FOSSIL ENERGY

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PROTOCOL FOR APPRAISAL OF PETROLEUM PRODUCING PROPERTIES ON NATIVE AMERICAN TRIBAL LANDS

February 1998

April 1999

Performed Under Contract No. DE-AC22-94PC91008
(Original Report Number NIPER/BDM-0347)

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Bartlesville, Oklahoma

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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1.0 INTRODUCTION

Petroleum is currently produced on Native American Tribal Lands and has been produced on some of these lands for approximately 100 years. As these properties are abandoned at a production level that is considered the economic limit by the operator, Native American Tribes are considering this an opportunity to assume operator status to keep the properties producing. In addition to operating properties as they are abandoned, Native American Tribes also are assuming liabilities of the former operator(s) and ownership of equipment left upon abandonment. Often, operations are assumed by Native American Tribes without consideration of the liabilities left by the former operators. The purpose of this report is to provide protocols for the appraisal of petroleum producing properties and analysis of the petroleum resource to be produced after assuming operations. The appraisal protocols provide a spreadsheet for analysis of the producing property and a checklist of items to bring along before entering the property for onsite appraisal of the property. The report will provide examples of some environmental flags that may indicate potential liabilities remaining on the property left unaddressed by previous operators. It provides a starting point for appraisal and analysis of a property with a basis to make the decision to assume operations or to pursue remediation and/or closure of the liabilities of previous operators.

1.1 RESERVOIR ANALYSIS

It is recommended that Native American Tribes that consider assuming operations of petroleum producing properties abandoned by previous operators conduct an analysis of the petroleum resource remaining the reservoir. Production records and well records are commonly maintained by the Bureau of Indian Affairs, Minerals Management Service, the Native American Tribe, or state where the Native American Tribe is located. These records contain well data such as well history, electric log surveys, cores, core analysis, driller's logs, well location, field name, initial production, pay thickness, etc. Additional records are kept on mechanical integrity of all disposal wells and waterflood injection wells, well construction, environmental violations, petroleum production history, water production history, etc.

The reservoir analysis spreadsheet in Appendix A was developed under the Department of Energy's Native American Initiative, Field Laboratory in the Osage Reservation—Determination of Status of Oil and Gas Operations program by BDM-Oklahoma, Inc. at the National Institute for Petroleum and Energy Research (NIPER). Data maintained by one of the agencies in charge of oversight of petroleum production operations of particular Native American Tribes can be entered into the Excel spreadsheet provided with this report. The spreadsheet can be used to analyze reservoirs under consideration for assuming operations, before making a decision to appraise the property. After conducting an analysis of a reservoir, the economics of the project can be determined, and a decision can be made to continue with an appraisal of the property or to stop with no appraisal.

The time to conduct an economic analysis of the lease(s) is after assessing the production potential but before proceeding with the pre-onsite investigation. An economic analysis form and a complete explanation of the form is in Appendix B. Reservoir data and production data collected for the reservoir analysis may be used to conduct an economic analysis. Oil prices, lifting costs, and equipment costs and installation may be available in the lease records of the previous operator, from equipment companies, and from oil purchasers. After conducting an analysis of the reservoir, the economics of the project can be determined, and a decision can be made to continue with an appraisal of the property or stop with no appraisal.

1.2 PRE-ONSITE INSPECTION CHECKLIST

The Pre-Onsite Inspection Checklist is the starting point for producing property appraisal. This set of checklists will allow Native American Tribes to conduct offsite evaluation of properties and make fact-based decisions whether to proceed with an onsite appraisal or require previous operators to remediate problems and settle litigation matters. This checklist is in Appendix C.

1.2.1 Courthouse Records Check

A check of Courthouse records is the starting point for decision making on whether to proceed with an onsite appraisal of producing properties by Native American Tribes. To check Courthouse records, inspectors should note that the Office of the County Clerk is where various types of transactions dealing with land and minerals are recorded and kept. The types of records that an investigator will want to identify and enter into a report for a Tribal Council or Tribal Petroleum Company are lease terms, division orders, and litigation records.

1. The original lease between the operator of record and subsequent operators will be on file in the Office of the County Clerk. An index is kept by the County Clerk with the volume and page where the original lease is recorded. Investigators are allowed to access these records and make copies for a "reasonable" fee. In some instances, the County Clerk may charge a small fee for accessing and reviewing the records on file. Within the lease, the investigator will be able to determine royalty, overriding royalty

interest, net revenue interest, damage obligations, etc. The checklist Lease Terms is located in Appendix C. In some cases, the same records also are recorded by the Native American Tribe, Bureau of Indian Affairs, and/or Minerals Management Service.

2. While an investigator is checking records in the Office of the County Clerk a records check for Division Orders can also be made. A division order is a document that specifies, in writing, the percentage interest of the operator, non-operating partners, Native American Tribe, and overriding royalty interests. In the checklist, the operator and non-operating partners are designated as "working interest" (WI) partners. The checklist for Division Orders is located in Appendix C. In some cases, the same records also are recorded by the Native American Tribe, Bureau of Indian Affairs, and/or Minerals Management Service.

3. While an investigator is checking records in the Office of the County Clerk, a records check for Litigation on the leases can be conducted. Litigation records of current filings, as well as historical cases, will be in these files. The checklist for Litigation Records is located in Appendix C. In some cases, the same records also are recorded by the Native American Tribe, Bureau of Indian Affairs, and/or Minerals Management Service.

1.2.2 Lease Records

Lease Records are commonly kept in offices of Native American Tribes, Bureau of Indian Affairs, and/or Minerals Management Service. The records can be accessed and investigated for well records, production records, reservoir records, environmental records, and equipment records simultaneously with a Courthouse Records check.

1. Historical records for wells drilled on Native American Tribal lands are stored in offices of Native American Tribes, Bureau of Indian Affairs, Minerals Management Service, and/or in the office of lease operators. These records contain data such as drilling records, well construction, logging records, open hole tests, etc. The checklist for Litigation Records is located in Appendix C.

2. Current and historical production records for wells, fields, and/or leases kept on Native American Tribal lands are stored in the offices of Native American Tribes, Bureau of Indian Affairs, Minerals Management Service, and/or in the office of lease operators. These records contain data such as completion records, production records, oil and/or gas sales, produced water, pipelines, tank batteries, location plats, etc. The checklist for Litigation Records is located in Appendix C.

3. Current and historical reservoir records for wells, fields, and/or leases kept on Native American Tribal lands are stored in offices of Native American Tribes, Bureau of Indian Affairs, Minerals Management Service, and/or in the office of lease operators. These records contain data such as coring records, core analysis, petrophysical

properties, reservoir characterization, structure maps, reservoir geology, etc. The checklist for Litigation Records is located in Appendix C.

4. Historical environmental records for wells, fields, and/or leases kept on Native American Tribal lands are stored in offices of Native American Tribes, Bureau of Indian Affairs, and/or Minerals Management Service. These records contain data such as violation records, citation records, fines, mechanical integrity tests (MITs), salt water disposal wells, oil/salt water spills, disposal/waterflood well construction, etc. The checklist for Litigation Records is located in Appendix C.

5. Inventory records of equipment located on petroleum producing leases kept on Native American Tribal lands are stored in offices of Native American Tribes, Bureau of Indian Affairs, Minerals Management Service and/or in the office of lease operators. These records contain data such as an equipment inventory, original and current value of equipment, location map of equipment, condition of equipment, repair/replacement records, storage tanks, oil/water separators, etc. The checklist for Litigation Records is located in Appendix C.

1.2.3 Decision

After a Courthouse Records examination and a Lease Records examination have been completed, a decision can be made to proceed with a site appraisal or stop. This decision will be based on facts learned during the pre-onsite investigation. If there are no litigations, no environmental problems that the Native American Tribe must remediate, equipment is in satisfactory condition, the previous operator has suspended operations in writing, etc., a decision can be made to continue with a site inspection. Problems that can be solved by negotiations with former operators and/or U.S. government agencies may not prevent entry onto abandoned leases to conduct a site appraisal. Severe environmental problems, litigation, "red tagged" equipment, or other liability problems can prevent Native American Tribes from continuing to the next step of Site Inspection. With a satisfactory pre-onsite investigation, the Native American Tribe can continue with the site investigation to verify the surface condition of the lease and condition of the equipment.

1.3 SITE INSPECTION CHECKLIST

With a decision that conditions on the lease are satisfactory and that lease equipment is in satisfactory condition, the site inspection phase can begin. In conducting a site inspection, experienced site inspectors are the preferred personnel for this phase of producing property appraisal. In the event that there are no experienced inspectors on hand, inexperienced inspectors may be used with special attention being paid to making sure that all equipment is on location at the location identified on location maps, all equipment is in satisfactory working condition, there are no leaking lead lines (pipelines), all storage tanks are in good condition (not leaking), there are no sites where oil/salt water spills have not been remediated, there are no other environmental problems, etc. The Site Inspection Checklist is designed for use by an inexperienced inspector or an inspector that is well experienced in producing property site inspection.

1.3.1 Lease Inspection

Under normal circumstances, Native American Tribal inspectors will be conducting an onsite inspection of producing properties where the surface and minerals are owned by the Tribe. In special cases like the Osage Mineral Estate located in Osage County, Oklahoma, the Estate has maintained ownership of the minerals, but the surface for most of the county has been severed from the minerals in the past. In the case of Osage County, Oklahoma, inspectors have the right of entry onto the producing property, but it may be helpful to notify surface owners if a prolonged investigation is to be conducted. Inspectors should take their time and conduct a thorough inspection. The checklist provided in Appendix C is designed to guide inspectors through an investigation of producing properties. Inspectors can conduct an equipment survey and environmental investigation of producing properties simultaneously in order to shorten the examination time and continue producing petroleum from the properties.

1. The equipment checklist is in Appendix C. Supplied with the equipment inventory from the pre-onsite investigation and the equipment checklist from Appendix C, an investigator will proceed quickly and easily through an onsite inspection to determine the condition and value of the equipment remaining on the property. The examination will determine the condition and value of engines, pumping units shown in Figure 1, engines shown in Figure 2, separators shown in Figure 3, tank batteries shown in Figure 4, tubular goods, injection/disposal wells, pipelines, etc.
2. An environmental examination of a petroleum producing property is an important part of the decision-making process after onsite inspection. An environmental checklist may be found in Appendix D. Environmental regulations affecting hydrocarbon production, exploration, and drilling are contained in Appendix E. The regulations in Appendix E are federal, and all oil and gas operators with producing leases are required by law to comply with these regulations. Some Native American Tribes may have their own set of regulations for petroleum producing operators that are as stringent as federal regulations or even more stringent. Native American Tribes may gain primacy for regulating environmental concerns on their lands by adopting regulations that are at least as stringent as federal regulations. Examples of some of the things to check for in an environmental examination on a lease will be discussed in the next section.

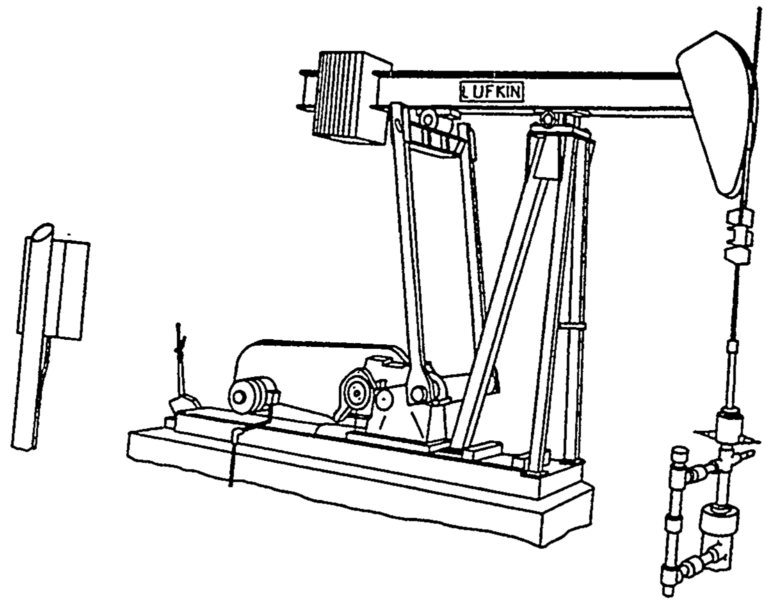

Figure 1 Typical oil-well pumping installation, showing arrangement of oil-well-pumping motor, controller, and capacitor at well location

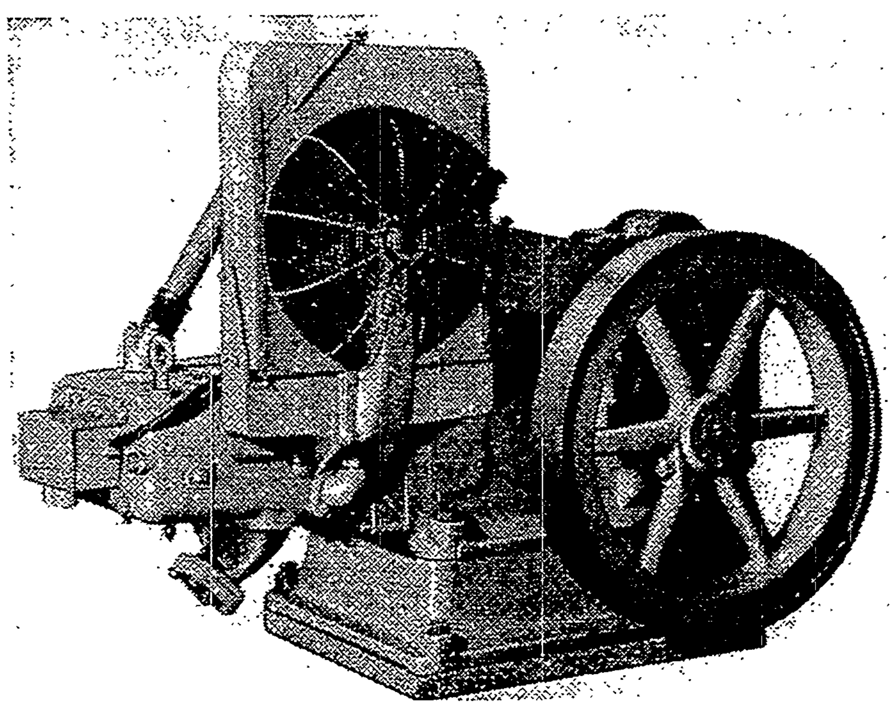

Figure 2 Slow-speed two cycle engine, showing large flywheel

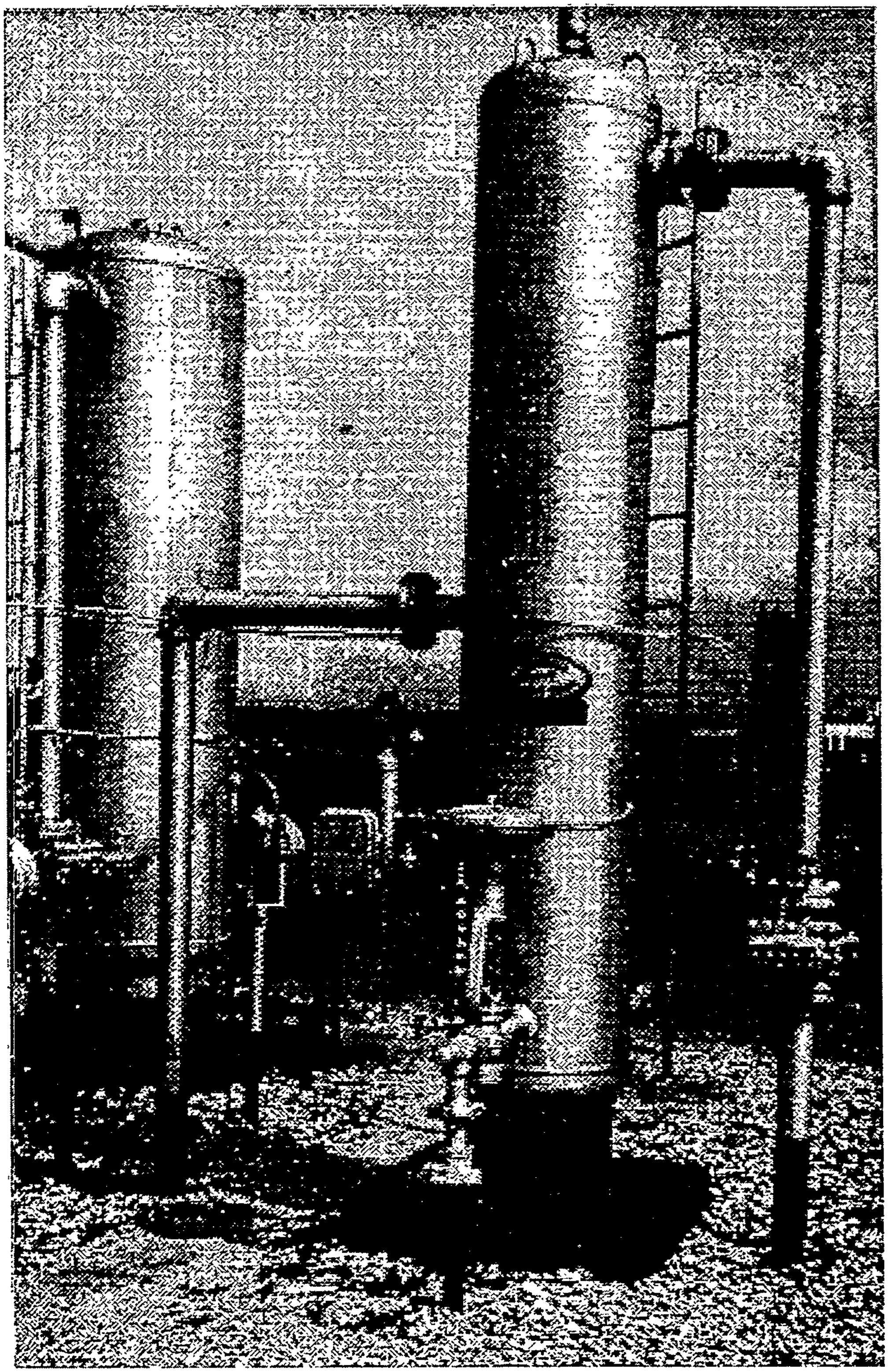

Figure 3 Typical field installation of a vertical two-phase oil and gas separator. (Courtesy of Oil Metering and Processing Equipment Corp., Houston, Texas.)

