature (AR, OK, PA, TX, WY, NM, ND). West Virginia's requirements for inspection of saltwater disposal facilities are identical to the federal SPCC requirements.

We were unable to find information on inspection requirements for saltwater disposal facilities for the following states: AK, AL, AZ, CA, CO, IL, IN, KY, LA, MI, MO, MT, MI, NE, NY, OH, SD, TN, VA, and UT.

3.7.20 <u>Flowline maintenance program (§112.9(d)(3))</u>

The SPCC rule requires that oil production facilities "have a program of flowline maintenance to prevent discharges from each flowline."

Florida requires facilities to submit a plan of flowline installation and construction as well as a map and design specifications. Florida also requires a contingency plan for flowlines that should include basic information, a map, and information about hydrogen sulfide concentrations. Michigan requires that a contingency plan with general information, a map, and available data on hydrogen sulfide concentrations be submitted.

Few other states have any requirements for a flowline "program." California requires "pipeline management plan" for pipes that are located in environmentally-sensitive areas. Colorado provides many requirements for flowlines and pipelines, for the purpose of preventing discharge, but does not require a maintenance program. Colorado lists requirements underneath "Installation and Reclamation" for flowline construction material, design, cover, excavation, backfill, and reclamation, and pressure testing. The next section, entitled "Operations, Maintence, and Repair," describes provisions for flowline maintenance, repair, and marking (to identify the location of flowlines.) The final section, "Abandonment," describes what is needed to be done when abandoning a flowline.

The Arkansas Oil and Gas Commission rules require that "All flowlines used in the production of liquid hydrocarbons, constructed after the effective date of this rule, shall be buried at least twenty-four (24) inches below the ground surface." Louisiana and Texas require that natural gas pipelines be designed, constructed, maintained, and operated in accordance with several Department of Transportation regulations, but does not mention *oil* pipelines or flowlines.

We were unable to find information on specific flowline requirements for the following states: AK, AL, AZ, IL, IN, MO, MS, MT, ND, NE, NM, NV, NY, OH, PA, SD, TN, UT, VA, WY.

Table 1, below, provides a summary of how state requirements compare to the 20 SPCC provisions described above. This comparison is provided, for each state and SPCC provision, based on a score between 1 to 3, with the highest score used for state requirements that seemed similar in scope and specificity to the spill prevention measures required under the SPCC rule for the cited provision, Scores of ‘0’ are used in cases where we were unable to find a state requirement corresponding to the SPCC requirement.

As shown in the table, some states have spill prevention requirements that are similar to SPCC requirements. None of the states we reviewed, however, have programs that comprehensively address all of the selected SPCC measures.[7]

[7] One state, Ohio, had been working as recently as 2006 on developing its own SPCC program for oil production facilities that would include elements similar to EPA’s SPCC rule. The status of that effort is unknown.

Table 1: Similarities with SPCC Requirements

SPCC Requirement	AL	AK	AZ	AR	CA	CO	FL	IL	IN	KS	KY	LA	MI	MS	MO	MT	ND	NE	NV	NM	NY	OH	PA	OK	SD	TN	TX	UT	VA	WV	WY
§112.3	1	0	0	0	2	1	3	0	0	2	3	2	1	1	0	0	3	0	0	2	1	3	1	2	1	0	0	1	2	0	0
§112.3(d)	0	0	0	0	0	0	0	0	0	0	3	0	1	0	0	0	0	0	0	2	0	0	0	3	0	0	0	0	0	0	0
§112.4	3	2	3	2	0	2	0	2	2	0	0	0	1	2	0	2	0	1	1	3	3	0	1	1	1	0	2	3	2	3	0
§112.5	0	1	0	0	0	0	2	0	0	0	0	3	0	0	0	0	3	0	0	3	3	3	0	0	0	0	0	0	0	0	0
§112.7(b)	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0
§112.7(c)	2	0	1	3	3	3	2	0	3	3	3	2	2	0	0	0	3	1	1	3	0	2	3	1	0	2	2	1	3	3	3
§112.7(d)	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	3	0	0	2	0	0	0	0	0	0	0	0
§112.7(e)	0	3	3	0	0	2	0	0	0	3	3	3	0	2	0	0	0	0	0	0	0	0	1	1	3	0	3	0	3	0	0
§112.7(f)	0	0	0	0	0	1	0	0	0	0	2	0	0	2	0	0	3	0	0	0	0	1	0	1	0	2	0	1	1	0	0
§112.7(i)	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
§112.7(j)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	2	0	0	0	0	0	0	0	0	0
§112.7(k)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
§112.9(b)	2	0	0	2	1	0	2	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	2	0	2	0	0	0	3	0
§112.9(c)(1)	0	1	0	0	1	3	3	0	0	0	2	2	1	0	0	0	0	0	0	3	0	0	0	2	2	0	0	1	0	3	0
§112.9(c)(2)	3	0	2	3	2	0	3	3	0	0	3	3	3	3	0	2	0	3	0	3	2	0	0	1	3	2	2	0	3	3	0
§112.9(c)(3)	2	1	0	0	0	1	2	1	0	0	0	1	0	2	0	0	0	0	0	3	0	0	0	0	0	0	0	0	2	3	0
§112.9(c)(4)	0	0	1	1	1	0	3	0	1	0	0	2	2	0	0	0	0	0	0	2	0	0	0	0	0	2	1	0	0	3	0
§112.9(d)(1)	1	1	2	0	2	2	2	0	2	0	0	2	2	2	0	1	0	0	0	3	0	0	0	0	0	0	0	0	2	3	0
§112.9(d)(2)	0	0	0	2	0	0	1	0	0	1	0	0	0	0	0	0	2	0	1	3	0	0	3	1	0	0	2	0	0	3	2
§112.9(d)(3)	0	0	0	2	3	1	3	0	0	1	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	0	3	0

Key:

3: State requirement is similarly stringent as SPCC requirement

2: State has requirement that covers a subset of SPCC requirement (e.g. some, but not all, equipment).

1: State mentions equipment/facility component but does not have specific requirement other than general duty to prevent discharges.

0: No corresponding requirement found.

4. National Pollutant Elimination System (NPDES)

4.1 Overview of NPDES Program

The Clean Water Act (CWA) requires that all point source discharges of pollutants to surface waters be authorized by a permit issued under the NPDES program. Permit requirements apply to facilities, such as manufacturing plants or publicly-owned wastewater treatment plants, which discharge process effluent or wastewater to surface waters either directly or via a publicly-owned wastewater treatment plant. Permits are also required for stormwater discharges that contain pollutants from runoff of precipitation over land and impervious areas within a permitted facility.

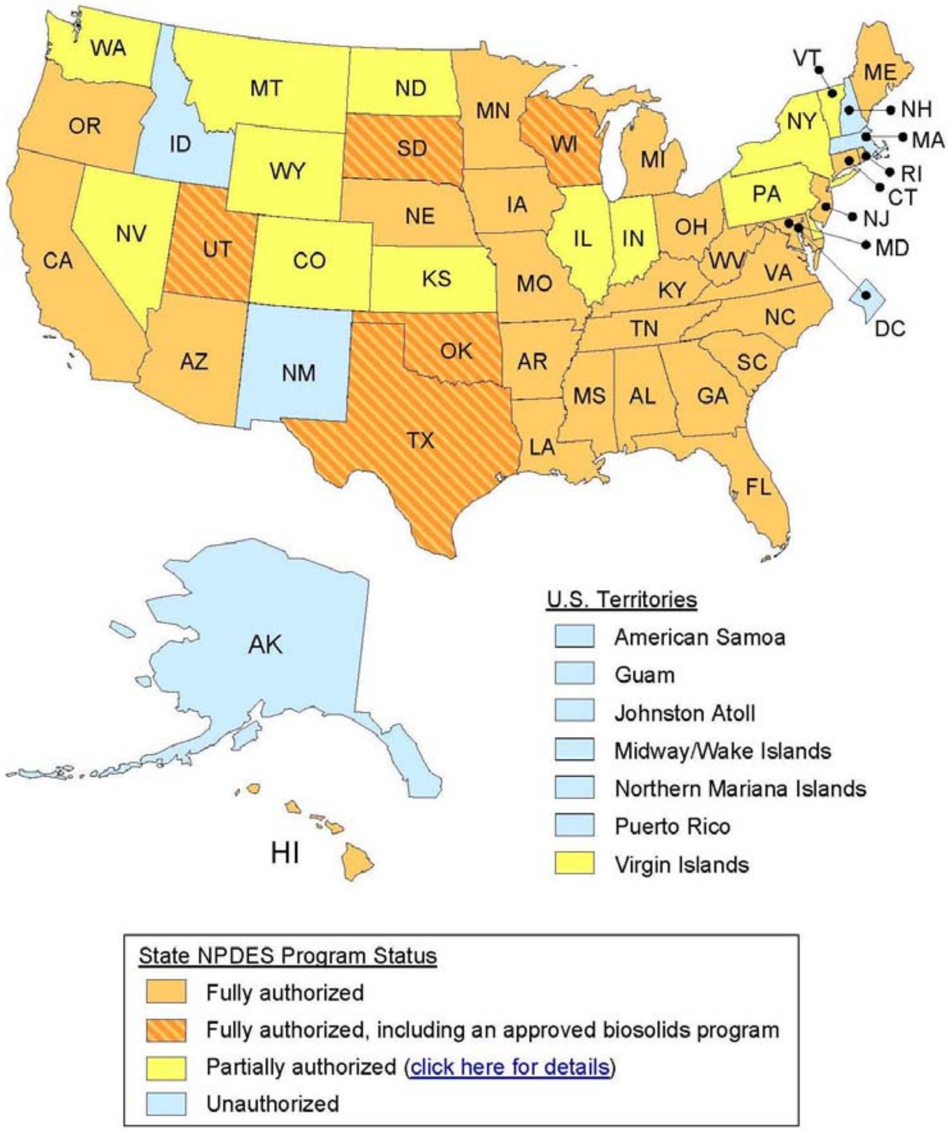
NPDES permits have five general provisions:

- *Technology-based limitations*. All point source dischargers must comply with technology-based limitations which rely on the ability of technology to reduce the amounts of pollutants discharged to water. As part of its Effluent Guideline Program Plan, EPA routinely reviews process and treatment technologies for selected industries to determine if federal technology-based effluent limits need to be promulgated. If so, EPA establishes such minimum standards on an industry-by-industry basis. Generally, NPDES permittees are not required to implement a specific pollution control technology. Rather, they may implement a technology of their choosing, as long as effluent limits specified in their permit are met.
- *Water quality based limitation*. Water quality based limitations are used when technology-based limitations are not sufficient to meet state ambient water quality standards.
- *Monitoring and reporting requirements*. Permittees are required to monitor their discharges and report the results. The NPDES permit outlines the pollutant parameters that must be sampled, locations where samples must be collected, the frequency and method of sampling, the analysis techniques, and the frequency of reporting.
- *Standard conditions*. Standard conditions include, among others, an express duty to minimize or prevent any permit violation that has a reasonable likelihood of adversely affecting human health or the environment and a duty to properly operate and maintain the facility and its treatment equipment at all times.
- *Special conditions*. Special conditions are specified considering site-specific conditions. For stormwater discharge permits, these special conditions typically include the development and implementation of a facility-specific Stormwater Pollution Prevention Plan (SWPPP).