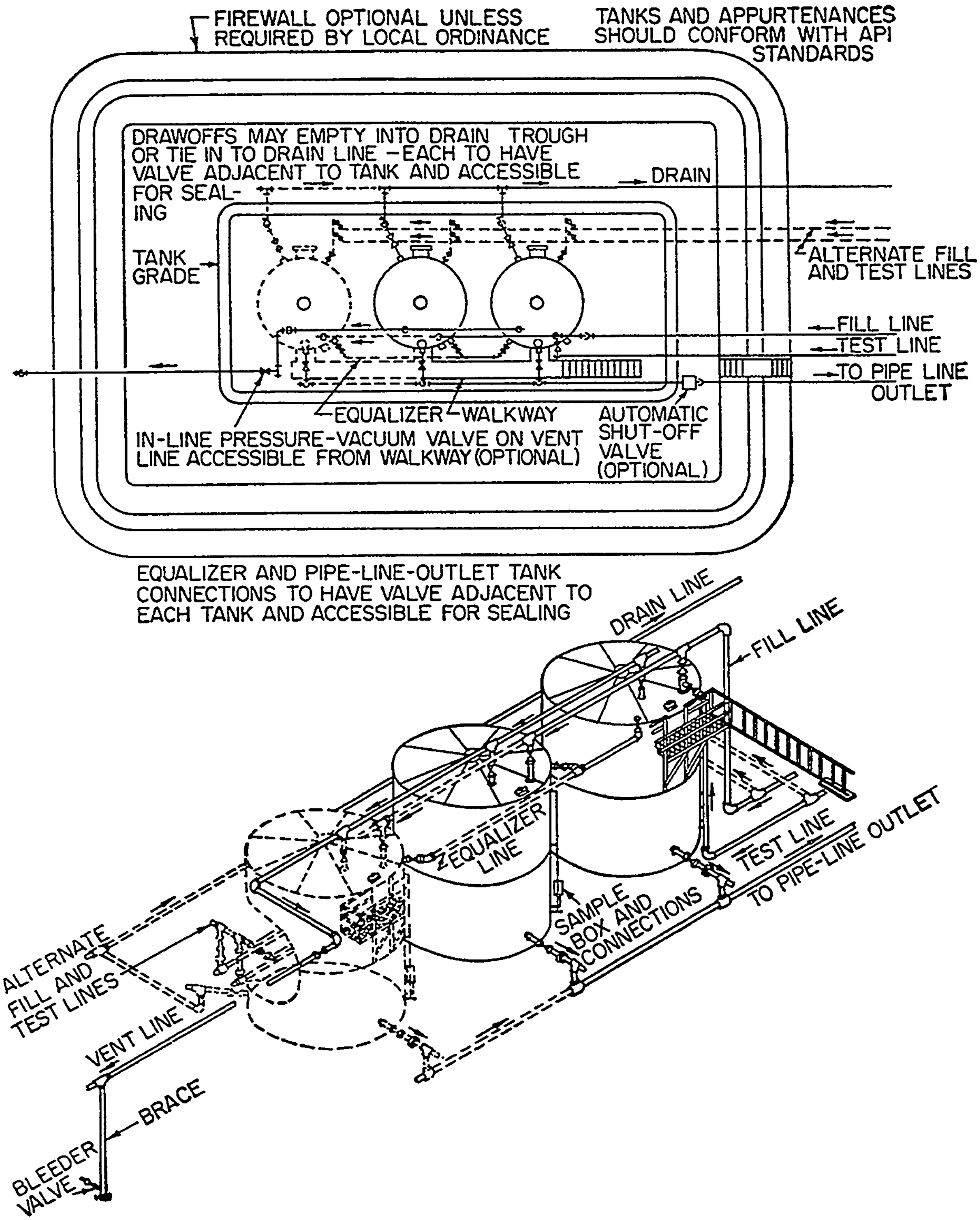

Figure 4 **Suggested setting and connection plan for typical tank battery**

1.3.1 Examples for an Onsite Inspection

In conducting an onsite inspection, there are many things that can cause inspectors to have reservations as to whether a Native American Tribe should make a decision to take over operations or require a previous operator to remove all equipment, plug all producing wells and injectors, and remediate/restore the surface and groundwater to its original condition. The following sections will describe some of the conditions to look for while conducting an onsite inspection of equipment and the environmental inspection.

1. While conducting an onsite inspection of equipment, wells, separators, tank batteries, etc., some of the things to check closely that will affect the decision to take over operations are listed as follows:
   - Engines and/or motors that are not in working condition
   - Engines and/or motors that are in poor condition because of rust or corrosion
   - Pump jacks that are in poor condition because much of the walking beams or other parts have damage and/or are rusted out (Fig. 1)
   - Bearings on the counter balance, pitman side members, center bearing, etc. that are worn or in generally bad condition beyond economical repair (Fig. 1)
   - Pump jacks that are not in working condition (Fig. 1).
   - Separators and/or storage tanks that are badly rusted, causing thin spots or leaks
   - The bottom of storage tanks that are leaking (Fig 4)
   - Tubular goods on pipe racks that are rusty and have holes that will leak
   - Corrosion, rust, and leaks on lead lines
   - Leaking at stuffing box at wellhead (can be remediated by replacement of rubber seals in stuffing box)
2. While an inspector conducts an environmental investigation of a petroleum producing lease, it will help to know the following:
   - Environmental history
   - Location of disposal wells,
   - Location of pits even if they have been closed and/or remediated and restored to natural condition
   - Location of salt water holding tanks and pits, waterflood supply and water treatment facilities as shown by the example in Figure 5
   - Location of oil/salt water spills, even if they have been remediated and restored to natural conditions
   - Location of pipelines, etc.

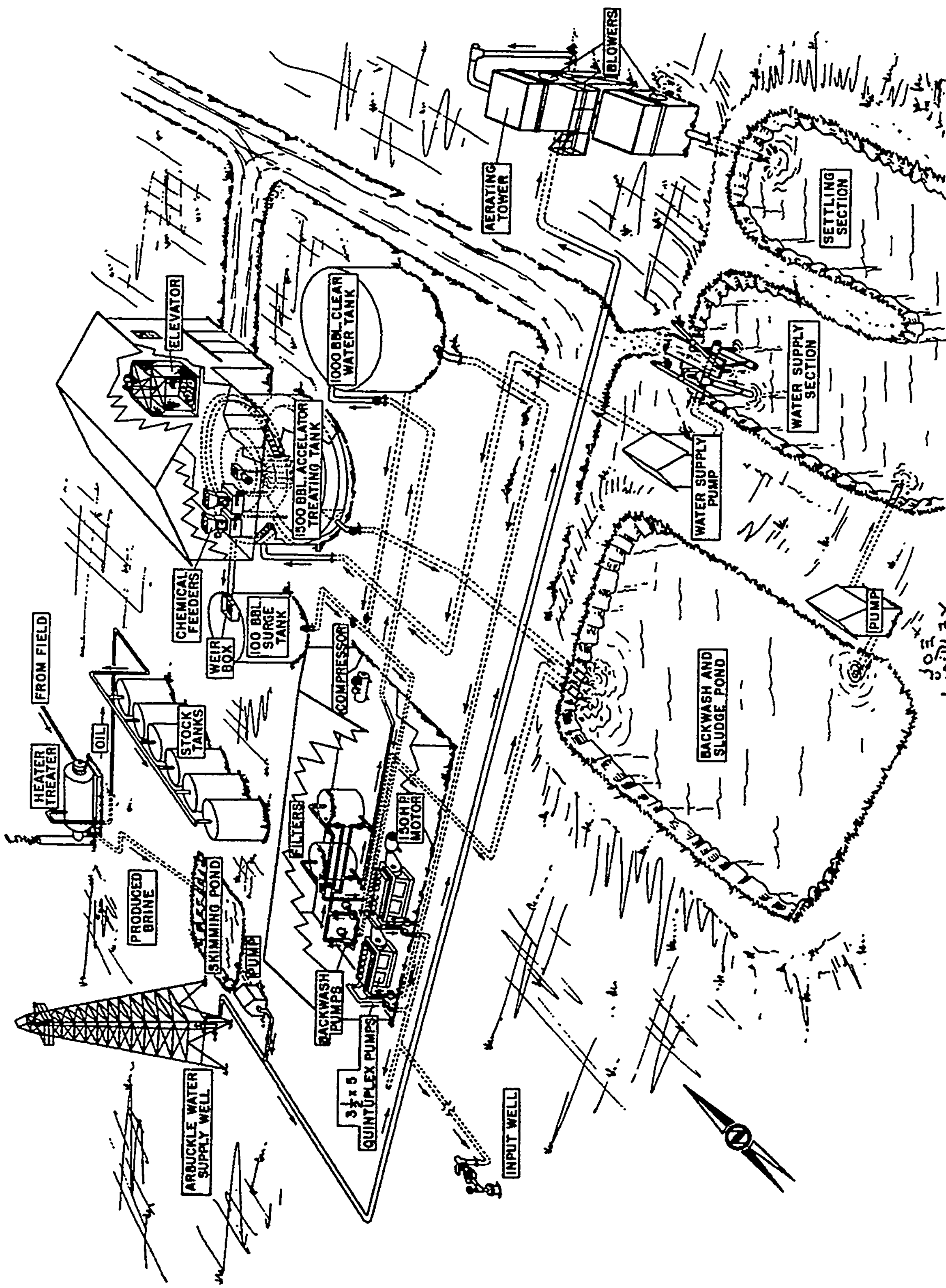

Figure 5 Early lease waterflood water-treating plant

When investigating spill sites, look for very fine to prominent white, crystalline crust on the surface of the soil. The white, crystalline substance is likely to be salt residua left over from a salt water spill, salt water holding pits, or settling ponds. This substance is particularly noticeable during dry summer months. Salt water spills are commonly remediated by tilling in agricultural gypsum into the soil, frequent watering, and tilling after initial application of gypsum. When an investigator thinks that a salt water spill location has been encountered, soil samples should be taken in sterile, numbered sample jars and taken to an environmental analysis laboratory for analysis. Usually the laboratory can suggest the amount of gypsum needed to remediate salt in the soil if the volume of soil for remediation is known. Waterflooding supply and water treatment facilities in use from the 1940s, 1950s, and 1960s are generally located where salt water soil damage can be found. Various designs of these facilities may be seen in the example shown in Figure 5 in the text and Figures 6–10 in Appendix E. Salt water holding ponds, settling ponds, and ditches used in waterflooding during this era were opened and were not lined. Generally when these facilities were abandoned and closed, before environmental laws were passed that terminated this practice requiring remediation, the holding pits, settling ponds, and ditches were covered with dirt without remediation. In the early days of oil and gas production, produced formation salt water was drained downgrade from separators and tank batteries. Abandoned location of separators and tank batteries are good places to look for salt water damage to soil.

Oil spills onto the surface of the land are commonly more unsightly than damaging if they do not have salt water associated with the oil. Crude oil is biodegradable with natural microbes in the soil or by applying microbial cultures to the soil for faster degradation. Application of mixed fertilizer (in the right proportion, frequent watering, and tilling will quickly remediate crude oil spills in the warm spring, summer, and fall months. In applying this process, it is helpful to add some straw or hay as mulch to increase the water holding ability of the soil in order to keep the microbes working to clean up the site. It is important to keep records of soil analyses for hydrocarbon content of the soil throughout the remediation process. Again, samples of contaminated soil should be taken in sterile, numbered sample bottles for analysis by an environmental analysis laboratory. Native American Tribes may want to remediate sites, but it is advisable to find the responsible operator and require this operator to finance remediation by an experienced environmental remediation firm.

Investigators should walk pipelines located on maps of the leases to inspect for breaks and leaks, particularly if plastic or rubber lines are on the surface in an area where there are frequent grass fires or brush fires during dormant months for vegetation. They should check to make sure that there are no electric wires on the ground to threaten the safety of humans and animals. Storage tanks should be investigated for spills and to see whether they are properly diked and lined to hold a volume of liquid (oil) equal to the holding capacity of all storage tanks within the diked area. Wooden storage tanks and wooden salt water tanks (Fig. 15) commonly used before the 1970s and sometimes still in use are a common site of oil and/or salt water contamination. Wooden storage tanks commonly leak, which may have caused widespread soil and/or water contamination. These sites should be located and remediated. Check along streams to assure that no oil and/or salt water has leaked into porous/permeable underground layers that may drain into streams or lakes. While checking for leaks, inspectors should assure that there is material onsite that can be used for containment and soaking up of spills. Oil spills into streams are commonly contained and soaked up with hay kept onsite. Investigators should be aware that former operators may have buried empty chemical cans or left them on the surface, common practices in the past. It is advisable for Native American Tribes to require responsible operators and/or chemical manufacturers to dispose of empty chemical cans and drums and remediate sites where spills have occurred.

Environmental problems or perceived environmental problems on a lease can lead to a decision to forgo assumption of operations by Native American Tribes. If sites needing remediation are encountered during an inspection, the responsible operator should be contacted and the proper state and federal agencies should be notified. Appendix F contains a DOE/BDM publication entitled *Federal Environmental Regulations Impacting Hydrocarbon Exploration, Drilling, and Production Operations* that can be used along with this report as a handy reference for federal regulations and places to look for potential contamination from spills.

This section has discussed things that can happen on producing oil and gas leases and some locations on leases where they can be found, but very few oil fields today have some of the conditions discussed in this section. If inspectors are looking for these conditions on leases that were producing before the 1970s, they are likely to find indications of practices that operators know are not environmentally condoned today. Old leases may have some unremediated contaminated soil.

1.4 FINAL DECISION

After investigators have completed a pre-onsite investigation that examines courthouse records and lease records, and an onsite investigation that covers equipment and an environmental investigation, the data collected will allow Native American Tribes to make a fact-based decision on whether to assume operations on producing properties. There are three options:

- Option 1—With all inspections having no negative data or little negative data that is easily remediated, a decision to assume operations can be made.
- Option 2—With cumulative negatives throughout the investigation, a Tribal Council may make a decision to assume operations after all negatives have been remediated or cleared by previous operators to the satisfaction of state, local, and federal regulatory agencies and the Native American Tribes.

- Option 3—The previous responsible operator is to complete remediation and close the property, particularly if the remaining resource is not economical.

The procedure set forth in this report can lead Native American Tribal investigators with little or no experience through an investigation before assuming operations of producing leases.

1.5 SUMMARY

Native American Tribes are either considering assumption of operations of petroleum producing properties or have assumed operations of petroleum producing properties on Native American Tribal lands. Protocols set forth in this report along with other forms and reports in the appendices will lead investigators with little or no experience in producing property inspection through inspection and appraisal of petroleum producing properties on Tribal lands. This report describes some potential environmental contamination on sites associated with petroleum producing properties, but usually found on a few older properties where many practices considered environmentally unsound today were practiced before the 1970s. Most problems found on producing properties can be remediated or cleaned up by negotiating with former operators of properties. The report will lead investigators through the inspection, reservoir analysis, and economic analysis to a fact-based decision to proceed with an assumption of operations or remediation and closure of the property.

2.0 REFERENCES

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Powell, John P., and J. L. Eakin. 1952. *Waterflooding in Nowata County, Oklahoma, Oil Fields.* Bureau of Mines Report of Investigation 4896, Figures 4, 6, 8, and 10.

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APPENDIX A

RESERVOIR ANALYSIS SPREADSHEET

A-1.0 USING THE SPREADSHEET FOR RESERVOIR ANALYSIS

The reservoir analysis spreadsheet has been designed to calculate subsea depths of the top and base of formations/reservoirs, water and oil saturation (Sw & So) from resistivity and porosity log picks, volumetric reserve calculations of original oil in place (OOIP), remaining oil in place (ROIP), and fractional oil produced per well and for the reservoir. In the spreadsheet 200 rows are programmed for these calculations.

When the user has entered all of the reservoir data available, data needed to calculate oil reserves can then be averaged. To average a column of numbers in MS EXCEL the user should highlight an empty space at the base of the column of numbers. Then pull down the insert menu, open function, highlight average, press the finish button, and highlight the column of numbers that you want to average. When all of the reservoir characteristics are averaged the formula programmed into the spreadsheet will automatically calculate oil reserves, etc.

On the accompanying computer disk there is a document entitled RESANALY.XLS that is a MS EXCEL spreadsheet and a Lotus 1-2-3 spreadsheet entitled RESANALY.WK3. These spreadsheets are programmed to perform the calculations described in Table 1. By saving the reservoir analysis spreadsheet as a re-named document the user is able to keep the "blank" template for analyzing other reservoirs or fields. On the same computer disk there are 2 documents that show examples of how the program is used to perform the calculations described in Table 1, they are entitled EXAMPLE.XLS and EXAMPLE.WK3. These spreadsheets have been saved in both EXCEL and Lotus formats in order for users of the respective systems to easily use the format that they are familiar with.

With approval from the Department of Energy (DOE) and BDM-Oklahoma, Inc. a disk with the programmed spreadsheets and the example can be distributed to Native American Tribe members evaluating petroleum resources or to small independent operators upon request. The remainder of this report is a users guide for the use of this spreadsheet.

A-2.0 SUMMARY

A Microsoft EXCEL spreadsheet was developed and programmed by BDM-Oklahoma, Inc. personnel to perform calculations as data is entered. The objective for developing the programmed spreadsheet was to make the process of analyzing petroleum reservoirs faster and easier for a first look. This spreadsheet provides Native American Tribal members and small independent operators a method to evaluate the petroleum resource on the Osage Mineral Estate or on leases in areas outside the estate. A computer disk with the reservoir analysis software and an example accompany this report.

TABLE 1

DESCRIPTION OF RESERVOIR ANALYSIS WORKSHEET

COLUMN	FORMULA	DESCRIPTION
A	None	Operator
B	None	Location - Section - Township - Range or oth designation of choice by the user
C	None	Well Number
D	None	Elevation
E	None	Reservoir or Formation name
F	None	Reservoir/Formation Top measured depth (MD)
G	=D2-F2	Reservoir/Formation Top subsea depth (SS) calculated by formula
H	None	Reservoir/Formation Base measured depth (MD)
I	=H2-F2	Reservoir/Formation Thickness - calculated b formula
J	None	Gas Cap (net feet)
K	None	Net Oil Pay (feet)
L	None	Average Porosity (%) as a decimal (e.g. 0.15)
M	None	Average Resistivity of Pay Zone From Resistivi Log (Rt)
N	None	Perforations or Pay Zone Shot Open hole wi Nitroglycerin (e.g. 1525'-1550' or Shot 1525 1550' w/150 qt.)
O	None	Driller's Log Top (DL Top) Reservoir/Formation
P	None	Driller's Log Base (DL Base) Reservoir/Formation
Q	None	Lithology (e.g. SS-sandstone, LS-limestone, Do dolomite)
R	None	Initial Production (IP) - Barrels of Oil Per Da (BOPD)
S	None	Resistivity of Reservoir Water (Rw) - Th Oklahoma City Society of Petroleum Enginee publishes a book of measured Rw values b formation by county, Section-Township-Range.
T	=IF(L2="unknown","unknown",SQRT(((1/(L2*0.01*L2*0.01)*(S2))/M2)))/0.01	Reservoir Water Saturation (Sw) calculated wi the Archie formula programmed into Column of the spreadsheet
U	=IF(T2="unknown","unknown",100-T2)	Reservoir Oil Saturation (So) as a perce calculated by subtracting the calculated Sw fro 100.
V	None	Cumulative Oil Production for: lease, field, wel etc.
W	=IF(Z2=0,"unknown",IF(MIN(L2)=0,"unknown",7758.4*Z2*IF(L2=0,0.24,L2*0.01)*MIN(K2)*IF(U2>0,U2*0.01,0.6)))	Calculated Estimated Original Oil In Pla (OOIP) by using a volumetric formula. NOT the porosity will default to 0.24 (24%) if th porosity of the reservoir is not known. This ca be changed in the formula if the user would li another default number for porosity if porosity the reservoir is unknown. S *IF(L2=0,0.24,L2*0.01.
X	=IF(W2="unknown","unknown",IF(V2=0,"unknown",W2-V2))	Calculated Estimated Remaining Oil In Pla (ROIP) by subtracting the cumulative production from the calculated OOIP in Colum W.
Y	=IF(W2="unknown","unknown",V2/W2)	Calculated Fractional Oil Recovery by dividi the Cumulative Oil Production in Column V b the Calculated Estimated OOIP in Column W.
Z	None	Area (acres) for: well, field, reservoir, etc.
AA	None	Number of Wells for: reservoir, field, etc.
AB	=V2/AA2	Average Oil Recovery Per Well (Rec/Well Cumulative Oil Production divided by Number Wells in the: Reservoir, Field, Fault Block, etc.
AC	=D2-H2	Subsea Base of Reservoir/Formation.
AD	None	Oil and/or gas shows from well records for ea well.
AE	None	Completion Date for each well.
AF	None	Depth of Production Casing.