4.2 Authorization of State NPDES Programs

EPA published federal NPDES regulations under the CWA, and may authorize states—as well as Territories and Tribes—to implement all or parts of the national program. These regulations differ from the SPCC program, which cannot be delegated to the states even though it is a CWA program. Permitting procedures under state programs are generally similar to those under the EPA-implemented program. To become a permitting authority, EPA regulations require that state programs cover mandated elements and be at least as stringent as the EPA regulations. Once approved, a state gains the authority to issue NPDES permits and administer the program. However, the EPA retains the opportunity to review the permits issued by the state, and formally object to elements deemed in conflict with federal requirements. To date, most states are authorized to administer and implement the NPDES program (i.e., issue permits). As shown on the map in Exhibit 4-1, all oil producing states except for Alaska and New Mexico administer their own NPDES permitting procedures.[8]

Exhibit 4-1. State authorization status under NPDES program.



Source: http://www.epa.gov/npdes/images/State_NPDES_Prog_Auth.pdf. Note that Texas and Oklahoma are not authorized to administer the NPDES program for oil and gas activities. In these two instances, EPA Region 6 is still the permitting authority.

[8] EPA information suggests that the Agency retains authority for certain oil and gas related activities in Texas and Oklahoma that are not on Indian lands.

4.3 Types of NPDES Permits

Two basic types of permits are issued under the NPDES program: individual and general permits.

- **Individual NPDES permits** are specifically tailored to individual facilities. Permit writers consider technology-based effluent limits (“effluent limitation guidelines”) and water quality-based effluent limits, and establish the permit limits based on the more stringent of the two approaches. In the absence of applicable national effluent limitation guidelines, permit writer must use Best Professional Judgment (BPJ) to identify technology-based limitations on a case-by-case basis. The available data show few onshore oil production facilities with individual permits for either wastewater or stormwater discharges.[9]
- **General NPDES permits** cover multiple facilities within a certain category having the same type of discharge and located in a specific geographical area. A general permit applies the same or similar conditions to all dischargers covered. Once EPA or a state has issued a general permit for a category of facilities, a facility wishing to be covered under the permit submits a Notice of Intent (NOI) to the permitting authority who reviews the NOI and determines whether coverage of the facility under the general permit is appropriate, and if not, requires that the facility submit an application for an individual NPDES permit.

A number of authorized states have established general permits that specifically cover onshore oil and gas production operations. Certain authorized states have established state-specific general permits for wastewater from oil and gas facilities, generally limited to facilities located in specific coastal or offshore areas (Section 4.4). General permits also exist for stormwater discharges from oil production facilities, as exemplified by Montana’s general permit described in Section 4.5.1). These state requirements follow the EPA’s Multi-Sector General Permit (MSGP) for Industrial Activities applicable to facilities located in areas where EPA retains the NPDES permitting authority (see Section 4.5.2 for a description of EPA’s MSGP requirements).

4.4 Permits Required for Process Water Discharges

4.4.1 Oil and Gas Extraction Effluent Limitation Guidelines

Certain oil and gas facilities are covered under Category I: Facilities with Effluent Limitations.

EPA established Effluent Limitation Guidelines (ELGs) for the Oil and Gas Extraction point source category on 13 April 1979 (44 FR 22075). EPA imposed a *zero-discharge* requirement for all produced waters in the onshore subcategory (40 CFR 435.32). EPA, however, allowed for two exceptions to the discharge prohibition.

(1) Oil wells with very small production (i.e., stripper wells producing less than 10 bbl/day of oil) are not covered by the Onshore subcategory but are instead regulated under a Stripper subcategory (40 CFR 435.60). While the Agency did not publish standards for this subcategory,

---

[9] A search on EPA’s NPDES website shows 67 individual NPDES permits classified in the Oil and Gas Extraction and Processing category in 19 states (AK, AL, AR, CA, IL, KS, LA, MS, MT, ND, NJ, OH, PA, PR, TX, UT, VA, WI, WY). However, these facilities seem to be refineries rather than oil production facilities.

it left any regulatory controls and direct implementation to the states (where states have authority) or to the regional office.

(2) Oil and gas wells located west of the 98th parallel (roughly the western half of the United States) may be regulated by the effluent limits in the Agricultural and Wildlife Water Use subcategory (40 CFR 435.50) and may be able to discharge produced water if the following conditions are met:

- The produced water must be used in agriculture or wildlife propagation when discharged into navigable waters (40 CFR 435.50); and
- The produced water discharges must not exceed an oil and grease daily maximum limitation of 35 mg/L (40 CFR 435.52(b)).

EPA described “use in agricultural or wildlife propagation” by stating "the produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses, and the produced water is actually put to such use during periods of discharge." (40 CFR 435.51(c)).

EPA established ELGs for oil and gas activities located in certain coastal waters (Cook Inlet, AK) and offshore. For facilities in these two categories, ELGs set oil and grease limits of 29 mg/L monthly average and 42 mg/L daily maximum.

In addition EPA Regions 4, 6, 9 and 10 have issued general permits to facilities discharging into ocean waters beyond the 3-mile limit of territorial seas or certain facilities discharging in the territorial seas.[10]

4.5 Permits Required for Stormwater Discharges

Types of activities generating stormwater discharges and requiring NPDES permits include those in sectors listed under one or more of eleven categories of industrial activity, including Category III: Mineral, Metal, Oil and Gas (i.e., industrial stormwater permit).[11] They also include activities related to construction activities that disturb acreage above a specific threshold (i.e., construction stormwater permit)[12].

Under exemptions contained in CWA Section 402(l)(2), however, no NPDES permit is required for “discharges of stormwater runoff from mining operations or oil and gas exploration, production, processing, or treatment operations or transmission facilities, composed entirely of flows which are from conveyances or systems of conveyances (including but not limited to pipes, conduits, ditches, and channels) used for collecting and conveying precipitation runoff and which are not contaminated by contact with, or do not come into contact with, any

[10] Source: web.ead.anl.gov/dwm/regs/federal/epa/index.cfm

[11] This sector includes activities classified in Standard Industry Classification codes: 1311 (Crude Petroleum and Natural Gas); 1321 (Natural Gas Liquids); and 1381-1389 (Oil and Gas Field Services). Certain construction activities associated with oil and gas sites were once also covered under stormwater category 10: Construction Activity, although EPA has now exempted oil and gas from the Construction Activity Category (71 FR 33628).

[12] EPA established general permits for construction activities that disturb more than 5 acres (NPDES Phase I requirements), and for those that disturb between 1 and 5 acres of land (NPDES Phase II requirements). Construction of most oil and gas production sites falls in that later category (Source: http://www.ipaa.org/issues/comments/Stormwater/Appendix3-DOEAnalysis.pdf).

overburden, raw material, intermediate products, finished product, byproduct, or waste products located on the site of such operations."

Between 1992 and 2006, EPA had interpreted the exemption under section 402(l)(2) as *not* applying to construction activities, and had concluded that permit coverage was therefore required for construction activities at oil and gas sites. In the Energy Policy Act of 2005, however, Congress clarified that activities covered by the oil and gas sector also include "activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities."[13] This change explicitly excludes oil and gas production activities, including construction-related activities associated with preparing an oil and gas lease for eventual operations, from stormwater permitting requirements – except in certain instances when the facility is found to discharge contaminated stormwater. A recent court decision, however, raises questions as to whether EPA will further amend 40 CFR part 122 to reinstate permit coverage for certain oil and gas construction activities.[14]

The oil and gas production exemption extends through the NPDES stormwater discharge program, regardless of whether EPA or a state is the permitting authority. States still have the authority, however, to regulate any discharge, including stormwater discharges from production facilities, pursuant to state law through a *non-NPDES* program. Additionally, oil exploration and production facilities that discharge stormwater **contaminated** with material products from their operations to navigable waters are required to obtain permits under EPA's NPDES program (40 CFR 122.26(b)). Circumstances under which an onshore oil production facility may be required to request a NPDES permit for stormwater discharges include following a reportable discharge or violation of applicable water quality standards.[15] General exemption of the oil and gas sector from stormwater permit requirements, however, suggest that NPDES permits for stormwater discharges are the exception for oil production facilities rather than the rule.

---

[13] CWA Section 502.

[14] On May 23, 2008, the Ninth Circuit Court of Appeals vacated and remanded to EPA the 2006 rule at 71 FR 33628 that had exempted oil and gas construction activities from NPDES permit requirements. EPA is currently in the process of evaluating options for responding to this decision.

[15] EPA noted in answers to frequently asked questions, "storm water discharges from oil and gas activities (i.e., exploration, production, processing, or treatment operations, or transmission facilities, including construction) that are **contaminated by contact with raw material, intermediate products, finished product, byproduct, or waste products,** as indicated by discharges of reportable quantities of hazardous substances or oil, or by violations of water quality standards are subject to NPDES permitting requirements. Note however, that EPA does not consider sediment from construction activities to be the result of such contact and as such, discharges of sediment from construction activities do not trigger the need to obtain permit coverage. Discharges of storm water resulting in the discharge of a reportable quantity or that contribute to a violation of a water quality standard are two criteria for oil and gas activities that meet EPA's "contaminated by contact" threshold for which NPDES permit coverage is required. Once the facility meets either of these two criteria, the operator must obtain NPDES permit coverage under either an individual permit or an applicable general permit. NPDES permit coverage is required for the lifetime of these facilities." (Source: http://www.epa.gov/npdes/regulations/final_rule_QA.pdf, emphasis added)

4.5.1 Example State General Stormwater Permit for Oil and Gas Activities

Montana's general permit (NPDES #MTR300000: Storm Water Discharges Associated with Mining and With Oil and Gas Activities)[16] covers discharge to surface waters of Montana. It covers oil and gas exploration, production, processing, or treatment operations in which stormwater could come in contact with products located on the operational site. The permit only covers discharges of stormwater associated with precipitation; it does not cover process wastewater. All discharges must meet water quality standards. The permittee must control stormwater discharges through implementation of a Storm Water Pollution Prevention Plan. Practices defined within the SWPPP must eliminate or minimize the discharge of pollutants to surface waters.

Key conditions of the general permit include:

- **Discharge Monitoring**. Facilities must perform sampling, testing and reporting of stormwater discharges, including, for oil and gas facilities, semiannual testing of total suspended solids, chemical oxygen demand, pH, flow, and oil and grease. Reporting requirements may be suspended if the facility demonstrates implementation of Best Management Practices (BMPs) to minimize the potential discharge of pollutants, test results have not exceeded EPA benchmark values, and the facility has had no permit violation and no spill or release.