APPENDIX B

LONG FORM EVALUATION OF WORKING INTEREST

Long Form Evaluation of Working Interest

1	2		3	4	5	6	7	8	9
Year	Gross Production		Gross income WI ($)	Lifting cost ($)	Net income ($)	Present value of net income ($)	Investment ($)	Cumulative net present value ($)	Present value of 100% oil & gas
	Oil (bbls)	Gas (MMCF)							
___	___	___	___	___	___	___	___	___	___
___	___	___	___	___	___	___	___	___	___
___	___	___	___	___	___	___	___	___	___
___	___	___	___	___	___	___	___	___	___
___	___	___	___	___	___	___	___	___	___

NOTE: Continue until anticipated ultimate depletion. Discount Column 6 at the appropriate rate, compounded annually, payment received at the end of the interest period. See explanation of the Long Form Evaluation of Working Interest table below.

Analysis of Economics

The best method of presenting the economics on a petroleum producing project is indefinite. The method used should present the pertinent facts in a form that is easily understood by the reader and that serves the intended purpose. If there is any doubt, the best approach is to discuss the matter with the recipient and work out the best approach.

A classical form (above) is known as a nine-column long form evaluation of a 7/8 (87.5%) working interest. It may be expanded to include a particular interest. It is described as follows:

Column 1: **Year.** Number of years that the well will be producing.

Column 2: **Gross recovery.** This is the total hydrocarbons (in barrels) produced during each year.

Column 3: **Value of 7/8 working interest at $..... per barrel:** This is the production given for the particular year in Column 2 multiplied by the income of the working interest per barrel of oil produced.

Column 4: **Lifting cost.** This is 12 times the monthly cost under flowing conditions or under artificial lift, whichever is applicable for the particular year.

Column 5: **Net value.** This is the particular year's value as given in Column 3 minus the particular year's expenses as given in Column 4.

Column 6: **Net present value at .... percent.** This is the figure for the particular year in Column 5 multiplied by the proper deferment factor.

Deferment factors are based on compound interest. If the money value of the production is considered as being available at the end of the year, and where interest is compounded annually, a deferment factor of $(1/1 + i)^m$ may be used, where i is the interest rate expressed as a decimal and m is the number of the year as given in Column 1.

Column 7: **Investment, present value.** This number includes the development cost in the first year, installation of artificial lift equipment in the proper year (reduced to its present value), and the ultimate salvage value (reduced to its present value) as a red figure in the last year of production.

Column 8: **Overall cumulative net present value.** For any year, this is the previous figure in Column 8 plus the particular year's figure in Column 6 minus that in Column 7. Thus, for the first year it will be simply the figure in Column 6 minus the figure in Column 7, which will generally give a red figure for the first year. Payout occurs when the figures in Column 8 change from red to black.

Column 9: **Present value of 8/8 (100%) oil and gas:** For any particular year, this is the gross recovery given in Column 2, multiplied by the proper income per barrel of oil produced, multiplied by the proper deferment factor .

APPENDIX C

PRE-ONSITE INSPECTION CHECKLIST

PRE-ONSITE INSPECTION CHECKLIST

Courthouse Records Check

1. Lease Terms

- Royalty interest ____________ %
- Net revenue interest (NRI) _________ %
- Overriding royalty interest (ORRI) _________ %
- Shut-in royalty payment obligation ________________________________
- Drilling obligations ____
- Location damage payment obligations ______________________________
- Seismic damage payment obligation ________________________________
- Pit closure obligation ____
- Gate/cattle guard/lock obligation __________________________________
- Distance from buildings/houses obligation __________________________
- Lease restoration obligations at abandonment _______________________
- Livestock death payment ____
- Salt water/oil spill damage obligation ______________________________
- Pipeline depth obligation ____
- Pooling terms ____
- Unitization terms ____

2. Division orders

- Distribution of royalty ______________________________
- Working interest (WI) partners ______________________________
- Working interest distribution ______________________________
- Operator of record ______________________________

3. Litigation record

- Drainage litigation: yes _____ no _____ Date ______________

  judgment ______________________________
- Environmental: yes _____ no _____ Date ______________

  judgment ______________________________
- Damages: yes _____ no _____ Date ______________

  judgment ______________________________
- Bankruptcy: yes _____ no _____ Date ______________

  judgment ______________________________
- Financial: yes _____ no _____ Date ______________

  judgment ______________________________
- Bank Lien: yes _____ no _____ Date ______________

  payment/judgment ______________________________

Lease Records

1. Well Records

    - Drilling program for discovery well and development wells
    - Well construction records
    - Geology records of wells
    - Logging records
    - Completion records
    - Cement records
    - Perforation records
    - Open hole test records with pressure build-up curves
    - Location clearing and cleanup records

2. Production Records

    - Completion test records
    - Cost of electricity for producing wells, waterflood injection wells, and salt water injection wells
    - Records of road construction and maintenance for producing lease
    - Production records: monthly, annual, and total
    - Well workover/recompletion records: individual wells, reservoirs, and field wide
    - Oil/gas sale record: monthly, annual, and total
    - Production pipeline construction records
    - Lead lines (production pipelines to tank battery)
    - Distribution of proceeds: monthly, annual, and total
    - Production pressure records: monthly, annual, and total

3. Reservoir Records

- Coring records
- Core analysis
- Petrophysical properties
- Reservoir characterization records
- Reservoir management plans/revisions
- Reservoir thickness for each reservoir: gross sand, gross pay, and net pay
- Open hole electric log surveys
- Open hole electric log analysis/comparison to core analysis
- Structure maps
- Reservoir maps: gross thickness, gross pay, net pay, gross porosity, and net (average) porosity
- Cement bond logs
- Lithology logs

4. Environmental Records

- Environmental citations
- Number of environmental violations and type
- Type of environmental citations
- Material safety data sheets (MSDS) on file for chemicals used on lease
- Inventory of material to clean up oil/salt water spills: yes ____ no ____
- Number of salt water disposal wells
- Number of pressure maintenance/waterflood injection wells

- Mechanical integrity tests: pass ______ fail ______
- Oil/salt water spill records: pipelines ______ tank batteries ______

  wellhead ______
- Construction records of waterflood injection wells and saltwater disposal wells
- Number of groundwater monitoring wells and why they are required at this producing facility?
- Groundwater monitoring well drilling records
- Geology records of groundwater monitoring well(s)
- Groundwater monitoring well construction records
- Geologic maps of top of groundwater and thickness of groundwater
- Analysis records of groundwater and salinity of salt water contaminating groundwater
- Frequency of groundwater sampling from monitoring well(s)
- Salt water production: daily/well/lease ______ monthly/well/lease ______

  annual/well/lease ______
- Salt water disposal pressure and/or waterflood injection pressure
- Location map showing salt water holding tanks on surface of lease
- Records of environmental inspection and findings of surface of lease
- Records of open pit closure

5. Equipment Records

- Lease equipment inventory
- Record of original purchase price of equipment from operator
- Records of current operator appraised value of equipment

- Lien(s) on equipment
- Location map of equipment on surface
- Location and/or construction drawings of equipment downhole in wells
- Records of condition of equipment
- Records of equipment replacement
- Records of life of tubular goods and sucker rods in producing wells
- Records of life of tubular goods in waterflood injection wells and salt water disposal wells
- Records of life of injection pumps for waterflood injection wells and salt water disposal wells
- Repair records for all surface equipment
- Records for workover and frequency of workover for all producing wells
- Oil storage tanks: number ______ capacity ______
- Oil storage tank calibration chart(s): yes ______ no _____

APPENDIX D

SITE INSPECTION CHECKLIST

SITE INSPECTION CHECK LIST

Lease Inspection

1. Equipment

- Oil storage tanks: number ______ capacity ________
- Oil storage tank(s) match to location map: yes _____ no ________
- Oil storage tank calibration chart on lease: yes _____ no ________
- Oil storage tank match to inventory list: yes _____ no ________
- Condition of oil storage tanks: excellent ____ good _____

  fair ____ poor _____

  comments: ____
- Oil storage tank(s) have dike: yes ______ no ______

  comments: ____
- Oil/water separator(s): number ____ capacity ________
- Oil/water separator(s) match to location map: yes ___ no ___
- Oil/water separator(s) calibration chart on lease: yes ___ no ___
- Oil/water separator(s) match to inventory list: yes ___ no ___
- Condition of oil/water separator(s): excellent ___ good ___

  fair ____ poor _____

  comments: ____
- Pumping units: number _______
- Pumping units match to location map: yes _____ no ________
- Pumping units match to inventory list: yes _____ no ________

- Condition of pumping units: excellent ____ good ____

  fair ____ poor ____

  comments: ____

- Pipelines match to location map: yes ____ no ____
- Pipelines match to inventory list: yes ____ no ____
- Condition of pipelines: excellent ____ good ____

  fair ____ poor ____

  comments: ____

- Salt water disposal well(s): number ____ capacity ____
- Disposal well(s) match to location map: yes ____ no ____
- Disposal well(s) match to inventory list: yes ____ no ____
- Disposal well(s) tanks: excellent ____ good ____

  fair ____ poor ____

  comments: ____

- Waterflood injection well(s): number ____ capacity ____
- Waterflood injection well(s) match to location map: yes ____ no ____
- Waterflood injection well(s) match to inventory list: yes ____ no ____
- Waterflood injection well(s) condition: excellent ____ good ____

  fair ____ poor ____

  comments: ____

- Condition of motors/engines: excellent ____ good ____

  fair ____ poor ____

  comments: ____

- Tubular goods match to inventory: yes ___ no ___

  comments: ____

- Condition of tubular goods: excellent ___ good ___

  fair ___ poor ___

  comments: ____

2. Environmental Condition

- Material safety data sheets (MSDS) on location: yes ___ no ___
- MSDS match to chemicals on location: yes ___ no ___
- Chemicals on lease match inventory: yes ___ no ___

  comments: ____

- Evidence of oil and/or salt water spill(s): yes ___ no ___
- Material to cleanup oil/salt water spill on lease: yes ___ no ___
- Oil/salt water spill at designated location: yes ___ no ___
- Have all oil/salt water spills been remediated? yes ___ no ___
- Salt water disposal well(s): number ___ capacity ___
- Disposal well(s) match to location map: yes ___ no ___
- Disposal well(s) match to inventory list: yes ___ no ___
- Disposal well(s) tanks: excellent ___ good ___

  fair ___ poor ___

  comments: ____

- Waterflood injection well(s): number ___ capacity ___
- Waterflood injection well(s) match to location map: yes ___ no ___
- Waterflood injection well(s) match to inventory list: yes ___ no ___

- Waterflood injection well(s) condition: excellent ______ good ______

  fair ____ poor _____

  comments: ____

- Oil storage tank(s) have dike: yes ______ no ______

  comments: ____

- Oil storage tank(s) dike hold tank capacity: yes ___ no ___

  comments: ____

- Open pits closed/remediated: yes ___ no ___

  comments: ____

- Groundwater monitoring well(s): number ___ capacity ___

- Monitoring well(s) match to location map: yes ___ no ___

- Monitoring well(s) match to inventory list: yes __ no ___

- Monitoring well(s) condition: excellent ___ good ____

  fair ___ poor ____

  comments: ____

- Surface condition around wells/tanks: excellent ___ good ___

  fair ___ poor ____

  comments: ____

- Mechanical integrity test results on lease: yes ___ no ___

  comments: ____

APPENDIX E

PICTORIAL EXAMPLES OF EARLY WATERFLOODS

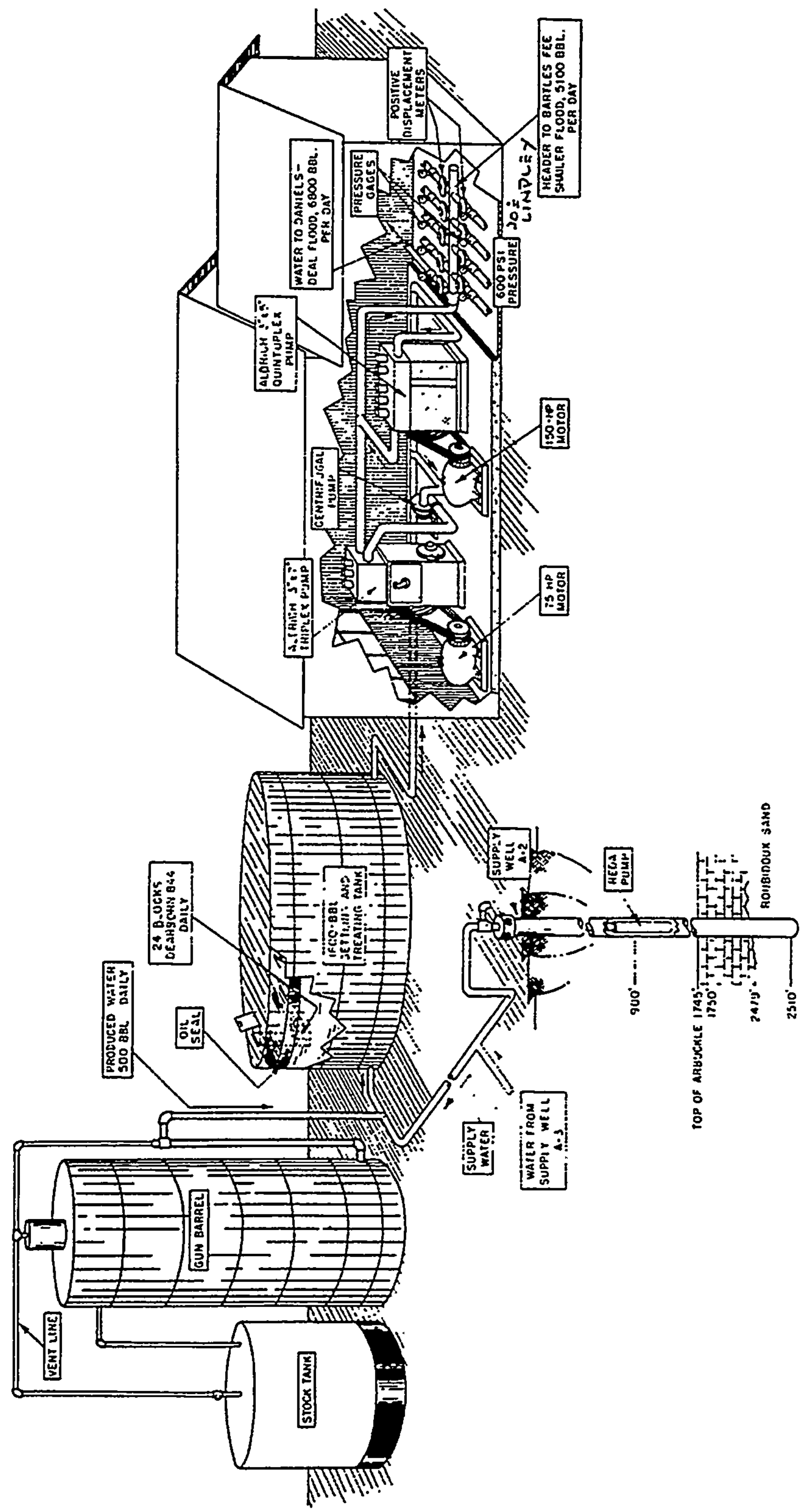

Figure 6 Lease waterflood; water plant, closed system

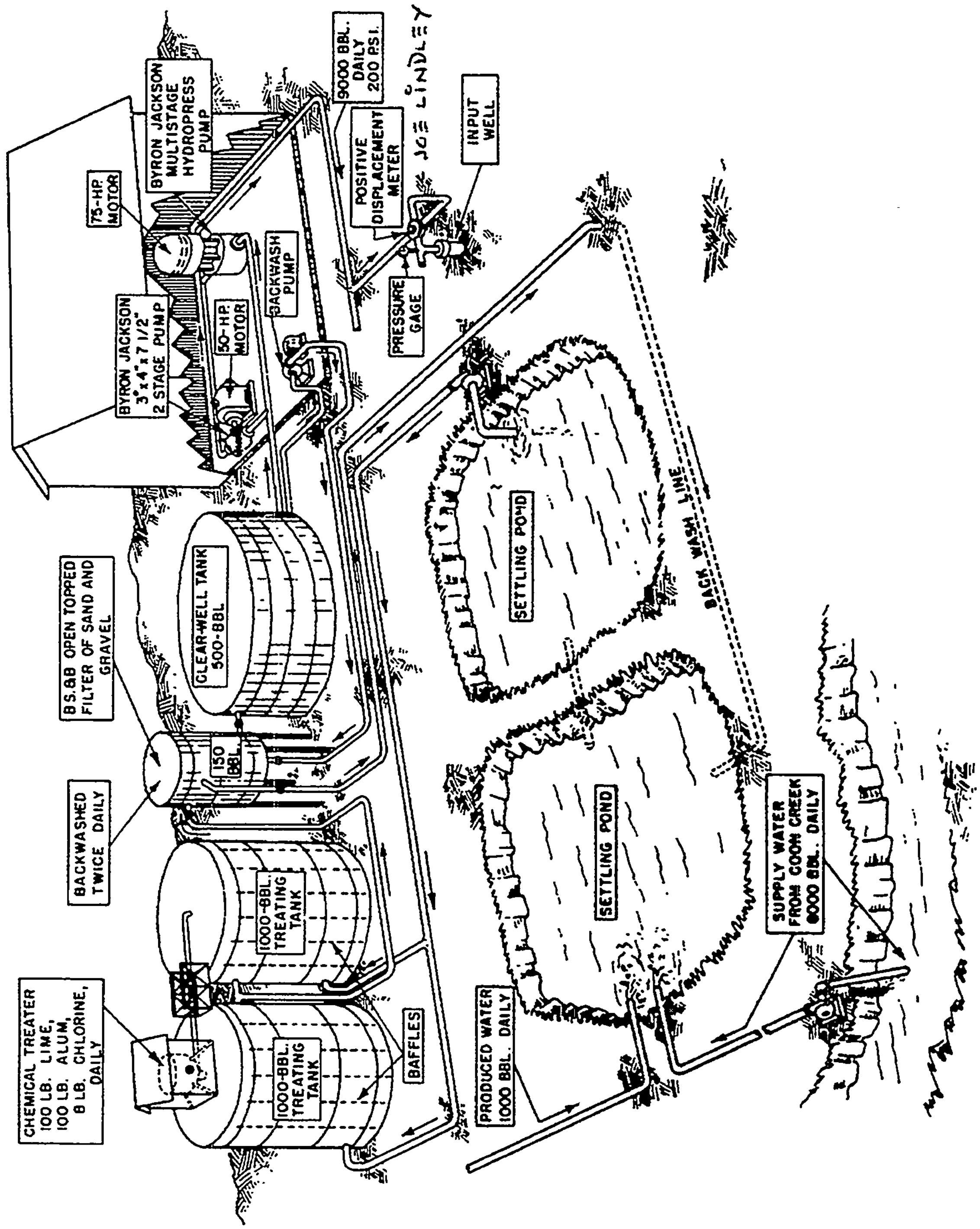

Figure 7 Lease water flood; water plant, open system.