- **SWPPP conditions.** The SWPPP must follow good engineering practices, be maintained at the facility and available upon request, and be amended whenever there is a change in design, construction, operation, or maintenance. SWPPP requirements include:

    - Identifying specific individual and members of pollution prevention team responsible for developing and implementing the SWPPP.
    - Describing potential pollutant sources. Include drainage details, direction of flow and type of pollutants that may be present in the stormwater discharge, and the name of receiving waters.
    - Including inventory of material handled at the site that could be exposed to precipitation and describing existing structural or nonstructural control measures to reduce pollutants in stormwater runoffs.
    - Listing spills and leaks of toxic pollutants or hazardous substances that occurred in areas exposed to precipitation or that otherwise drain to a storm water conveyance at the facility after the date of *three years prior* to the effective date of this permit.
    - Including a narrative description of the potential pollutant sources from the following activities: loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; significant dust or particulate generating processes; and onsite waste disposal practices.
    - Describing stormwater BMPs, including, at a minimum: good housekeeping; preventive maintenance including timely inspection of stormwater management devices such as the cleaning of oil/water separators and catch basins and inspecting and testing facility equipment and systems to uncover conditions that could cause breakdowns or failures that could result in discharges of pollutants to surface waters; spill prevention and response procedures, including procedures and equipment for

[16] See http://www.epa.gov/npdescan/MTR300000GFP.pdf

cleaning up spills and emergency contacts and notification numbers; inspections, specifically inspections of designated equipment and areas of the facility at appropriate intervals (e.g., after 0.5 inch of precipitation); employee training; recordkeeping procedures; sediment and erosion control; and management of runoff.

- Performing a comprehensive site compliance evaluation at least once a year. This includes visual inspection by qualified personnel of equipment needed to implement the SWPPP. Outcome of the inspection must be documented and findings addressed in the SWPPP.
- Certifying (and responsible individual signing) that only stormwater will be discharged under the Permit and that all information is true and correct. Any non-stormwater discharge is a violation of the permit.

The general permit also sets compliance conditions, including duty to comply; penalties for permit violations (e.g., up to $25,000/$50,000 per day for first/subsequent violations); duty to prevent or mitigate discharges; proper operation and maintenance; and proper disposal of removed substances.

Finally, the General Permit sets general requirements such as a notice of planned physical facility alterations; permit modifications, duty to provide information; signature requirements, transfers, etc.

Data are not publicly available from the Montana Department of Environmental Quality to determine how many onshore oil production facilities currently have an NPDES for stormwater discharge under the industrial category. Our review of data available for a similar program in California, however, identified only 35 onshore oil production facilities covered under the industrial sector category, or only a small fraction of the estimated number of oil production facilities.[17]

Overall, the measures implemented through the NPDES program are broad in scope, and often not as stringent as those required under the SPCC regulation. The purpose of NPDES permits, is to treat and manage foreseeable and chronic point discharges as may occur under normal operations rather than accidental releases, and the measures therefore implemented as part of a NPDES and SWPPP do not adequately address the circumstances addressed by an SPCC Plan.

4.5.2 EPA Industrial Facility Multi-Sector General Permit (MSGP)

EPA issues a multi-sector general permit that applies to industrial facilities located within EPA's NPDES authority (where the states are not authorized), including certain oil and gas production facilities. Permit conditions common to all industrial activities covered under the MSGP are generally similar to the permit conditions described for Montana's general permit described in Section 4.5.1. They include:

- Notification requirements. (NOI)

[17] Based on California Water Board database of active stormwater permits classified in SIC code 1311: Crude Petroleum & Natural Gas.

- “Special Conditions”, which include prohibition of non stormwater discharges, general duty to eliminate or mitigate releases of reportable quantities of hazardous substances and oil in accordance with SWPPP developed for the facility, and numeric effluent limitations.
- “Common SWPPP Requirements”, which, outline the contents of the facility SWPPP, including the identification of a pollution prevention team, the description of facility and potential pollution sources, and the selection and implementation of stormwater controls. These controls must include, subject to consideration of economic feasibility and effectiveness: structural controls and nonstructural controls**.** Examples of nonstructural controls include: good housekeeping, minimizing exposure of potential pollutant sources to stormwater, preventive maintenance program that involves regular inspection and maintenance of stormwater management devices and other equipment and systems, spill prevention and response procedures (including appropriate material handling procedures, storage requirements, containment or diversion equipment, and spill cleanup procedures to minimize the potential of a spill and, in the event of a spill, enable proper and timely response), and routine inspections (performed by qualified personnel and recorded). Examples of structural controls include sediment and erosion control, management of runoff, and other controls to prevent the discharge of solid materials, dust emissions, etc.

4.6 Comparison of NPDES and SPCC Requirements

As confirmed by the Office of Water staff,[18] the NPDES program permits and controls regular discharges, not upsets or bypass events. NPDES stormwater discharge permits often include spill prevention measures to address spills that may be exposed to precipitation and discharged through precipitation runoff. While these spill control requirements are at times similar to the types of measures envisioned by the SPCC regulation, they are not necessarily as stringent and/or as specific as federal SPCC requirements. In addition, while many NPDES stormwater discharge permits include spill control requirements, the NPDES regulations do not require that such measures be included in permits and as such, there is no minimum set of requirements that must be included in every NPDES stormwater permit. Furthermore, NPDES stormwater permits are often only required at onshore oil production facilities if there is a demonstrated potential for stormwater contamination runoff, for example, following violation of water quality standards or a reportable discharge under 40 CFR part 110.

In contrast to the SPCC rule which is concerned with preventing all oil discharges to waters, including accidental releases of produced water as those that may result from container failures, the NPDES program only focuses on those measures that would help mitigate discharges associated with stormwater runoff or pre-determined wastewater discharges meeting the effluent limits set by the permit.

In short, NPDES permit requirements are generally not in effect at oil and gas production facilities unless specifically required by the state for all oil and gas production sites, or if the facility has experienced a discharge thereby demonstrating the potential for contaminated stormwater discharges.

[18] Discussions between Abt Associates and OW staff in June 2008.

In cases where an onshore oil production facility does have a stormwater discharge permit under the NPDES program, some of the measures implemented as part of a stringent, highly protective permit could, either directly or indirectly, also mitigate the damage that would be caused by an uncontrolled release of production fluids from oil handling and storage areas or equipment. However, NPDES regulations do not specifically require development and implementation of spill control measures, thus requirements vary widely between NPDES permits. Also, NPDES stormwater permits typically provide a general framework for spill control measures but details of site-specific practices are contained in the site-specific SWPPP and can vary widely. Since facility owners/operators describe specific measures in the SWPPP to meet spill control requirements in the permit, it is difficult to make generalizations on how measures implemented under NPDES compare to SPCC-required measures.

For example, the SPCC rule specifically requires that sized secondary containment be provided around oil storage areas, e.g., tank batteries, to contain the capacity of the largest tank plus sufficient freeboard for precipitation. In contrast, the NPDES program typically requires structural control measures that manage potentially contaminated stormwater runoff. These structural control measures may be, but are not necessarily, dikes, berms, or other measures that are required under SPCC. That said, at least one state – Alabama – refers specifically to SPCC secondary containment requirements in its guidance to NPDES permit holders in the industrial stormwater category. Alabama recommends that containment dikes at NPDES-permitted industrial facilities contain at least 110 percent of the capacity of the largest tank located within the dike; the requirement is not limited to oil containers but applies to tanks holding any pollutant that could potentially escape.[19]

Regarding inspections, the SPCC rule contains specific requirements to "periodically and upon a regular schedule visually inspect each [bulk storage] container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground." (§112.9(c)(3).) NPDES permit conditions mention equipment inspections, but mostly focused on equipment associated with drainage controls, including a requirement for an annual evaluation of the effectiveness of stormwater control measures.

Compliance with required SPCC measures would likely help implement a SWPPP to comply with NPDES permit requirements. However, given the flexibility allowed in the scope and content of a NPDES stormwater permits and documented in the SWPPP, the converse is not necessarily true (i.e., SWPPP measures do not necessarily meet the SPCC requirements).

5. Requirements under Underground Injection Control (UIC) Programs

In 1980, EPA promulgated the UIC regulations which are designed to protect underground sources of drinking water. The UIC program applies to different classes of injection wells, with oil field injection wells designated at Class II injection wells.

Class II wells inject fluids associated with oil and natural gas production. Most of the injected fluid is salt water (brine), which is brought to the surface in the process of producing (extracting)

---

[19] http://www.adem.state.al.us/waterdivision/Industrial/NPDES/Forms/spccguid.doc. The guidance also provides additional suggested engineering and best management practices for containment areas and transfers that draw on SPCC requirements regarding the design of containers, overfill prevention measures, regular examination of valves and pipelines, etc.

oil and gas. In addition, brine and other fluids are injected to enhance (improve) oil and gas production. According to EPA, the approximately 144,000 Class II wells in operation in the United States inject over 2 billion gallons of brine every day.[20] Most oil and gas injection wells are in Texas, California, Oklahoma, and Kansas.

Three types of Class II injection wells are associated with oil and natural gas production. They include:

- *Enhanced Recovery Wells*, which inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and—in some limited applications—natural gas. This is also known as secondary or tertiary recovery. The injected fluid thins (decreases the viscosity) or displaces small amounts of extractable oil and gas, which is then available for recovery. In a typical configuration, a single injection well is surrounded by multiple production wells. Production wells bring oil and gas to the surface; **the UIC Program does not regulate production wells**. Enhanced recovery wells are the most numerous type of Class II wells, representing as much as 80 percent of all Class II wells. Enhanced oil and gas recovery wells may either be issued permits or be authorized by rule.
- *Disposal Wells* inject brines and other fluids associated with the production of oil and natural gas or natural gas storage operations. Class II disposal wells can only be used to dispose of fluids associated with oil and gas production. Disposal wells represent about 20 percent of Class II wells. Disposal wells are issued permits. The owners or operators of the wells must meet all applicable requirements, including strict construction and conversion standards and regular testing and inspection.
- *Hydrocarbon Storage Wells* inject liquid hydrocarbons in underground formations (such as salt caverns) where they are stored, generally, as part of the U.S. Strategic Petroleum Reserve. There are over 100 liquid hydrocarbon storage wells in operation.