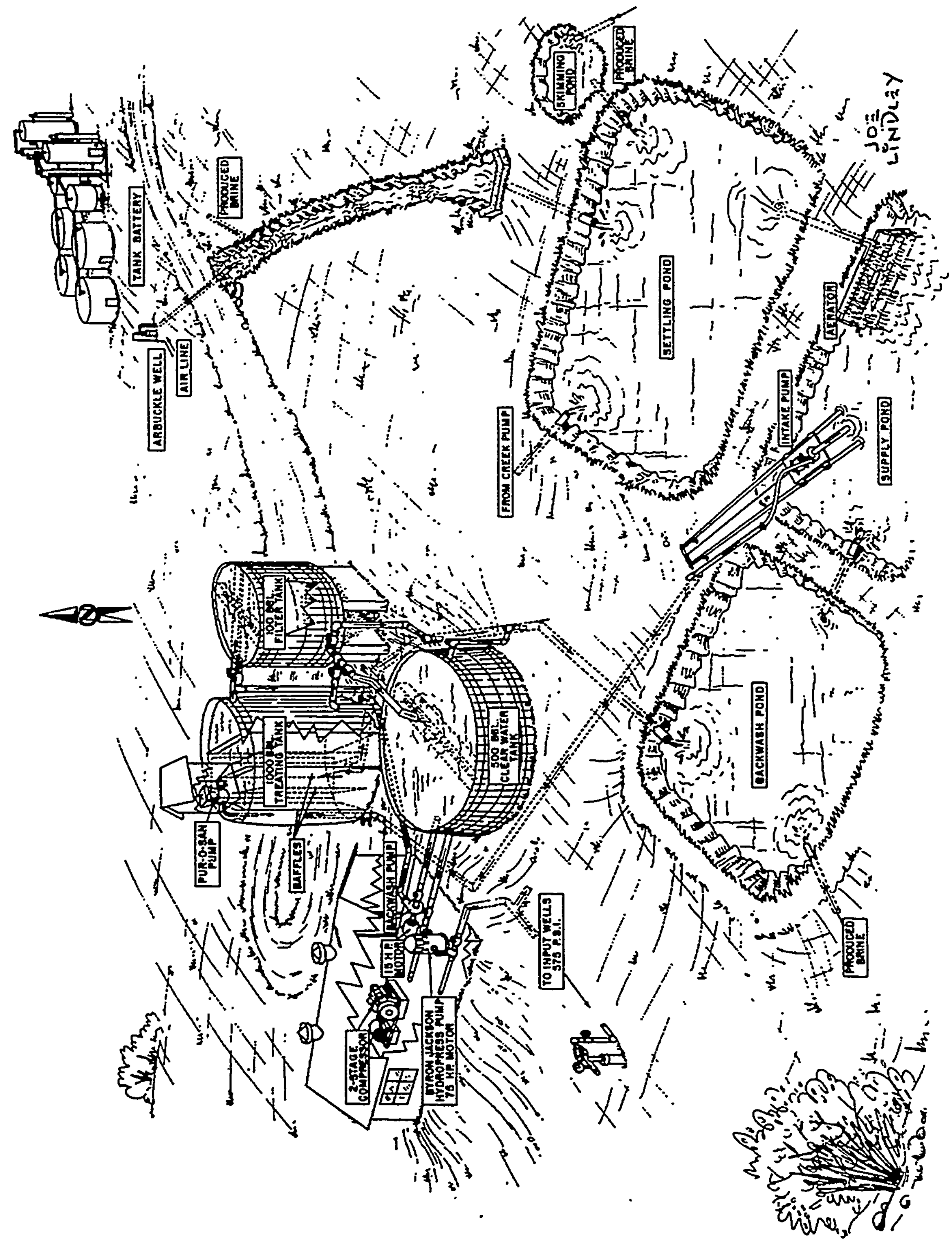

Figure 8 Early water-treating plant

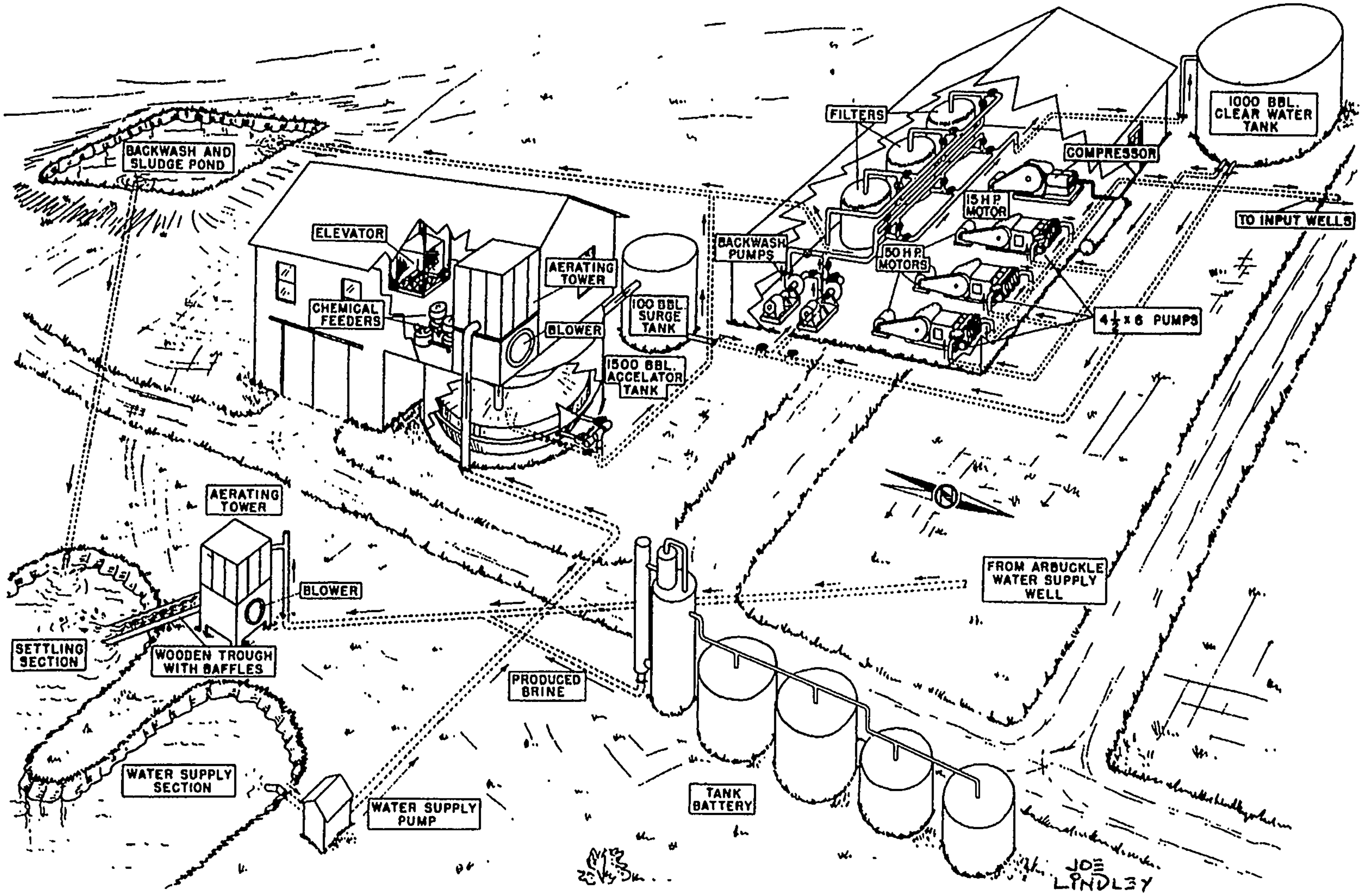

Figure 9 Water-treating plant

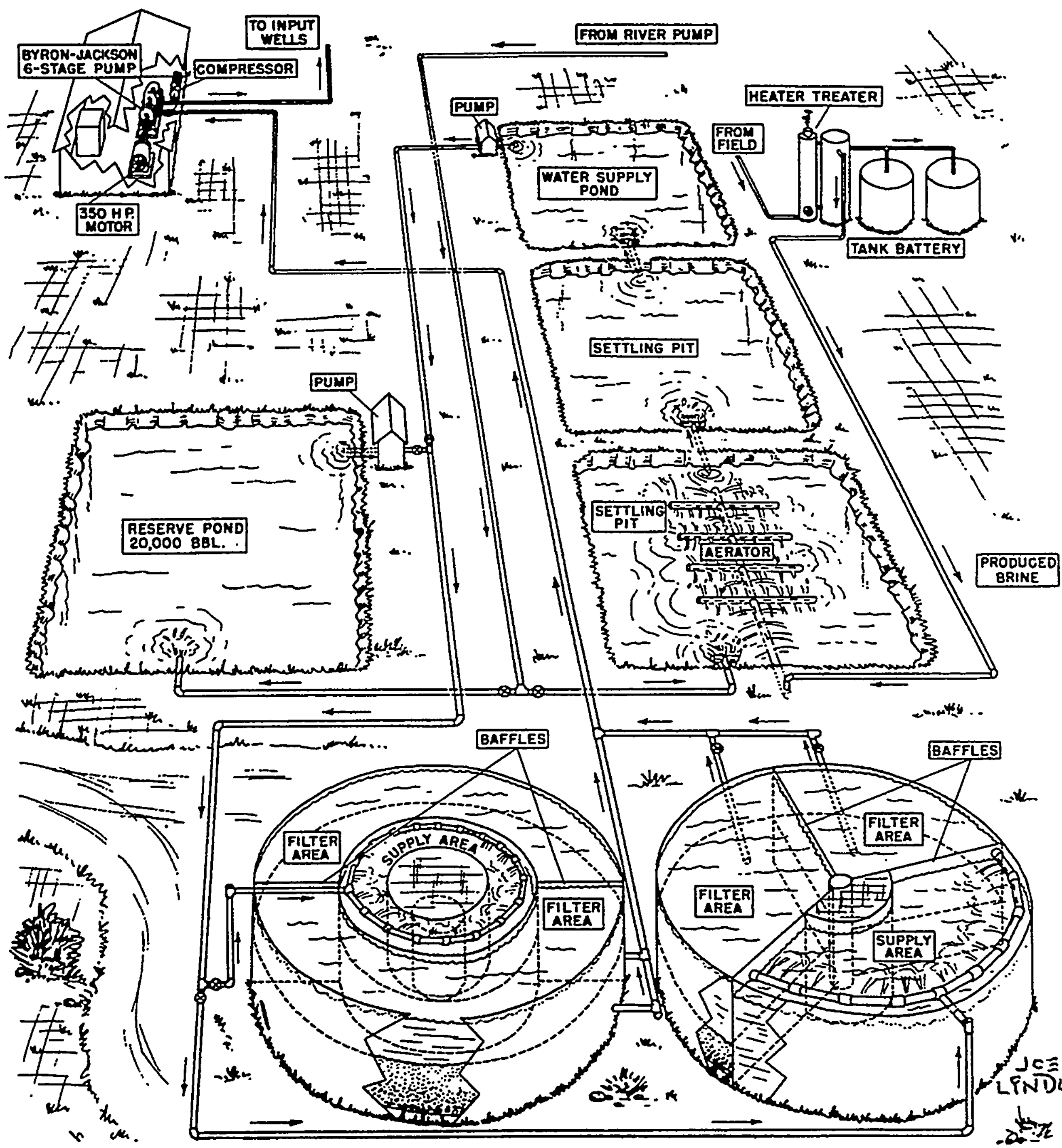

Figure 10 Water-treating plant for lease waterflood

APPENDIX F

NIPER/BDM-0130

TOPICAL REPORT

FEDERAL ENVIRONMENTAL REGULATIONS IMPACTING HYDROCARBON EXPLORATION, DRILLING, AND PRODUCTION OPERATIONS

NIPER/BDM-0130

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by

William I. Johnson and Herbert B. Carroll

March 1995

Work Authorization 95-A04

Work Performed Under Contract No.
DE-AC22-94PC91008

Prepared for
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Bartlesville Project Office

BDM-Oklahoma, Inc.
P.O. Box 2565
Bartlesville, Oklahoma 74005

ABSTRACT

Waste handling and disposal from hydrocarbon exploration, drilling, and production are regulated by the United States Environmental Protection Agency (EPA) through federal and state regulations and/or through implementation of federal regulations. Some wastes generated in these operations are exempt under the Resource Conservation and Recovery Act (RCRA) but are not exempt under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), Superfund Amendments and Reauthorization Act (SARA), and other federal environmental laws. Exempt wastes remain exempt only if they are not mixed with hazardous wastes or hazardous substances. Once mixture occurs, the waste must be disposed as a hazardous material in an approved hazardous waste disposal facility. Before the Clean Air Act as amended in 1990, air emissions from production, storage, steam generation, and compression facilities associated with hydrocarbon exploration, drilling, and production industry were not regulated. A critical proposed regulatory change which will significantly effect Class II injection wells for disposal of produced brine and injection for enhanced oil recovery is imminent. Federal regulations affecting hydrocarbon exploration, drilling and production, proposed EPA regulatory changes, and a recent significant United States Court of Appeals decision are covered in this report. It appears that this industry will, in the future, fall under more stringent environmental regulations leading to increased costs for operators.

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ACRONYMS

AOR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BIA	Bureau of Indian Affairs
CAA	Clean Air Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
Congress	United States Congress
CWA	Clean Water Act
DI	Direct Implementation
DOE	Department of Energy
DOT	Department of Transportation
E&P	Exploration and Production
EHS	Extremely Hazardous Substances
EPA	Environmental Protection Agency
GWPC	Groundwater Protection Council
HAP	Hazardous Air Pollutant
HAZCOM	Hazardous Communications
HMTA	Hazardous Materials Transportation Act
IPAA	Independent Petroleum Association of America
LEPC	Local Emergency Planning Committees
MIT	Mechanical Integrity Test
MSDS	Material Safety Data Sheet
NIPER	National Institute for Petroleum and Energy Research
NORM	Naturally Occurring Radioactive Material
NPDES	National Pollutant Discharge Elimination System
OPA	Oil Pollution Act
OSHA	Occupational, Safety, and Health Administration
OSW	Office of Solid Waste
PCBs	Polychlorinated Biphenyls
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
RQ	Reportable Quantity
SARA	Superfund Amendments and Reauthorization Act
SDWA	Safe Drinking Water Act
SIP	State Implementation Plan
SPCC	Spill Prevention Control And Countermeasure

TDS	Total Dissolved Solids
TIPRO	Texas Independent Procedures and Royalty Owners
TPQ	Threshold Planning Quantity
TSCA	Toxic Substances Control Act
UCI	Underground Injection Control
UIPC	Underground Injection Practices Council
USDW	Underground Source of Drinking Water
UST	Underground Storage Tanks

FEDERAL ENVIRONMENTAL REGULATIONS IMPACTING HYDROCARBON EXPLORATION, DRILLING, AND PRODUCTION OPERATIONS

1.0 INTRODUCTION

The United States Congress (Congress) has enacted laws for protection of human health and the environment and established the Environmental Protection Agency (EPA) for administration, oversight, and enforcement of environmental laws and regulations. In establishing the EPA, the Congress also delegated authority to write regulations by an established procedure, as they did with agencies such as the Department of Transportation (DOT) and the Occupational, Safety, and Health Administration (OSHA). In following these procedures, regulations promulgated by these federal agencies become law and are published in the United States Code of Federal Regulations (CFR). Over the past 24 years, since the establishment of the EPA, environmental regulations have had progressively greater impact on hydrocarbon exploration, drilling, and production. Principal acts that contain major provisions governing oil and gas exploration and exploitation are listed here and in Appendix A:

- Resource Conservation and Recovery Act (RCRA)
- Safe Drinking Water Act (SDWA)
- Clean Water Act (CWA)
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- Superfund Amendments and Reauthorization Act (SARA)
- Clean Air Act (CAA)
- Toxic Substances Control Act (TSCA)
- Oil Pollution Act of 1990 (OPA)
- Migratory Bird Treaty Act
- Endangered Species Act
- Hazardous Materials Transportation Act (HMTA)

This report is not intended as a guide for waste management by operators in hydrocarbon exploration, drilling, and production. However, it should heighten awareness of federal environmental regulations that currently affect operations in these areas. Many of the federal environmental regulations covering waste generated in these operations are covered in the following discussion.

Operators in this industry are coming under increased control of the EPA for waste (liquid and solid) disposal as well as air emissions. In order to stay in compliance, they must become more aware of federal and state environmental regulations, waste classification, approved waste disposal methods, and new, more stringent air emissions standards. The following sections of this report discuss the pertinent sections of each regulation affecting the exploration, drilling, and production industry.

2.0 RESOURCE CONSERVATION AND RECOVERY ACT

The Resource Conservation and Recovery Act (RCRA) was enacted by Congress in 1976. The objectives of this act are to promote the protection of human health and protect the environment while conserving material and energy resources. It requires the EPA to regulate the management of solid waste, hazardous waste, and waste disposal. According to regulations, solid waste may be either solid, semisolid, liquid, or partially gaseous.

Subtitle D of RCRA provides statutory authority to the EPA to regulate disposal of any solid waste. It also requires states to petition the EPA for approval plans for solid waste management. Under Subtitle D, states are to implement and enforce regulations for disposal of nonhazardous waste, provided that states develop regulations that meet minimum standards set by the federal government in Parts 256 and 257 of Title 40 of the U.S. Code of Federal Regulations (40 CFR). RCRA Subtitle D has not specifically developed regulations/guidelines for regulating waste generated in hydrocarbon exploration, drilling, and production operations, but it does provide clear statutory authority to do so.

Hazardous solid waste are regulated under RCRA Subtitle C. Statutory authority for federal regulations and enforcement for treatment, storage, and disposal of hazardous wastes is provided under Subtitle C. States that demonstrate, among other things, that their hazardous waste management programs are equivalent to and no less stringent than the federal regulatory program may be authorized by EPA to operate their own hazardous waste program. 40 CFR Parts 270–272 provide information about hazardous waste permits and state approval.

Congress amended RCRA in 1980 and 1984. In the RCRA amendments of 1980, Congress exempted certain wastes from regulation as hazardous wastes pending study by the EPA, but this exemption did not change the definition of hazardous waste. Congress gave an exemption to some wastes generated by hydrocarbon exploration and production operations from regulation under RCRA hazardous waste provisions in Subtitle C. Wastes that are exempt under Subtitle C are shown in Table 2–1; nonexempt wastes are shown in Table 2–2. The EPA was also directed to study these wastes and recommend appropriate regulatory action to Congress. The EPA study was to include an analysis of:

- Source and volume of waste
- Present disposal practices
- Danger to human health and the environment
- Documented cases of danger to human health and the environment
- Alternatives to current disposal methods

- Cost of alternative disposal methods
- Impact of alternative disposal methods on exploration and production

Table 2-1 EPA's List of Exempt Exploration and Production Wastes (Perry and Gigliello 1990)

The following wastes are listed as exempt in EPA's Regulatory Determination submitted to Congress and dated June 29, 1988. These wastes are primarily high-volume, low-toxicity wastes that are Subtitle D by today's definitions. This not a complete list of exempt wastes.