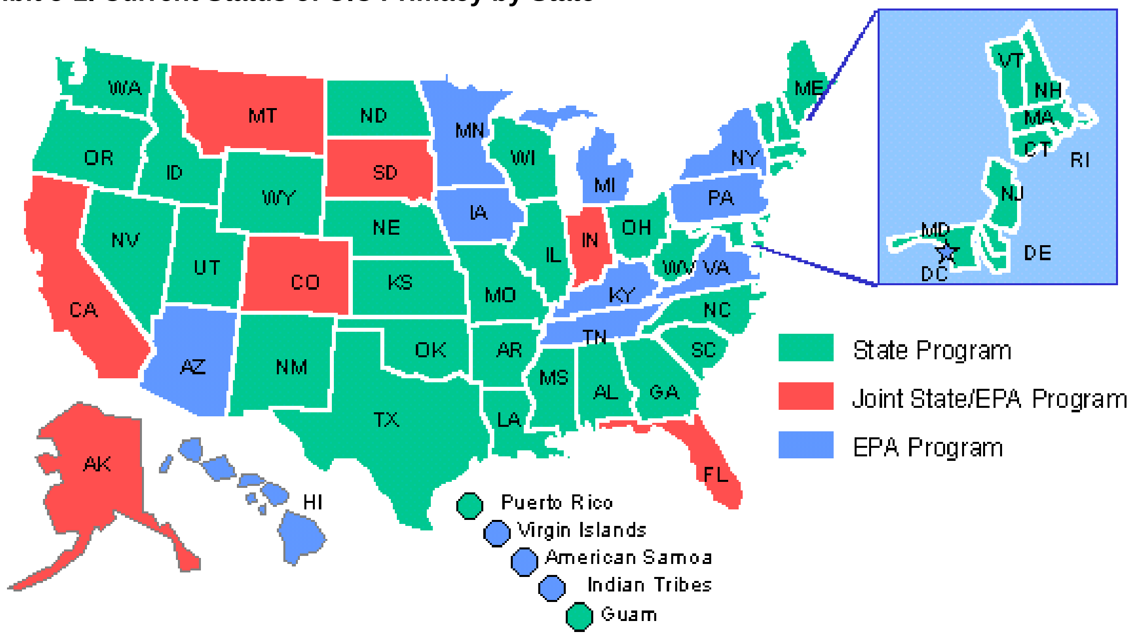
Similarly to the NPDES programs, UIC program implementation may be delegated to the states. EPA has established minimum standards that state programs must meet before a state can be granted “primacy” for UIC under section 1422 of the Safe Drinking Water Act (SDWA).[21] These minimum standards cover various elements, including construction, operating, monitoring and testing, reporting, and closure requirements for well owners or operators.

Exhibit 5-1 identifies states for which EPA has delegated UIC primary for all well classes (in green). In some cases (shown in red on the figure), states share responsibility of UIC requirements with EPA (i.e., EPA has authority over some classes of wells and the state has authority for others).

[20] http://www.epa.gov/SAFEWATER/uic/wells_class2.html

[21] As an alternative to UIC programs, Section 1425 allows states to demonstrate that their existing standards are effective to protect underground drinking water.

Exhibit 5-1. Current Status of UIC Primacy by State[22]



Source: http://www.epa.gov/SAFEWATER/uic/primacy.html#who

Most of the states we reviewed have UIC programs, although some of the states refer back to federal rules for specific requirements. Pennsylvania and Kansas permits underground injection operations in conjunction with the EPA's UIC permit requirements at 40 CFR 146. Oklahoma adheres to the federal UIC permitting requirements written in Title 40 CFR Parts 124. Arkansas also has many inspection requirements for underground injection wells, such as bi-monthly inspections by ADEQ and daily well inspections. In applying for UIC permits, operators must generally demonstrate that the proposed disposal will not allow the movement of oil field wastes into sources of freshwater.

As confirmed by the EPA UIC program staff, across UIC programs, however, substantive requirements tend to focus on the design or operation of the well (e.g., casing integrity, pressure control and monitoring), rather than surface equipment that may be associated with the injection process.[23] The UIC requirements are therefore not directly comparable to SPCC provisions in terms of preventing discharges to navigable waters or adjoining shorelines from oil containers or other parts of a facility where oil is stored, transferred, or handled.

[22] See http://www.epa.gov/safewater/uic/primacy.html

[23] Discussion with UIC staff at EPA Headquarters confirms that the program is mostly concerned with the injection wells (i.e., downhole conditions) and not surface equipment. UIC staff noted that the program may issue violations for "pipeline severances" in cases where the piping leading to the injection well is severed, but the program does not have specific testing or maintenance requirements for that piping, or for other surface equipment found at the injection facility. (Personal communication with Robert Smith, 03/11/2008)

6. Definitions of Marginal or Stripper Well

The SPCC rule does not define the terms marginal well or stripper well. However, under the NPDES regulations for Oil and Gas Extraction Point Source Category, EPA has defined a stripper subcategory as onshore facilities which produce 10 barrels per well per calendar day or less of crude oil and which are operating at the maximum feasible rate of production and in accordance with recognized conservation practices (40 CFR 435.60). These terms are also defined in some state regulations associated with oil production, or incorporated as separate categories in state's schedules for severance tax or royalty fee for oil production.

Kentucky, New Mexico, Montana, Tennessee and Wyoming define a stripper well as a well that produced an average of less than 10 barrels daily output during the preceding calendar year. Utah defines the stripper well using the average of 20 barrels or less.

North Dakota defines a stripper well both in terms of average daily production and depth. Thus, North Dakota considers as "stripper well" a well that produces an average of 10 barrels per day or less if shallower than 6,000 feet. North Dakota also defines a stripper well as one with a depth of 6,000 to 10,000 feet and with an average daily production of less than 15 barrels, or a well with a depth of 10,000 feet or more with an average daily production of less than 30 barrels.

Texas also defines marginal wells using a combination of production rate and depth. Texas defines marginal well as a well that can only reach capacity using pumping, gas lift, or other artificial lift, with a depth of 2,000 feet or less and an average maximum daily capacity of 10 barrels or less; a depth of 2,000 to 4,000 feet with an average maximum daily capacity of 20 barrels or less; a depth of 4,000 to 6,000 feet with an average maximum daily capacity of 25 barrels or less; a depth of 6,000 to 8,000 feet with an average maximum daily capacity of 30 barrels or less; a depth of 8,000 feet or more with an average maximum daily capacity of 35 barrels or less.

Mississippi defines marginal well using the same production threshold as Utah (20 barrels per day), but limits the depth to 7,500 feet or less. Wells deeper than 7,500 feet are also considered marginal if they produce a monthly average of forty (40) barrels of oil a day or less.