Produced water	Packing fluids
Drilling fluids	Produced sand
Rigwash	Hydrocarbon-bearing soil
Drilling fluids and cuttings from offshore operations disposed of onshore	Constituents removed from produced water before it is injected or otherwise disposed of
Cooling tower blowdown	Pigging wastes from gathering lines
Basic sediment and water and other tank bottoms from storage facilities that hold product and exempt waste	Wastes from subsurface gas storage and retrieval, except for the listed nonexempt wastes
Accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments	Liquid hydrocarbons removed from the production stream but not from oil refining
Pit sludges and contaminated bottoms from storage or disposal of exemption	Well-completion, treatment, and stimulation fluids
Gas plant dehydration wastes, including glycol-based compounds, glycol filters, filter media, backwash, and molecular sieves	Gas removed from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons
Waste crude oil from primary field operations and production	Materials ejected from a producing well during the process known as blowdown
Gas plant sweetening wastes for sulfur removal, including amine, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge	Light organics volatilized from exempt wastes in reserve pits or impoundments or production equipment
Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)	Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation
Workover wastes	

Table 2-2 EPA's List of Nonexempt Exploration and Production Wastes (Perry and Gigliello, 1990)

These nonexempt exploration and production wastes are potentially all Subtitle C units unless testing proves otherwise. This is not a complete list of nonexempt wastes.

Unused fracturing fluids or acids	Gas plant cooling tower cleaning wastes
Painting wastes	Drums, insulation, and miscellaneous solids
Vacuum truck and drum rinsate from trucks and drums transporting or containing nonexempt waste	Liquid and solid wastes generated by crude oil and tank bottom reclaimers
Refinery wastes	Radioactive tracer wastes
Used equipment lubrication oils	Waste compressor oil, filters, and blowdown
Used hydraulic fluids	Waste solvents
Waste in transportation pipeline-related pits	Caustic or acid cleaners
Boiler cleaning wastes	Boiler refractory bricks
Incinerator ash	Laboratory wastes
Sanitary wastes	Pesticide wastes
Oil and gas service company wastes, such as empty drums, drum rinsate, vacuum truck rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids	

The study of exempt and nonexempt exploration and production wastes was performed and submitted to Congress on December 28, 1987. On June 30, 1988, the agency made public its regulatory determination based on the report to Congress. These regulations were published in the *Federal Register* on July 6, 1988.

The definition of hazardous waste can be found in 40 CFR Part 261. The regulation identifies those wastes exempt from Subtitle C. When RCRA was enacted, it established identification procedures for hazardous and nonhazardous waste, and requirements for handling both types of waste. Four different criteria or characteristics were established for determination whether a waste is hazardous:

1. Reactivity

2. Corrosivity

3. Ignitibility

4. Toxicity

Determination by the Agency

The Agency has decided not to promulgate regulations under Subtitle C (for exploration and production wastes).

The Agency plans a three-pronged approach toward filling gaps in existing State and Federal regulatory programs by:

- Improving Federal programs under existing authorities in Subtitle D of RCRA, the Clean Water Act, and Safe Drinking Water Act
- Working with States to encourage changes in their regulations and enforcement to improve some programs
- Working with the Congress to develop any additional statutory authority that may be required

—EPA,
*June 30, 1988**

EPA also lists specific hazardous waste as poisons and carcinogens. Therefore, hazardous waste is described as characteristically hazardous or listed hazardous waste. Stringent hazardous waste disposal is regulated under RCRA Subtitle C regulations. If a nonhazardous exploration, drilling, or production waste is mixed with a hazardous waste, a characteristically hazardous waste, or a listed waste, the mixture becomes a hazardous waste and must be disposed of as such. Oil and gas operators must become aware of RCRA exempt and nonexempt wastes and approved methods of disposal. The American Petroleum Institute (API) published a guidance document for handling and disposing of exploration and production wastes.

To date, RCRA enforcement has largely been focused on Subtitle C hazardous waste, but Subtitle D solid wastes are becoming an increasingly larger part of EPA's overall enforcement picture. Currently, Subtitles C and D affect wastes generated in hydrocarbon exploration, drilling, and production, but underground storage tanks (USTs) are regulated under Subtitle I. USTs are not currently considered as part of hydrocarbon exploration, drilling, and production activities. The Subtitle C enforcement program includes compliance monitoring and enforcement against violations. Section 3007 of RCRA gives EPA, an authorized state, or a representative of either authority to conduct inspections that include examining facility records and obtaining samples. The frequency of inspection varies with the facility. The goal for enforcement actions of Subtitle C violations is to bring facilities into compliance and force the facilities to stay in compliance.

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* All shaded text in this report are quotations. The source for each is indicated at the end of the text.

Federal enforcement authority occurs when the EPA makes an Administrative determination that a state program is not adequate to address solid waste management facilities that may receive household waste or hazardous waste from small quantity generators.

—U.S. EPA

Some Enforcement Options Available under Subtitle C

- Informal actions such as written notices
- Administrative actions such as an order or hearing
- Civil actions filed in court
- Criminal actions against firms or individuals

—EPA

The complex relationship between compliance monitoring and civil enforcement is shown in Figure 2–1.

2.1 Disposal Of RCRA Exempt and Nonexempt Wastes Generated in Hydrocarbon Exploration and Production Operations

Wastes generated in hydrocarbon exploration and production operations that are exempt do not have to be treated or disposed of as hazardous wastes under RCRA. These are wastes that are generated as a result of drilling wells, completing hydrocarbon-producing formations, producing hydrocarbons, and processing hydrocarbons. Some exempt wastes are the results of maintenance and well-stimulation practices. Generally, RCRA-exempt solid waste can be disposed of in a landfill, and RCRA-exempt liquid waste can be disposed of in a disposal well. Well-completion, treatment, and stimulation fluids are considered exempt under RCRA after use in these activities because they no longer exhibit hazardous characteristics. Wastes that are exempt under RCRA Subtitle C are shown in Table 2–1. Table 2–1 lists pit sludges and tank bottoms as exempt under RCRA, but a recent Ninth Circuit Court of Appeals ruling that will be discussed later in this report did not exempt tank bottoms from disposal as hazardous under CERCLA. Wastes that are exempt under RCRA are not necessarily exempt under other environmental regulations. Loss of exemption for wastes generated in these operations will increase the cost and lower any profits that may be generated by producing and selling hydrocarbons.

There are usually multiple disposal options for RCRA Subtitle C–exempt wastes. Produced water can be disposed in an offsite commercial pit, Class II injection well, or surface discharge. Surface discharge of produced waste is with a national pollution discharge elimination system (NPDES)

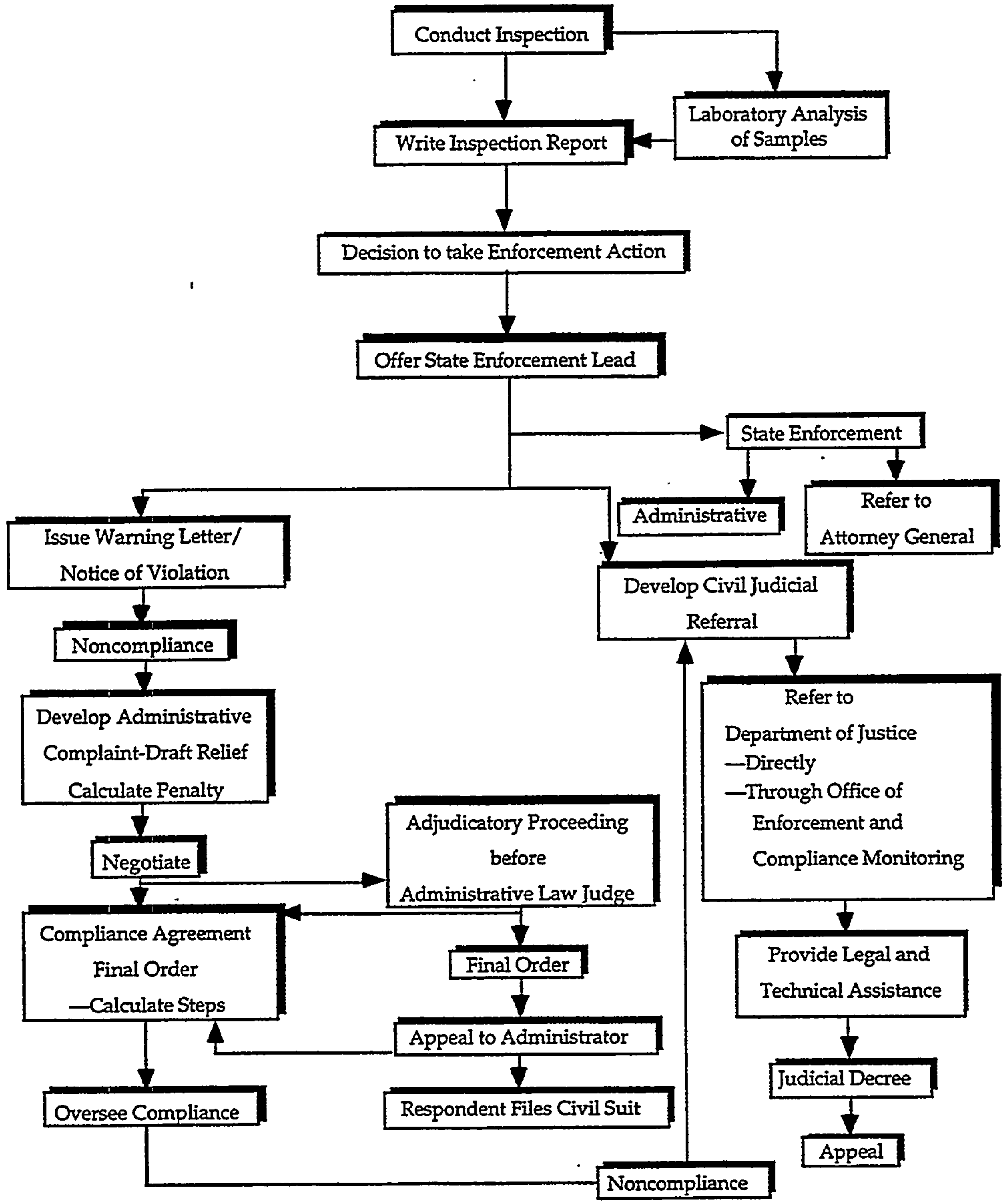

Figure 2–1 Compliance Monitoring & Civil Enforcement (Perry and Gigliello 1990)

permit only. NPDES permits for surface discharge of produced water ≥ 10,000 ppm total dissolved solids (TDS) are not issued, and permits for discharge of produced water < 10,000 ppm TDS may be difficult to get because of the composition of produced water. Weighted water and spent acid may be disposed in offsite commercial pits or by underground injection. Paraffin associated with produced crude oil can be disposed of by reclamation and/or recycling or underground injection. Used treatment chemicals can be disposed of by reclamation and/or recycling or underground injection. There is a list of disposal options for typical oil and gas wastes in Appendix B.

Nonexempt wastes generated in hydrocarbon exploration and production operations have to be treated and disposed of as hazardous wastes under RCRA. Unused well-fracturing fluids and acids for well stimulation are considered nonexempt wastes under RCRA. Service companies do not carry these fluids back to their yards to be returned to stock. Therefore, they must be treated, handled, and disposed of as hazardous waste because they exhibit hazardous characteristics. Exploration and production wastes that are RCRA-nonexempt wastes are shown in Table 2–2. Failure of operators to treat, handle, and dispose of nonexempt waste as hazardous can result in contamination, cause operators to become responsible for expensive cleanup operations, and result in fines for the operator by state and/or federal regulatory agencies. Improper handling and disposal of RCRA-nonexempt waste increases the cost of operations for operators in hydrocarbon exploration and production operations. Used empty oil and chemical drums are considered to be waste and can be reclaimed and/or recycled or placed in an offsite landfill for nonexempt waste. The preferred method of disposal of empty drums is reclamation and/or recycling of used drums by retuñing them to the manufacturer or having the manufacturer pick up empty drums for recycling. Disposal options and hazardous waste criteria for RCRA Subtitle C wastes are listed in Appendix B.

3.0 SAFE DRINKING WATER ACT (SDWA)

The Safe Drinking Water Act (SDWA) was enacted by Congress in 1994. Under the SDWA the EPA promulgated regulations for oil field underground injection wells in the underground injection control (UIC) program. The UIC program established Class II injection wells for disposing fluids related to hydrocarbon production. These fluids are:

- Fluids brought to the surface in oil and gas production
- Commingled waste waters from gas plants (if not hazardous at the time of injection)
- Fluids injected for enhanced recovery

UIC regulations require that the regulations should not impede hydrocarbon production unless necessary for the protection of underground sources of drinking water (USDWs). A USDW is an aquifer that either

- Supplies water for human consumption or for any public water system, or
- Meets the following three conditions:
  - Contains fewer than 10,000 milligrams per liter (mg/L) TDS
  - Does not contain minerals or hydrocarbons that are commercially producible

- Is situated at a depth or location that makes potable water recovery economically or technologically practical

The EPA administers the Class II program in states that have not achieved primacy. These are direct implementation (DI) states. Those states that have achieved primacy administer their own programs. UIC programs on Native American lands are administered by the EPA. States with primacy have negotiated primacy with the EPA by demonstrating that their program is at least as stringent as EPA standards. In return for meeting these standards, the states receive funding for implementing of their Class II programs. Primacy agreements may be amended with the approval from the EPA, dictating what can be injected into Class II wells. The EPA directs which fluids can be injected into Class II wells in DI states. Table 3–1 shows hydrocarbon-producing states that have achieved primacy and DI states under EPA administration for the Class II injection program. The EPA has a violation code for DI states and Native American lands that is used for issuing citations to oil and gas operators who are not in compliance with Class II injection program regulations. This violation code is shown in Table 3–2.

Significant Minimum Requirements for Class II Wells (API)

- Only approved exploration and production wastes may be injected.
- No well may endanger USDWs
- Unless permitted by rule, all wells must be permitted before construction.
- All wells must periodically demonstrate mechanical integrity. Mechanical integrity is defined by the EPA as "no significant leak in the casing, tubing and packer and no *significant fluid* movement into an USDW through vertical channels adjacent to the injection wellbore."

—*API*

Table 3–1 Underground Injection Control Class II Program (EPA)

PRIMACY STATES			DIRECT IMPLEMENTATION STATES
Alabama	Louisiana	Ohio	Arizona
Alaska	Michigan	Oklahoma	Florida
Arkansas	Mississippi	South Dakota	Kentucky
California	Missouri	Texas	New York
Colorado	Nebraska	Utah	Pennsylvania
Illinois	Nevada	West Virginia	Tennessee
Indiana	New Mexico	Wyoming	Montana
Kansas	North Dakota		

Table 3–2 Listing of New Compliance Violation Codes (EPA)

VIOLATION CODE	DESCRIPTION AND REGULATION REFERENCE
A	Unauthorized injection - 147.2903(a), 147.2920(e)
B	Possible contamination of USDW - 147.1903(b)
C	Annular injection - 147.2903(c)
D	Failure to conduct required corrective action - 147.2914, 147.2923
E	Failure to apply for a permit when required - 147.2915
F	Fail to conduct a mechanical integrity test - 147.2912(a), 147.2920(b)
G	Mechanical integrity test failure - (casing, tubing, packer) - 14.2912(a)(1), 147.2920(b)(1)
H	Mechanical integrity test failure - (fluid movement) - 147.2912(a)(2), 147.2910(b)(2)
I	Failure to construct well according to permit or rule - 147.2911, 147.2919
J	Failure to inject through tubing or a packer - 137.2920(a)
K	Failure to submit required operating report - 147.2913(b), 147.2922(b)
L	Failure to submit inventory information - 147.2913(a)
M	Failure to conduct required monitoring - 147.2913(b), 147.2922(b)
N	Failure to report change of ownership - 147.2926, 147.2922(e)
O	Falsifying information on report or permit application - 147.2928
P	Failure to report possible USDW endangerment - 147.2912(c), 147.2922(c)
Q	Injection pressure exceeds authorized maximum - 147.2912(b), 147.2925(a), 147.2920(c)
R	Injection rate exceeds authorized maximum - 147.2925(a)
S	Failure to retain records - 147.2913(e), 147.2922(d)
T	Failure to meet compliance schedule - 147.2911, 147.2921
U	Failure to properly plug and abandon - 147.2905(b)(e)
V	Failure to submit plugging and abandonment plan - 147.2905(c)
W	Failure to submit plugging report to BIA - 147.2905(i)
X	Failure to report cessation of operations - 147.2925
Y	Failure to comply with standard permit conditions - 147.2925
Z	Inadequate or no proof of financial responsibility - 147.2905(j)

These compliance codes are from the EPA. Other violations may be added by using the suffixes shown in Table 3–3.

Numbers shown in Table 3–3 are used as suffixes to the primary violation codes listed in Table 3–2. For example, the violation code "G1" is used to show that the operator was required to cease injection because of a mechanical-integrity field-test failure. The suffixes are used to more accurately define the violation or action required and as enforcement codes.

Table 3–3 Suffixes for Primary Violation Codes

SUFFIX	DESCRIPTION
0	Other
1	Cease injection because of violation type
2	Apply for permit because of violation type
3	Compliance schedule after meeting for violation type
4	Compliance schedule in response to letter for violation type
5	Notice of UIC program requirement for violation type
6	Permit condition violation of violation type
7	Failure to comply with code for violation type
8	Undefined
9	Undefined

An American Society for Testing and Materials (ASTM) subcommittee is working on recommended construction requirements for Class II injection wells. This subcommittee was formed during 1993 and is made up of representatives of the EPA, United States Department of Energy (DOE), environmental interests, API, and the hydrocarbon industry. The new Class II injection well construction standards will be adopted in the near future. The EPA is not obligated to adopt ASTM Class II injection well standards, but they will probably consider them since they are involved in the committee. The ASTM subcommittee has been meeting each year at the semiannual meetings of the Groundwater Protection Council (GWPC) in addition to ASTM meetings. GWPC, formerly the Underground Injection Practices Council (UIPC), is an organization of representatives of primacy state regulators for all types of injection wells, with EPA and the DOE as voting members and hydrocarbon industry and other injection industry representatives as nonvoting members. GWPC has headquarters in Oklahoma City, Oklahoma, meets twice a year, and keeps all members up to date on trends and upcoming changes in injection well regulations.

On June 6, 1991, the EPA chartered a Class II Injection Well Advisory Committee that subsequently had seven two-day meetings. The committee was made up of representatives of major and independent oil production companies, environmental interests, state regulators, EPA, DOE, and the United States Department of Interior. The final document of this committee was issued on March 23, 1992.

Final Document

The committee was charged with the task of providing recommendations to the office of Ground Water and Drinking Water regarding possible changes in the Underground Injection Control Program. Over the course of its deliberations, the Committee developed proposals for changes in the following areas: construction requirement, monitoring and testing requirements, "area of review" requirements, abandoned well protocols, actions pursuant to a failure of mechanical integrity, and requirements for commercial disposal facilities. These recommendations are set forth below.

The committee believes that the implementation of these recommendations will substantially increase the overall effectiveness of the Class II program. Specifically, these recommendations address the concerns raised about the adequacy of the UIC program during the Mid-Course Evaluation of the Class II Program in the General Accounting Office Report [which focuses on the current Area of Review (AOR) program], and—with respect to construction requirements for Class II wells—the Report to Congress prepared by EPA/OSW.

Except as noted in the Committee Members' Letters of Endorsement, the committee endorses the recommendations as appropriate Federal requirements for the effective protection of Underground Sources of Drinking Water (USDWs). At the same time, the Committee recognizes that Section 1425 of the Safe Drinking Water Act provides that States may employ alternative requirements if they can demonstrate to United States Enviornmental Protection Agency that, in light of any amendments to the Federal requirements, their programs remain effective in protecting USDWs.

The committee also recognizes that some of its recommendations will place additional administrative burdens on the State programs. In particular the proposed AOR program may necessitate a short-term funding increase for some states if it is to be fully implemented within the recommended time frame.

CONSTRUCTION REQUIREMENTS FOR NEWLY DRILLED WELLS

1. The regulations should be amended to require that all newly drilled wells be constructed with:

2. tubing and packer,

3. long string casing cemented to prevent fluid movement out of the injection zone,

continued

4. cemented surface casing to 3,000 TDS (mg/L-TDS), unless state requirements for surface casing are currently more stringent (in which case these requirements remain in effect) or cementing surface casing to this depth is technically impractical. Where cementing surface casing to 3,000 TDS is technically impractical:

5. it must extend at a minimum to below currently-used water and any water which may reasonably be expected to be used in the future, and

6. cement must be used to isolate the base of 3,000 TDS water.

CONSTRUCTION REQUIREMENTS FOR NEWLY CONVERTED WELLS

7. The regulations should be amended to apply the construction requirements set forth in #1 - #6 above to all converted production wells that are originally constructed after the date these regulations are promulgated.

HISTORICALLY ACCEPTED NON-CONVENTIONAL COMPLETIONS

8. The requirements set forth in #1 - #7 above could be delayed for a maximum of five years for small entities, as defined by the Regulatory Flexibility Act, in those parts of the country where alternative practices have historically been allowed.

MONITORING AND TESTING

9. As is currently required, an mechanical integrity test (MIT) must be conducted every 5 years on wells with three layers of protection and surface casing down to at least 3,000 TDS. For wells with less protection, the regulations should be amended to require:

10. for wells with two layers of protection, an MIT must be conducted at least every three years, and

11. for wells with only one layer of protection, an MIT must be conducted annually.

The regulations should be amended to require that:

12. An AOR be performed within five years of promulgation of the regulations on all existing injection wells except those covered by previously conducted AORs and those located in a field, basin, or project that has been granted a variance as described below.

continued

13. Program directors have six months from the promulgation of the new regulations to provide EPA with:

14. a schedule for performing AORs in known high risk areas within two years, and either

15. a schedule for performing AORs within five years on all wells not covered by previously conducted AORs, or

16. notice of their intent to establish a variance program.

17. The schedule set forth in #14 and #15 may be adjusted by the Administrator for good cause.

18. Program Directors choosing to establish a variance program would have one year from promulgation of the new regulations to submit to EPA for approval a variance plan which set forth the specific types and sources of information that will be considered in making variance determinations.

19. Variances for new and existing wells may be granted only if the Director determines that there is a sufficiently low risk of upward fluid movement from the injection zone that could endanger USDWs.

20. Information indicating any of the following conditions could be considered by a Director in determining whether to grant a variance:

21. the absence of USDWs,

22. the reservoir is under pressured relative to the USDW,

23. local geological conditions preclude upward fluid movement that could endanger USDWs.

24. other compelling evidence.

25. Directors must provide notice and opportunity for public comment in the development of the variance program plan and in the granting of variances.

continued

GUIDANCES

26. The January 22, 1992 draft of Guidance #75, entitled "Follow-up to Class II Well MIT Failures under Section 40 CFR 146.8," should be signed and implemented, and the regulations should be amended as necessary for the effective implementation of the guidance.

27. The January 22, 1992 draft of Guidance #76, entitled "Operating, Monitoring and Reporting Requirements for Class II Commercial Salt Waste Disposal Wells," should be signed and implemented, and the regulations should be amended as necessary for the effective implementation of the guidance.

28. The January 22, 1992 draft of Guidance #77, entitled "Management and Monitoring Requirements for Class II Wells in Temporary Abandoned Status," should be signed and implemented.

—EPA Class II Interjection
Well Advisory Committee
March 23, 1992

The findings and recommendations of the EPA Class II Injection Well Advisory Committee are expected to become regulations in late 1994 or early 1995. They have gone through the comment and review stages and are in the final stages of these recommendations becoming regulations.

The API Environmental Guidance Document has a section on exploration, drilling, and production wastes that can be disposed of in Class II injection wells. This document is currently being revised. Disposal options for wastes that can be injected into Class II wells are shown in Appendix B.

3.1 Waste Disposal Options Under the Safe Drinking Water Act

Waste disposal under the Safe Drinking Waste Act may range from disposing of the waste in Class II injection wells to disposal of materials as hazardous waste. Liquid wastes such as produced salt water, weighted water, and water-based mud may be disposed of by underground injection. A general rule of thumb that can be used for injection into Class II injection wells is if the liquid has come in contact with the formation and oil, it can be disposed of in a Class II injection well. But before indiscriminately disposing of fluids that may be classified as hazardous, an operator should check to see if the substance can pass hazardous waste criteria and the mixture rule to be classified as a nonhazardous waste. Liquid waste that is ignitable, corrosive, reactive, toxic, listed waste, or mixed with hazardous waste must be disposed of as a hazardous substance and can not be injected into a Class II injection well used for produced salt water disposal. Appendix B lists some disposal options and criteria for classification of waste as hazardous. Liquid wastes generated by hydrocarbon exploration and production operations that can be disposed of in Class II injection wells on the operator's lease help to keep operating cost within reason and keep leases clean without contamination. Injection of hazardous wastes into Class II injection wells is prohibited, but hazardous waste can be injected into Class I injection wells.

Operators are also required to protect groundwater from becoming contaminated as a result of drilling for hydrocarbons, production of hydrocarbons, and injection of produced salt water into Class II injection wells. Therefore, groundwater is protected by cementing casing through all potable water zones and demonstrating that there is a good cement bond for protection from movement of produced salt water behind casing into potable water zones. Operators are also required to perform mechanical integrity tests on Class II injection wells every five years to demonstrate that there are no leaks in the casing and that there is no movement of injected salt water behind casing.

4.0 CLEAN WATER ACT (CWA)

The Clean Water Act (CWA) was enacted by Congress in 1972 primarily for the control of point-source discharges of waste into waters of the United States. All point-source discharges of waste are required by law to have NPDES or state equivalent permits. Discharges of produced water, drilling mud, cooling water, spent acid water, glycol, amine, caustic wash, etc., are examples of point-source discharges. Permits for point-source discharges require monitoring and reporting discharges of effluent conditions. Generally, the NPDES permit specified the technology-based limits for concentration of the discharge, which is based on water quality.

Under Section 311 of CWA, discharges of oil into surface waters must be reported to the Coast Guard National Response Center in Washington, D.C. If operators do not report oil spills, they are subject to fines and penalties. In 1973 the EPA promulgated the Oil Pollution Prevention Regulations (40 CFR Part 112) to mitigate the impacts of accidental spills on surface waters.

Operators are required to prepare Spill Prevention Control and Countermeasure (SPCC) plans for nontransportation-related facilities where spills may potentially enter state surface waters onshore and offshore. Facilities are required to prepare an SPCC plan if they have an oil storage capacity of:

- 660 gallons in a single tank
- Collectively, 1,320 gallons or more aboveground
- Collectively, 42,000 gallons or more underground

The SPCC plan sets minimum standards for design and operation of certain aspects of a facility.

40 CFR Part 112.7 contains the guidelines for preparing and implementing an SPCC plan for the prevention and control of an oil spill. The regulations require that an SPCC plan be prepared within six months after a facility begins operation, that the plan be implemented within one year after operations begin, and that the SPCC plan be reviewed and certified by a registered professional engineer every three years. If equipment called for in the guidelines is not practicable for an installation, a strong contingency plan following the provisions in 40 CFR Part 109 must be prepared.

4.1 Operations Affected by the Clean Water Act

Hydrocarbon exploration, production, processing, and refining operations are affected by the Clean Water Act. The primary concern in contaminating streams with accidental oil and/or chemical spills. Therefore, a SPCC plan is required at facilities where large quantities of oil and/or chemicals are stored. In drilling operations, drilling mud from pits, particularly oil-based mud, can be spilled; the possibility of a blowout while drilling requires a written SPCC plan on site to contain any spill. In production operations, the aboveground tanks that usually contain quantities of 100 bbl and more of produced oil and salt water and the pipelines carrying oil from the wellhead to the tanks may break causing spills, requiring an engineer-approved SPCC plan for the producing facility to contain any spill that might occur. Likewise, refining and processing operations have transmission lines and storage tanks that contain oil that can be spilled, requiring an engineer-approved SPCC plan for the facility. Oil spills into navigable streams are expensive to contain and remediate. Therefore, operators must strive to contain spills through prudent monitoring and updating of their SPCC plan as productions change and equipment ages on leases. The chances are good that a small operator with production operations will never have a spill that get into a navigable stream, but an SPCC plan certified by a registered engineer is required for each producing facility. Preparation of this plan by a registered engineer adds to operating costs. Operators are responsible for remediation of spills that occur as a direct result of their exploration, production, processing, or refining operations.

5.0 COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT (CERCLA)

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) was passed by Congress in December 1980. CERCLA is commonly known as Superfund. Congress established the Superfund Program:

- To identify sites where hazardous substances have been released into the environment or where they might occur
- To ensure that sites where releases of hazardous substances have occurred are cleaned up by responsible parties or the government
- To evaluate damages to natural resources
- To create a claims procedure for parties who have cleaned up contaminated sites or spent money to restore natural resources

Releases of hazardous materials above the reportable quantity must be reported to the Coast Guard Response Center. CERCLA gives the EPA broad enforcement authority to require potentially responsible parties (PRPs) to clean up sites contaminated with hazardous materials under Section 106 or to recover costs from PRPs incurred in remediating contaminated sites under Section 107. CERCLA requires that releases of all extremely hazardous substances be reported (without regard to boundaries) to the National Response Center in Washington, D.C., by calling 1-800-424-8802. By calling this emergency response number and following the proper format, an owner/operator will meet the reporting requirements.

When enacted, CERCLA did not exclude previous legal or illegal waste disposal practices from coverage under the statute. Courts have ruled that the statute is retroactive in its applications, that it provides for strict liability without regard to fault, and under appropriate circumstances, it may impose joint and several liability upon responsible parties. Operators have an economic incentive under CERCLA to manage solid wastes properly and to avoid mixing hazardous and nonhazardous wastes in their exploration, drilling, and production operations because of the liability imposed. The EPA has taken the position that nonpetroleum "special wastes" exempt from RCRA Subtitle C hazardous waste regulations may result in CERCLA liability if any of the constituents are "hazardous substances" as listed under CERCLA.

Petroleum, including crude oil or any fraction of crude oil, has an exclusion under CERCLA by the definition of hazardous substance, pollutant, or contaminant. The EPA interpretation of this exclusion includes, in their entirety, *pure petroleum* and *pure petroleum fractions*, even though they contain fractions listed as hazardous substances. Therefore, petroleum is crude oil, crude oil fractions, and refined products, such as gasoline, including any indigenous hazardous substances.

Format for Reporting Hazardous Substance Release

Supply your name, address, telephone number, and name company.

Name of facility and its location.

Name of the chemical released.

Estimate the quantity released (in pounds if possible).

Time release commenced and its duration.

Medium into which release occurred — air, water, soil.

Number of persons (if any) exposed and emergency first aid or medical attention provided.

Known acute or chronic health risk associated with release.

Precautions taken or to be taken to limit exposure.

Name and telephone number of person(s) to contact for additional information.

—*Oklahoma Independent Producers Association*

The following quote is from an article in *The Bureau of National Affairs* of on August 20, 1993, concerning a 1993 United States Ninth Circuit Court of Appeals decision on discarded tank-bottom sediment.

Chrysene is defined by *Webster's Third New International Dictionary* as "a white crystalline hydrocarbon $C_{18}H_{12}$ with violet fluorescence obtained from coal-tar fractions and from petroleum by cracking and prepared from indene by catalytic dehydrogeneration: 1,2-benzo-phenanthrene." With the ruling that tank-bottom sediments are hazardous substance because of the chemical(s) contained in them, this could have wide-ranging impacts on operators of all sizes in the hydrocarbon industry.

No CERCLA Exclusion for Oil Wastes from Tank Bottoms, Ninth Circuit Says

The waste from crude oil tank bottoms is not covered by the petroleum exclusion in the federal superfund law, a federal appeals court ruled Aug. 11 (Cose v. Getty Oil Co., CA 9, No. 91-16575, 8/11/93).

The U.S. Court of Appeals for the Ninth Circuit reversed a district court ruling that discarded tank-bottom sediment with high concentrations of chrysene, a known carcinogen, is excluded from the list of hazardous substances that may trigger cleanup liability under the Comprehensive Environmental Response, Compensation, and Liability Act.

The appeals court ruled Getty Oil may be held liable for cleanup costs for waste drained from tank bottoms and dumped in a gravel pit in Tracy, Calif. When Don A. Cose bought the property containing the pit in 1974, six years after Getty closed its nearby pumping station, he alleged that a layer of top-soil covered the crude oil material. Cose discovered "a subsurface asphalt or tar-like material" in 1987 when he attempted to develop the property for housing.

CERCLA expressly excludes petroleum and crude oil from its definition of a hazardous substance. Getty Oil argued that crude oil tank bottoms are components or fractions of crude oil. Therefore, Getty said, the tank bottoms fall within the petroleum exception.

The U.S. District Court for the Eastern District of California agreed. In September 1991, it said that "the concentrations of various individual chemical constituents, even though exempt because they naturally occur in petroleum, are not found on the property in higher concentrations than in the petroleum itself" (34 ERC 1208; 22ER 1352).

"Clearly Waste," Appeals Court Decides

But the appeals court ruled the tank-bottom material is not within the exclusion because it is a discarded waste product.

Crude oil tank bottoms are made up of sedimentary solids that settle out of crude oil and fall to the bottom of storage tanks, the court said.

"Such tank bottoms accumulate naturally before the crude oil even reaches the refinery," the court said. "Crude oil tank bottoms are not 'one of several portions separable by fractionation' of crude oil, as required by our definition of fraction."

The court concluded the tank-bottom substance was "clearly waste" material.

continued

"Getty Oil disposed of the tank bottom material with no intention of recycling such materials," the court said. "Hence, the 'waste vs. recyclable' distinction further supports a conclusion that crude oil tank bottoms are not a fraction of crude oil and that the tank bottoms therefore do not fall within CERCLA's petroleum exclusion."

In a footnote to its opinion, the court said congress intended the petroleum exclusion to protect "useful" products only. The tank-bottom material is not used for producing useful products, "rather, as evidenced at the gravel pit property, the substance is simply discarded waste," the court said.

Because the court concluded the crude oil tank bottoms fell outside the petroleum exception, the chrysene contaminating the area near the gravel pit "is properly viewed as an independent 'hazardous substance,' rather than a component of petroleum," the court said.

CERCLA liability is imposed regardless of the concentration of hazardous substances in the defendant's waste, as long as the contaminants are "hazardous substances" under the act, the congress said.

Cose (owner of the property) need only show the presence of chrysene to recover cleanup costs under CERCLA Section 1078(a)(3), the court said.

"Because of the presence of chrysene in the gravel pit is undisputed, we reverse the district court's grant of summary judgment and find Getty Oil liable for cleanup costs as a matter of law," the court concluded.

—*Bureau of National Affairs*
August 20, 1993

5.1 CERCLA Compliance in Hydrocarbon Exploration and Production Operations

RCRA-exempt wastes generated in exploration and production operations may be considered hazardous substances, not as exempt under CERCLA. In the previous section, a Ninth Circuit Court of Appeals decision that declared tank bottoms nonexempt under CERCLA is an example of a RCRA-exempt waste becoming a hazardous substance because of the chemical composition and the intent to dispose of the tank bottoms as waste. Waste solvents, motor oil, hydraulic oil, unused acid and stimulating fluid, asbestos insulation, polychlorinated biphenyls (PCBs), etc., are examples of hazardous substances under CERCLA that must be disposed as hazardous in an EPA-approved site or reclaimed and/or recycled. Soil contaminated by produced salt water and/or produced crude oil can also contaminate surface and/or groundwater, causing the site to become a superfund site requiring expensive site investigations, remedial investigation/feasibility studies, approval of remediation technology by the EPA, and lengthy and expensive remediation of the site. Produced salt water contamination of groundwater can be both expensive and lengthy to remediate back to potable water conditions (< 10,000 ppm TDS). The common technology for remediation of contaminated groundwater is pump and treat or pump and disposal of the salt water–contaminated groundwater. Motor oil, changed from engines on drilling rigs, must be disposed of by recycling/reclamation or as a hazardous substance; it can no longer be dumped out on the ground. The EPA and state environmental compliance agencies are requiring operators of compressor stations to remediate sites where used compressor oil has been spilled or leaked onto the ground. Many operators remediate these sites by land farming using mixed commercial fertilizer, water, and a tiller to allow aeration of the soil and increase microbial action for remediating of the oil spill. This is a relatively fast and inexpensive remediation technology. Any exempt waste under RCRA can become a CERCLA waste if it is mixed with a hazardous waste, hazardous substance, or RCRA nonexempt waste. This mixture must then be treated and disposed of as hazardous if it tests hazardous. Appendix B lists some disposal options.

6.0 SUPERFUND AMENDMENTS AND REAUTHORIZATION ACT (SARA)

Superfund Amendments and Reautherization Act (SARA) was enacted by Congress in October 1986. It is a free-standing law and an extension of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980. Subtitle III is the portion of primary concern to operators in hydrocarbon exploration, drilling, and production. SARA is best known in industry for SARA Title III, better known as the Community Right-To-Know Law. The EPA administers and performs oversite of SARA.

Sections 301–303 deal with emergency planning reporting. Section 301 Subtitle A provides for the establishing State Emergency Response Commissions. Emergency response committees formed by these state commissions must at least have representatives from elected state and local officials; law enforcement, civil defense, fire fighting, first aid, health, local environmental, hospital, and transportation personnel; broadcast and print media; community groups; and owners and operators of facilities subject to requirements of Title III. Generally the committee provides public notification activities connected with emergency planning, public meetings to discuss these plans, public comments, response to such comments by the committee, and distribution of the emergency plan. Local Emergency Planning Committees (LEPCs) may be established under the State Emergency Response Commission.