We could not find state-specific definitions of marginal or stripper wells for the following states: AL, AK, AZ, AR, CA, CO, FL, IL, IN, KS, MI, MO, NE, NV, NY, OH, OK, PA, SD, VA and WV .

7. Oil Severance Taxes or Royalty Fees

According to the Department of Energy's (DOE) Energy Information Administration, most States impose a severance tax when oil (or gas or another natural resource) is produced from property within their territory.[24] It is generally a percentage of the sale price and thus state revenue from oil production vary with the market price of crude oil. For Alaska, the State by far the most dependent on oil production activity, severance taxes account for about half of all State tax revenue. In other large producing States, severance tax revenue is a significant but smaller fraction of total tax revenue, generally less than 10 percent.

[24] Department of Energy, Energy Information Administration, http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/price_taxes.htm

Royalty fees are paid to public or private landowners and are part of a standard contract to produce oil or gas from a given property. The amount of the royalty percentage is part of the negotiation process and thus varies with boom and bust cycles in the industry. According to DOE, oil royalties are generally about 1/7 (14 percent) of the sale price. Royalty agreements with the Federal government have generally specified a higher royalty payment.

We obtained only preliminary information on severance taxes or royalty fees for the majority of the 31 states reviewed in this memo, as this information seems less readily accessible in the publicly accessible records.

In some cases we reviewed, the states set varying rates for different types of oil operations. For example, Louisiana sets at 12.5 percent of the oil value the default severance tax rate.[25] Lower rates are specified for certain wells (incapable wells which produce more than 25 barrels per day and also produce at least 50 percent saltwater per day; stripper wells which produce an average of 10 barrels per day). Louisiana also has a special rate for reclaimed oil, set at 3.125 percent of the oil value received for the first purchase (this is oil recovered at reclamation facilities permitted by LA Office of Conservation). This point demonstrates that regulators have identified that a significant amount of oil is found in produced water and as a result tax the oil recovered from produced water at produced water treatment facilities. It further supports EPA's assertion that produce water after primary separation can contain significant amounts of oil. Qualified tertiary recovery projects are exempt from severance tax until they have reached payout. Additionally, severance tax is suspended for stripper wells when the average price of oil drops below $20 per barrel. Other incentives and exceptions are also provided.

Nebraska also levies different tax rates on different well types. In Nebraska, the severance tax is levied at the rate of three percent of the value of non-stripper oil and natural gas severed from the soil of this state.[26] Stripper wells producing oil shall remit severance tax at the rate of two percent. The tax is paid by the first purchaser if the oil or natural gas is sold in Nebraska, or by the person doing the severing if the oil or natural gas is sold outside Nebraska.

In South Dakota, the taxable value of petroleum is the posted field price per unit at the point of production, less any rental or royalty payment belonging to the United States or the State of South Dakota or its political subdivisions. In Virginia, counties and cities are authorized to levy severance tax on oil at a rate equal to one-half of one percent of the gross receipts from the sale of oil severed in the given county or city. In West Virginia, severance tax is five percent of the gross value of the natural gas or oil produced, as shown by the gross proceeds derived from the sale. In Tennessee, severance tax on crude oil is three percent of its sale price. In Utah, the fee for oil and gas that is produced, saved, sold or transported is 0.002 times the value of oil or gas.

8. Conclusion

The review of requirements applicable to onshore oil production facilities under state environmental regulations and NPDES and UIC programs shows that these requirements, while they may be complementary, may not be considered equivalent to the SPCC program.

[25] Louisiana Department of Natural Resources, http://dnr.louisiana.gov/sec/execdiv/techasmt/facts_figures/la_severance_tax_2007_2008.pdf

[26] No definition of "stripper well" could be found in the Nebraska's environmental regulation.

In general, oil producing states have spill prevention regulations that specifically cover oil production facilities, but these regulations vary significantly from state to state. While state regulations may be more stringent on certain elements, their overall scope is often different from that covered by SPCC. State requirements are generally less specific with regard to spill prevention measures associated with the storage or handling of oil and oil mixtures than SPCC provisions.

Looking at state regulations, Abt Associates found that approximately two-thirds of the 31 states have requirements similar to elements of §112.3, §112.4, 112.7(c) and §112.9(c)(2), regarding requirements for preparation, implementation, and amendment of SPCC Plans, general secondary containment, and sized secondary containment for tank batteries. Requirements that appeared less often and were less stringent or specific when they did appear in approximately one-third of state regulations were those pertaining to drainage control (similar to §112.9(b)), container design (§112.9(c)(1)), periodic visual inspection of containers (§112.9(c)(3)), and overfill prevention measures (§112.9(c)(4)). Most states do not have requirements similar to SPCC general requirements found in §112.7(b), (d), (j) and (k).

The review of federal and state data suggests that the vast majority of onshore oil production facilities do not have, nor require, NPDES permits. In cases where general or individual permits requirement do apply to an oil production facility, the NPDES requirements are not as stringent and/or as specific as SPCC requirements and focus either on structural and non-structural measures that would prevent or mitigate ongoing discharges associated with stormwater runoff or on water quality sampling and reporting to ensure that process effluents meet specified permit limits. Measures implemented as part of a NPDES permit's Stormwater Pollution Prevention Plan may complement, but do not necessarily equate to, measures also required by the SPCC rule, since permittees may choose to implement a variety of measures appropriate to their particular site, considering technical and economic factors.

Most of the 31 oil-producing states have UIC programs, although some of the states refer back to federal rules for specific requirements. The UIC requirements, however, focus on injection wells and do not cover production wells or surface oil production equipment.