Section 302 of Subtitle A provides a list of extremely hazardous substances (EHS) and their threshold planning quantities upon which notification must be given to the state Hazardous Materials Emergency Response Commission and the LEPC no later than 60 days after a facility begins to handle them. The EPA published a complete list of extremely hazardous substances along with a threshold planning quantity (TPQ) and a reportable quantity (RQ) in the *Federal Register*, Volume 52, Number 77, on April 22, 1987.

Section 303 establishes requirements for owners/operators to appoint a facility emergency response coordinator. The LEPC must be notified of the name of the facility emergency response coordinator within 30 days of the facility becoming subject to requirements of SARA Title III. In general, a facility is defined as all buildings, equipment, structures, and other stationary items which are located on a site or on contiguous or adjacent sites and which are owned or operated by the same person (or by any person who controls, is controlled by, or under common control with such person). The petroleum industry is included because the definition of a facility has been expanded to include a field or part of a field. Small operators may have an advantage in being able to claim a tank battery as a facility. A coordinator may coordinate emergency response at more than one facility. An entire waterflood operation may be listed as a single facility, if it meets the above requirements concerning common control continuity.

Section 304 of Subtitle A established requirements for reporting releases of extremely hazardous substances to air, water, or soil, at or above the RQ. When the release extends beyond the boundaries of the facility, the owner/operator must report the event to the Hazardous Materials Emergency Response Commission and the LEPC.

Hazardous substances under SARA overlap with OSHA's Hazardous Communications (HAZCOM) standard. A hazardous chemical is any element, chemical compound, or mixture of elements and/or compound that is a physical or health hazard. Under HAZCOM, all hazardous chemicals or products require a material safety data sheet (MSDS) to be on file. SARA Title III has several reporting exemptions, such as "household products." In exploration, drilling, and production operations, this exemption applies to those substances at a facility in the same concentration and packaging form as the consumer product used by the general public.

Definition of Hazardous Categories

- Immediate (acute) health hazard
- Delayed (chronic) health hazard, including carcinogens
- Fire hazard
- Sudden-release-of-pressure hazard, including explosives and compressed gasses
- Reactivity hazard

—Oklahoma Independent Producers Association

Section 311 of SARA Title III requires operators to submit MSDSs to the Hazardous Material Emergency Response Commission, the Local Emergency Planning Committee, and the fire department having jurisdiction upon determination that there are 10,000 pounds or more of hazardous chemical or 500 pounds (55 gallons) TPQ or more of an extremely hazardous substance present at any one of an operator's facilities.

Crude Oil Specifics

CRUDE OIL AND NATURAL GAS are defined as hazardous in the HAZCOM Standard (OSHA), this should help avoid confusion. CRUDE OIL API gravity exceeding 20° exhibit a flash point below 200°F, qualify as hazardous chemicals. Therefore, CRUDE OIL at any one tank battery in excess of 10,000 pounds (approximately 30 barrels) triggers the reporting requirement under this section of the law.

—Oklahoma Independent Producers Association
SARA Title III, and OSHA's HAZCOM standards

Because natural gas is not held in storage and weighs less than crude oil, it does not qualify as a triggering mechanism for reporting, although it is defined as hazardous.

Anticipating difficulties in complying with reporting quantities of crude oil, API, the Independent Petroleum Association of America (IPAA), and others devised a generic reporting approach that could satisfy Sections 311 and 312 reporting requirements and would be more beneficial to emergency response agencies. The EPA has agreed that the generic concept can meet requirements under these sections. An API-IPAA guidance document covers these generic reporting methods. Independent producers' associations in hydrocarbon-producing states have environmental guidance documents that also cover SARA Title III Sections 311 and 312 reporting.

6.1 SARA Compliance in Hydrocarbon Exploration and Production Operations

SARA provides for tracking of chemicals used in production operations. Operators must maintain a "paper trail" for chemicals and their containers used for any purpose on their leases. There are EPA-approved forms that operators may purchase and use for tracking chemicals, pesticides, herbicides, etc. used on their leases. Operators are also required to keep up-to-date MSDSs for chemical and/or hazardous substances used on their leases. All of an operator's employees are to be aware of the location of MSDS sheets, the hazards that each chemical imposes, procedure for containment and cleanup in case of a spill, and measures to be taken when exposed to these chemicals. It is important for all company employees and employees of contractors in drilling, production, processing, and refining operations to be aware of emergency procedures in case of a blowout while drilling, a chemical spill, or an oil spill. The operator should have a designated commander to coordinate reporting, containment, and cleanup of a spill. Under SARA, crude oil is defined as hazardous using the HAZCOM definition, but operators are not required to report quantities of oil in storage. Operators should be aware that the EPA can require them to comply with this regulation even though stored quantities of crude oil vary widely on a daily basis.

When acidizing a well for whatever purpose, operators should maintain MSDS sheets on location, have an emergency plan, a SPCC plan, and company personnel trained in case of an accidental spill. Processing plant operators should also follow these same procedures in case of glycol, amine, or caustic wash spills at these facilities. An operator should also have a plan for disposing of excess acid that is not used in acid stimulation operations because the service company usually will not take the excess acid back to their yard and return it to stock. Some options for disposal of excess acid are to have a plan that calls for acidizing another well, acidizing a Class II injection well, or disposal in a Class I hazardous waste injection well. Disposal of acid by injection into a Class I injection well is probably the most expensive disposal method. Whatever the disposal method is, a plan should be in place on location and on file in the office for the final disposal disposition of excess chemicals to satisfy EPA inspectors in case of an audit. An accidental spill can draw EPA inspection for audit of an operator. Therefore, it is important for operators to maintain a paper trail of chemicals used in all operations, as well as emergency plans, disposal plans, MSDS sheets, and trained personnel.

7.0 CLEAN AIR ACT (CAA)

The Clean Air Act (CAA) was enacted in 1970 and amended in 1977 and 1990. The 1990 amendment to the CAA gives the federal government and states new authority to require operators to install pollution control equipment to reduce emissions, to obtain emission permits, and to perform air monitoring to further reduce emissions. Seven titles or sections were created when Congress amended the CAA in 1990.

Sections of CAA as Amended

- Title I - Non-attainment
- Title II - Mobile Sources
- Title III - Air Toxics
- Title IV - Acid Rain
- Title V - Permits
- Title VI - Ozone Depleting Substances
- Title VII - Enforcement

—*Texas Independent Producers and Royalty Association*

Titles III, V, and VII affect operations in the hydrocarbon industry. EPA regulations regarding the CAA are implemented by states through state implementation plans (SIPs). States write implementation plans that are then submitted to the EPA for approval. SIPs must be at least as stringent or more stringent than EPA regulations under the CAA to be approved. After SIPs are approved, they may then be enforced by either the state or the EPA.

Under the 1990 amendment to the CAA, Title III, Air Toxics, established a list of 189 hazardous air pollutants (HAPs) that must be addressed by the new air toxics program. Benzene is one of several pollutants common in the hydrocarbon-producing industry that was on this list, but hydrogen sulfide is not on the list. The amendment requires the EPA to develop and publish a list of categories and subcategories of major sources and area sources of hazardous air pollutants that will be regulated.

Major source is defined as "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit[,] considering controls, in the aggregate, 10 tons per year (tpy) or more of any hazardous air pollutant or 25 tpy or more any combination of hazardous air pollutants." Stationary source is defined as "any building structure, facility or installation which emits or may emit any air pollutant."

In determining whether a facility is a major source, an operator must consider each oil and/or gas well individually rather than as a field as an aggregate across a commonly operated area under contiguous control. Equipment associated with production facilities—pipeline compressor, pump stations, steam generators, etc.—are to be evaluated separately. Most oil and/or gas production facilities are believed to be exempt from the air toxics portion of the CAA amendment of 1990 because they are thought to emit <10 tpy of any individual HAP and <25 tpy of a combination HAPs. Once a source is determined to be a major source of one pollutant, it must address all applicable requirements for all regulated pollutants. This may include monitoring and reporting of emissions from the facility.

The quantity of benzene emitted from storage tank vents and the size of oil storage tanks may cause a storage facility to be considered a major source. Natural gas processing plants, compressor stations, and gas storage facilities may be affected by the 1990 CAA amendment if they fall under the definition of a major source. This CAA amendment gave EPA the authority to establish more stringent control for facilities located in metropolitan areas with populations exceeding 1 million.

Under the 1990 CAA Amendment, Title V, Permits, has a comprehensive new program requiring sources of air pollutants to obtain operating permits and requires states to administer the permit program. Major sources that emit or have the potential to emit 100 tpy of any regulated pollutant are required to obtain a permit. Stationary and area sources that emit or have the potential to emit specific hazardous pollutants may also be required to obtain a permit. In nonattainment areas additional sources can be required to obtain a permit. A nonattainment area is identified by the EPA as having high levels of air pollutants.

Under the 1990 CAA Amendment, Title VII, Enforcement, updated enforcement provisions so that they parallel pollution control enforcement provisions in other acts, such as the CWA. A field citation program is established. It has provisions for citizen suits against sources of air pollution. EPA was also given authority to access administrative penalties.

Both states and the EPA have authority to assess administrative, civil, and criminal penalties against operators of facilities that are emitting pollutants into the atmosphere. Up to $25,000 per day for each violation may be assessed as civil penalty for emitting pollutants. Criminal fines and imprisonment of up to five years are outlined in Title 18 of the United States Code for offenders knowingly emitting pollutants. Administrative penalties of up to $200,000 may be assessed by the EPA. The EPA may award up to $10,000 to any citizen or local government for information or services that lead to a penalty or conviction under the CAA.

7.1 Compliance with the CAA in Hydrocarbon Exploration and Production Operations

Under RCRA, crude oil is an exempt substance, but it loses its exemption by definition under SARA and CAA because benzene, a known pollutant and carcinogen, is a component of crude oil. Oil wells produce crude oil into temporary storage tanks where benzene may be emitted to the air. Operators can be required by EPA under CAA Amendments of 1990 to monitor storage tank emissions and place emission control devices on crude oil storage tanks if they emit <10 tpy of any individual HAP and <25 tpy of a combination HAPs. The EPA can require an operator to monitor crude oil storage tanks or calculate the quantity of benzene or combination of HAPs that are emitted to determine whether emission control and continuous monitoring are required. Enforcement of this part of the 1990 amendments will place additional cost of environmental compliance on operators, particularly those operators that have marginal or stripper production. Gas compression stations will be affected by the 1990 amendments by including compressor engine emissions as stationary sources. Emission control devices will be needed for engines ≥ 450 horsepower, and emissions may need to be monitored as well. Gas plant operators will be required to monitor emissions and to take measures to control emissions. States, through authority granted by the 1990 amendments through the EPA, are required to issue permits to operators that emit air pollutants, require air monitoring, and enforce 1990 amendments. It is conceivable that drilling contractors will be required to install pollution control equipment on their engines on drilling rigs. Emission control and monitoring requirements on operators in production and processing will increase the cost of operating and could lead to plugging and abandonment of some marginal and stripper wells.

8.0 TOXIC SUBSTANCE CONTROL ACT (TSCA)

The Toxic Substance Control Act (TSCA), found in 15 United States Code Part 2601 *et seq.* and 40 CFR Part 700 *et seq.*, was enacted in 1976.

EPA Authorizations per TSCA

- Testing of chemical substances
- To regulate chemical substances and significant new uses of old chemical substances still being manufactured
- To implement record keeping and reporting requirements related to chemical substances, including production, distribution, releases, inventories and adverse health and or environmental effects associated with the substances

—Texas Independent Producers and Royalty Association

TSCA regulates the manufacture, distribution, use, and disposal of certain targeted substances, including PCBs and asbestos. Any spill of greater than 10 pounds of PCBs in a 24-hour period must be reported. Manufacturing facilities, utilities, and other users of PCBs and PCB-containing equipment, such as transformers and capacitors, must conform to certain requirements.

Required Provisions for PCB Users

- Proper identification and marking of equipment
- Perform regular inspections
- Keep records
- Comply with specific storage removal, transportation, and disposal requirements

—Texas Independent Producers and Royalty Association

Under TSCA, a chemical substance is defined as "any organic or inorganic substance of a particular molecular identity, including any combination of such substances occurring in whole or in part as a result of a chemical reaction or occurring in nature, and any element or uncombined radical." It requires EPA to develop an inventory of each chemical substance manufactured, processed, or imported into the United States. Certain substances are excluded from the definition of chemical substance under TSCA.

Substances Excluded from TSCA's Chemical Substance Definition

- Any mixture other than one that occurs in nature or is the result of a chemical reaction,
- Any pesticide manufactured, processed, or distributed in commerce for use as a pesticide,
- Tobacco or any tobacco product (excluding derivative products),
- Any source material, special nuclear material, or byproduct material,
- Any pistol firearm, revolver, shells and cartridges, and
- Any food, food additives, drugs, cosmetic, or device manufactured, processed, or distributed in commerce for such uses.

—Texas Independent Producers and Royalty Association

Manufacturers, importers and processors were required to submit information on chemicals they handle to the EPA in June 1979. This list of chemicals required under TSCA is known as the Toxic Substances Chemical Inventory. Chemicals added to the list after this date must undergo a premanufacturing notification review. Every four years manufacturers and importers must update their inventory and submit it to the EPA. This data submitted to the EPA must contain product volume, plant site, and site-limited status (a chemical is "site-limited" if it is manufactured on site and is not distributed for commercial purposes) for certain chemical substances in the Toxic Chemical Substance Chemical Inventory. The last TSCA inventory update reporting period was August 25 to December 23, 1994.

In general, under TSCA, a person is considered a manufacturer if 10,000 pounds of a substance listed on the inventory at a site is manufactured or imported for commercial purposes. Volume records are required to be maintained to support a manufacturer's determination not to submit a report. In other words, these records must be maintained to prove to the EPA that more than 10,000 pounds have not been manufactured or imported for commercial use.

Some substances generally excluded from the inventory are:

- Polymers
- Inorganic substances
- Microorganisms
- Naturally occurring substances

EPA Examples of Excluded Naturally Occurring Substances (not a complete list):

- Raw agricultural commodities
- Water
- Air
- Natural gas
- Crude oil
- Minerals
- Ores
- Rocks

—*EPA*

Therefore, crude oil, natural gas and other naturally occurring substances are exempt from reporting requirements, although constituents of crude oil and natural gas (benzene, xylene, and toluene) are. Natural gas liquids from natural gas processing plants are required to be reported under the inventory update regulations. But the Texas Independent Producers and Royalty Owners Association (TIPRO) found a conflict between EPA Region 6 in Dallas and EPA Headquarters in Washington on the interpretation of this exemption.

Certain small manufacturers and persons manufacturing limited quantities are exempt from certain reporting and record keeping requirements. If they do not exceed $4 million in sales, small manufacturers are exempt from the reporting requirement under inventory update regulations. Manufacturers and their parent company with sales between $4 million and $40 million may also be exempt from the reporting requirement under the inventory update regulations if the total volume of substances does not exceed 100,000 pounds. In reporting a manufacturer must designate a representative in the company to answer technical questions on the updated inventory. The inventory update must include chemical identity, plant site, annual production volume, and site-limited status of a reportable substance. Manufacturers and persons subject to inventory update must maintain records for a period of four years beginning with the effective date of each reporting period.

Discrepancy Between EPA Region 6 and Headquarters

The Association contacted the Dallas EPA office and the Washington EPA office and received conflicting information on whether certain constituents found in crude oil, such as toluene, benzene, and xylene, are subject to the inventory update regulations. The Dallas EPA office states that as long as these substances make up one percent or less of the crude oil, natural gas, etc., they are considered impurities and are not required to be reported. According to the Dallas office, if these constituents exceed one percent of the product, they are subject to inventory update regulations and must be reported. The Washington EPA office states that as long as the substance is "naturally occurring", it need not be reported. However, the Washington office also stated that if a manufacturer's production volume is less than 10,000 pounds per year, the substances generally would be exempt from the inventory update regulations.

—*Texas Independent Producers and Royalty Owners Association*

8.1 Compliance with TSCA in Hydrocarbon Exploration and Production Operations

Under TSCA, crude oil and natural gas are exempt from reporting quantities produced and stored at facilities. Crude oil in storage contains benzene, toluene, and xylene, which are toxic substances. Therefore, operators could be required by the EPA to report quantities of these constituents of crude oil because there is a conflict between EPA headquarters and Region 6 on whether quantities of these substances should be reported. Crude oil could lose its exclusion under TSCA because it contains these toxic substances. Operators of natural gas processing plants that have natural gas storage are required to report inventory of natural gas liquids stored at the facility because natural gas liquids contain toxic substances. Operators of natural gas liquids plants track and keep records on liquids stored at the facility, but requirements to report these quantities to state environmental compliance authorities and the EPA on additional new forms will place additional cost on operators. Should the EPA decide to require operators to report quantities of benzene, toluene, and xylene in storage tanks on producing leases and at refineries, additional analyses, tracking, and reporting will cause cost of operations to increase. Loss of the exclusion for crude oil will severely impact marginal and stripper operations for small independents and could cause premature abandonment of these wells by operators.

9.0 OIL POLLUTION ACT OF 1990 (OPA)

The Oil Pollution Act of 1990 (OPA) was enacted in response to several large oil spills into navigable waters of the United States. Its intent is to reduce the number of oil spills and to improve the nation's preparedness and ability to respond to spills. A comprehensive prevention, response, and compensation program for oil spills into onshore and offshore navigable waters was created by this act. It was signed into law on August 18, 1990. The EPA has jurisdiction over certain onshore facilities under OPA.

OPA required owners and/or operators of onshore facilities to prepare and submit a facility response plan to the EPA by February 18, 1993. It does not specifically identify facilities covered under the act but, in general, it affects facilities that could cause "substantial harm" to the environment by discharging into navigable waters or on the adjoining shorelines. Response plans to oil spills under OPA are in addition to current SPCC plans under the CWA. EPA will grant a two-year extension from this requirement if owners and/or operators can prove that they are capable of responding to a worst-case discharge from the facility. "The largest foreseeable discharge in adverse weather conditions" is the definition of a worst-case discharge. The OPA specifically prohibits facilities required to have a response plan from handling, storing, or transporting oil after February 18, 1993, unless a plan has been submitted.

The only discharges that are excluded from the OPA are those allowed by permit under federal, state, or local law. Owners and/or operators are not liable if:

Exceptions to Owners/Operators Liability

- The discharge was caused solely be an act of God
- The discharge was caused solely by an act of war
- The discharge was caused solely by the act or omission of a third party

—*Texas Independent Producers and Royalty Association*

If the spill was caused by an employee or an agent of the responsible party or by a person under any contractual relationship with the responsible party, the third-party defense for the spill does not apply. Limited liability of the total of all removal cost plus $75 million for offshore facilities and $350 million for onshore facilities and deepwater ports is established by the OPA.

Through a 5¢/bbl tax on imported and domestic crude oil and crude oil products, a $1 billion fund was established to be used to pay for removal costs and damages not recovered from responsible parties.

The amount of civil penalties, criminal fines, and terms of imprisonment that can be imposed upon owners and/or operators of facilities with discharges of oil are increased substantially. A responsible party with an oil discharge failing to notify the federal government may result in a criminal fine of up to $25,000 for an individual and up to $50,000 for an organization, or not more than five years imprisonment, or both. A criminal fine of not less than $2,500 nor more than $25,000 per day of violation, one year imprisonment, or both may result if a responsible party negligently discharges oil into navigable waters. A second offense of negligible oil discharge into navigable waters may result in a fine of $50,000 per day of violation, or two years imprisonment, or both. In addition to criminal penalties, a responsible party may incur civil penalties of up to $25,000 per day of violation or an amount up to $1,000 per barrel of oil discharged. If the discharge is the result of gross negligence or willful misconduct, a responsible party may be fined not less than $100,000 plus not more than $3,000 per barrel of oil discharged.

Exclusions of Liability Limits

- The spill is caused by willful misconduct or gross negligence,
- The responsible party violates any applicable federal safety, construction or operating regulation,
- The responsible party fails to report an oil spill, or
- A responsible party fails to cooperate with the government.

—Texas Independent Producers and Royalty Association

9.1 Compliance with the OPA in Hydrocarbon Exploration and Production Operations

Under the Oil Pollution Act of 1990, operators are required to submit a facilities response plan for the largest conceivable spill that could get into a navigable stream. This is in addition to the SPCC plan required under the Clean Water Act. This affects virtually all operators because the broad legal definition of navigable stream could include all streams. This law places additional expense on operators in preparation and maintenance of a response plan.

10.0 MIGRATORY BIRD TREATY ACT

The Migratory Bird Treaty Act is found in 16 United States Code Part 703 *et seq.* It prohibits harm to a migratory bird. A list of migratory birds protected by the treaty is found in 50 CFR Part 10. Operators can and have been fined by the U.S. Fish and Wildlife Service when migratory birds are trapped or injured in open oil pits and open-topped tanks. The treaty does not mandate any specific method of protecting or deterring birds from oil production or storage facilities. The Fish and Wildlife Service recommends that operators screen or net facilities that may endanger migratory birds.

The Fish and Wildlife Service is empowered to search facilities, seize evidence necessary for prosecution, and arrest any person committing a violation against the treaty. Responsible parties committing violations may be fined $500 and/or six months in jail for violations of the treaty. The Criminal Fine Improvements Act of 1987 (Public Law 101-185) redefined all criminal fines, including those under the treaty. A violation is a Class B misdemeanor and carries a maximum penalty of $5,000 per bird for individuals and/or six months in jail, and $10,000 per bird for corporations.

10.1 Compliance with the Migratory Bird Treaty Act in Hydrocarbon Exploration and Production Operations

The Migratory Bird Treaty Act can eliminate open pits on producing leases or require operators to place a protective screen over existing pits to keep migratory birds out of open oil or salt water pits. This act will place additional expenses on operators to level open pits and/or maintain screens over open pits. This will affect virtually all operators.

11.0 ENDANGERED SPECIES ACT

The Endangered Species Act, enacted in 1973, is found in 16 United States Code Part 1531 *et seq.* and prohibits the taking of an endangered or threatened species. *Taking* as defined by the act may include habitat modification or destruction that kills or injures protected wildlife by significantly impairing essential behavior patterns such as breeding, feeding or sheltering. Clearing or developing an area that is or has the potential of being the habitat of an endangered or threatened species could be considered a violation of the Endangered Species Act.

Each federal agency is required by the Endangered Species Act to insure that any action authorized, funded, or carried out by the agency will not jeopardize the continued existence of an endangered species or damage or destroy any endangered species' critical habitat. This part of the act applies only to federal agencies, but it can affect nonfederal development authorized or funded by a federal agency. The taking of endangered or threatened species applies to both private and public entities whether federal or state. A landowner may make application to the U.S. Department of Interior for a permit for development that might constitute the taking of an endangered species as long as the taking is incidental to, and not the purpose of, the activity. The permit can be revoked if the terms or conditions of the permit are not being followed.

A responsible party can be assessed a civil penalty of up to $25,000 and a criminal penalty of up to $50,000 and/or imprisonment for up to one year for violation of the Endangered Species Act.

11.1 Compliance with the Endangered Species Act in Hydrocarbon Exploration and Production Operations

The Endangered Species Act affects all operators in hydrocarbon exploration and production. It prohibits destruction of habitat of endangered species and killing endangered species. An operator can be prohibited from drilling in an area where an endangered species has its habitat. It has cost $884 million for plans for recovery of endangered species, and not a single listed species has ever been legitimately delisted as a result of the Endangered Species Act. To date, there have been 306 plans written since the passage of this act. No estimates have been made on the impact to the economy by exclusion of activities as a result of this act. Operators should be aware of the consequences of violation of the act.

12.0 HAZARDOUS MATERIALS TRANSPORTATION ACT (HMTA)

The Hazardous Materials Transportation Act (HMTA) is a DOT regulation affecting hydrocarbon exploration, drilling, and production. It regulates transportation of hazardous waste, PCBs, asbestos, naturally occurring radioactive material (NORM), and other DOT hazardous materials. DOT requires permits for transporting these materials on public roads and highways, and requires the transportation be around rather than through cities.

12.1 Compliance with HMTA in Hydrocarbon Exploration and Production Operations

HMTA affects operators in exploration and production who transport hazardous waste and hazardous materials or have these transported by a contractor. Even though crude oil is exempt under RCRA, it can be considered as hazardous by DOT because it is flammable and some of its constituents (such as benzene, toluene, and xylene) are toxic substances in addition to being flammable. Operators who transport produced salt water, tank bottoms, pit sludge, asbestos, PCBs, NORM, etc., to offsite disposal facilities could be held responsible for at least a share of the cleanup of these material should an accident occur while in transit. Improper disposal of a hazardous waste or hazardous substance by a contract hauler can lead an operator to be considered a responsible party with others in a superfund site under CERCLA. Therefore, operators should take care in selection of contractors that haul hazardous wastes and hazardous substances.

13.0 ECONOMIC IMPACTS OF IMPLEMENTING ENVIRONMENTAL REGULATIONS

A 1990 study performed by EPA and API estimated costs of implementing environmental regulations in hydrocarbon exploration, drilling, and production operations.

Assumptions of EPA and API Study

- 1985 levels of drilling and development would continue
- Increased regulations would not affect industry activities except in adding costs to operations that would be pursued regardless of the increased regulations
- Overall industry expenditures will not necessarily increase because of increased regulations
- Increased environmental regulations could cause some previously economical projects to become uneconomical
- Reduced development of crude oil resources could more than offset the increased cost of environmental compliance
- Overall industry expenditures could decrease as a result of the increased regulatory requirements

—EPA, API

It was estimated that it would cost from $15 to $79 billion initially for industry-wide compliance and approximately $2–$7 billion per year thereafter to comply with increasing environmental regulations.

The study concluded that most hydrocarbon resources would become uneconomical as a result of environmental compliance and that state and federal revenues will decrease as a result of lost revenues due to environmental compliance.

Exploration and development drilling and production have not stayed flat with 1985 levels. The price of domestic crude oil and natural gas fluctuate on the market daily, but the cost of environmental compliance with ever increasing environmental regulation does not decrease.

Table 13–1 gives estimated minimum costs for environmental compliance for regulations, cleanup, and remediation. This is not a complete list and costs, but estimates only. Actual cost of compliance, cleanup, and remediation is contingent on the severity of the problem. Examples of environmental compliance that many operators may consider as "cost of operations" are disposal of produced brine, disposal well construction, maintenance, and testing. These costs vary in different producing regions and with different operators in the same region. Therefore, it is difficult to estimate the cost of environmental compliance. The average well in the United States produces approximately 11 barrels of oil per day (B/D), with total oil production of approximately 7,000,000 B/D. Brine production records are not kept in all oil-producing states. Because of the lack of record keeping for produced brine, it is difficult to estimate the actual total cost of brine disposal in the U.S. oil and gas industry. An estimate of brine production in the U.S. commonly quoted is 50,000,000 B/D (2.1 billion gallons/day). Commercial disposal of this amount of water will cost approximately 50–60¢/bbl, whereas cost of disposal by an operator with a brine disposal well is 10–25¢/bbl. The cost of brine disposal ranges from $1,825,000,000 at 10¢/bbl to $4,562,500,000 at 25¢/bbl. These costs make brine disposal the largest single environmental cost in oil and gas exploration and production operations.

14.0 EXAMPLES OF VIOLATIONS

Research is in progress to determine the number and type of surface violations affecting hydrocarbon exploration, drilling, and production operations. Osage County, Oklahoma, has been selected as the starting point for developing a statistical analysis program for the risk-based analysis research program performed by BDM Oklahoma, Inc., for the Department of Energy (DOE) at the National Institute for Petroleum and Energy Research (NIPER) facility. Minerals in Osage County are owned by the Osage Indian Tribe through the Osage Mineral Reservation Estate administered by the Bureau of Indian Affairs (BIA) at the Osage Agency, Branch of Minerals, in Pawhuska, Oklahoma. Surface environmental violations are investigated and enforced by the Osage Agency. The EPA administers and enforces the Class II Injection Well Program on Native American lands in Osage County. Between June 1993 and June 1994, 136 citations for 352 violations were issued by the Osage Agency to oil and gas operators in Osage County, as shown in Table 14–1. From 1986 through April 1994, the EPA issued citations for 16,905 injection well violations to oil and gas operators in Osage County. Citations for surface violations are minor when compared to violation citations in the Class II Injection Well Program issued by the EPA. The EPA violation code for Class II injection wells is shown in Table 3–2.

Table 13-1 Examples of Environmental Compliance Costs

OPERATION	ESTIMATED COST
Tank-bottom disposal, per tank	$100
Commercial produced-brine pickup, hauling, and disposal, per barrel	$0.50–0.60
Brine disposal on lease, per barrel	$0.10–0.25
Oil cleanup on lease— vacuum truck, per hour	$200
Oil cleanup on lease—hauling and spreading of screenings after cleanup, per load	$50
Damages for saltwater leaks, per leak	$500–1500
Damages payable to land owner, per drilling location	$500–1500
Drilling and completion cost for brine disposal well	$25,000-up
Mechanical integrity testing of brine disposal well	$500
Repair of brine disposal well	$5000-up
Well plugging,per foot of well depth	$1
Well location cleanup after drilling	$500-up
Bioremediation of oil contaminated soil (land farming; depends on size of spill)	$5000-up
Groundwater monitoring wells per well (contingent upon depth to groundwater)	$2500-up
Remediation of brine-contaminated groundwater	>$1,000,000
Remediation of severe oil- and brine-contaminated soil at surface	>$1,000,000

This is not a complete list of environmental compliance costs for drilling, exploration, and production operations. These costs are estimates and may vary for operators depending on environmental conditions and location.

15.0 CONCLUSIONS

Federal environmental regulations are becoming more stringent and have a greater impact on operating costs in hydrocarbon exploration, drilling, and production operations. The Environmental Protection Agency, Occupational Safety and Health Administration, Department of Transportation, and Fish and Wildlife Service have administrative and enforcement authority over environmental regulations and the authority to promulgate environmental regulations and/or to administer and enforce environmental regulations under authority given by law. Regulations under the Clean Air Amendments of 1990 could affect operating costs for small and large operators by requiring reporting, monitoring, and installing pollution control equipment for storage, compression, and pumping facilities.

Class II injection well regulations to be adopted later will affect operating costs for all operators, but small independent operators will probably be affected most because of unstable oil and gas prices and increased cost of environmental regulatory compliance. EPA compliance violation data indicate that Class II injection well violations have the greatest affect on operations. Compared to underground injection control violations in the Class II Injection Well Program, citations for surface violations on leases are relatively minor. Disposal of produced brines in Class II injection wells costs the oil and gas industry from $1,825,000,000 at 10¢/bbl to $4,562,500,000 at 25¢/bbl. Therefore, brine disposal is the single highest environmental compliance cost to operators in hydrocarbon exploration, drilling, and production.

Table 14-1 Surface Violations for Osage County, Oklahoma, June 1993 - May 1994
(BDM-Oklahoma Code number)

VIOLATION CODE*	DESCRIPTION	NUMBER OF VIOLATIONS
001	Leak at well location, conditions are sloppy	33
002	No descriptive signs: _Wells _Tank Battery	49
003	No locking devices at tank	2
004	Equalizer lines need lock stop valve	0
005	Pipelines leaking	9
006	Conditions sloppy at tank battery; clean up	29
007	Pits not leveled or fenced	9
008	Empty pits and level location	4
009	Pit at tank battery not kept empty	36
010	Fence at tank battery needs repairs	15
011	Not confining vehicles to existing roads	16
012	Remove all equipment not necessary to operate lease	63
013	Lease not producing; subject to termination	3
014	Lease roads in need of repair	36
015	Tanks not numbered	4
016	Saltwater tank leaking; repair or replace	3
017	Gates or cattle guards not in proper condition	3
018	Keep oil cans and other trash picked up	34
019	Lease needs equipment moved off for termination	0
020	Location needs leveling	0
021	Wiring needs to be buried	3
022	Other	1
	Total Violations	352

*(BDM-Oklahoma Code number)

Operators need to stay up-to-date on which wastes generated in drilling, production, and processing operations are exempt and what quantities are exempt under the different environmental regulations of various agencies. All operators should be aware of the mixture rule that nonhazardous waste or exempt waste requires disposal as a hazardous waste if an exempt waste or nonhazardous waste is mixed with a hazardous substance, hazardous chemical, hazardous waste, or nonexempt waste. Segregation of waste streams on location is essential to reduce operating costs. The recent decision by the Ninth Circuit Court of Appeals in California concerning disposal of tank-bottom sediments will affect all operators in oil fields across the United States because all must dispose of tank-bottom sediments at their storage tank batteries. All new, more stringent environmental regulations enacted by Congress or promulgated by agencies increase operating costs in an already depressed industry. Giving operators a five-year extension to comply with new regulations may, in effect, cause plugging of marginal wells as production declines, prices remain unstable, and environmental compliance costs increase.

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APPENDICES

APPENDIX A

ENVIRONMENTAL REGULATIONS

The information is this appendix comes from Developing Area-Specific Waste Management Plans for Exploration and Production Operations, an environmental workshop sponsored by American Petroleum Institute, Gas Research Institute, and U.S. Department of Energy, Oklahoma City, Oklahoma, January 1993.

Major Federal Regulations Discussed in this Report

- Resource Conservation and Recovery Act (RCRA)
- Safe Drinking Water Act (SDWA)
- Clean Water Act (CWA)
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- Superfund Amendments and Reauthorization Act (SARA)
- Toxic Substances Control Act (TSCA)
- Hazardous Materials Transportation Act (HMTA)

Resource Conservation And Recovery Act (RCRA)

- Listed hazardous waste
- Characteristics of hazardous waste:
  - Reactivity
  - Corrosivity
  - Ignitibility
  - Toxicity
  - Mixtures
- Test for Characteristic and Nonhazardous

- If tests characteristically hazardous = **Hazardous**

- If tests characteristically nonhazardous = **Nonhazardous**

- Listed and Nonhazardous = **Hazardous**

Safe Drinking Water Act (SDWA)

- It establishes minimum requirements for Class II wells under the underground injection control (UIC) program.

- Only approved exploration and production wastes may be injected.

- No well may endanger USDWs.

- Unless permitted by rule, all wells must be permitted before construction.

- All wells must periodically demonstrate mechanical integrity or meet approved monitoring requirements.

Clean Water Act (CWA)

- Point-source discharges

- NPDES (National Pollutant Discharge Elimination System)

- Nonpoint-source discharges

- Stormwater

- Oil-spill reporting

- SPCC (Spill Prevention Control and Countermeasure) plan

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

- The "Superfund"

- Strict joint and several liability

- Hazardous substance release reporting

Superfund Amendments and Reauthorization Act (SARA), Emergency Planning and Community Right-To-Know Act

- Emergency Planning Report, sections 301–303
- Emergency Release Report, section 304
- Community Right-To-Know Report, sections 311–312
- Tier I—Report volumes by hazard category
- Tier II—Report volumes by individual chemical

Toxic Substance Control Act (TSCA)

- PCB use and disposal
- Suspect hazard reporting system
- Chemical substance inventory
- Asbestos

Hazardous Materials Transportation Act (HMTA), Department Of Transportation (DOT) Regulations

- Hazardous waste
- PCBs
- Asbestos
- Naturally occurring radioactive materials (NORM)
- Other DOT hazardous materials

Other Federal Regulations

- Clean Air Act (CAA)
- Migratory Bird Protection Act (MBPA)

Summary Of Environmental Laws

NEPA	You tell the government what you're going to do before you do it.
SARA	You tell the public what you're doing while you're doing it.
CAA	You can't put it up the stack.
CWA	You can't put it out the pipe.
SDWA	You can't put it in a hole in the ground.
RCRA	You can't put it anywhere else.
CERCLA	You must pay for your "sins of the past."
HMTA	You can't even carry it around.
TSCA	It's such bad news, you shouldn't be in the oil business in the first place; if it's such bad news, you can't even make it in the first place.

Increased Regulation Will Come From:

- EPA regulatory gaps
- RCRA reauthorization

Increased Liability

- Exploration and production exemption is not a shield to liability.
- EPA has expanded hazardous waste definition.
- Statutes other than RCRA may apply.

Cost Efficiencies

- Cheap management methods today may be costly in the future.
- Operators are never released from liability created from the waste they generate.

Environmental Impacts/Benefits

- Pollution prevention
- Waste minimization

- Can significantly reduce your operating costs

Trends

- Increasing environmental awareness
- Increasing fines and jail terms

APPENDIX B

THE EXPLORATION AND PRODUCTION EXEMPTION AND WASTE CLASSIFICATION

The information in this appendix comes from Developing Area-Specific Waste Management Plans for Exploration and Production Operations, an environmental workshop sponsored by American Petroleum Institute, Gas Research Institute, and U.S. Department of Energy, Oklahoma City, Oklahoma, January 1993.

History

Congress recognized the special nature of oil and gas exploration and production (E & P) wastes and exempted them from hazardous waste regulation under RCRA Subtitle C, subject to an EPA study. This study, and the June 1988 Regulatory Determination that followed, concluded the exemption is appropriate and should be continued.

The Exploration and Production Exemption

Drilling fluids, produced water, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are exempt from RCRA Subtitle C.

Hazardous Waste Criteria (RCRA Subtitle C)

- Lists
  - F List: Nonspecific sources
  - K List: Specific sources
  - P List: Acutely hazardous waste
  - U List: Toxic wastes
- Characteristics
  - Ignitibility
  - Corrosivity
  - Reactivity
  - Toxicity Characteristic (TC)

New TC Test: Toxicity Characteristic Leaching Procedure

- Mixture Rule
  - Listed waste and nonhazardous waste = all becomes hazardous
  - Characteristic waste and nonhazardous waste = must test
  - If tests characteristically hazardous = hazardous
  - If tests characteristically nonhazardous = nonhazardous
  - Must keep wastes segregated

Field Production Wastes*

Exempt	Nonexempt
Paraffin	Painting wastes
Heater treater hay	Waste lubricating oils
Waste crude condensate	Sandblast media
Produced water	Empty drums
Backwash	Asbestos insulation
Oil/water contaminated soils	

*Lists of wastes are not complete. These are examples of types of wastes in this category only.

Drilling Operation Waste*

Exempt	Nonexempt
Rigwash fluids	Spent hydraulic fluids
Residual (used) drilling fluids and containers	Paint and pipe dope
Drilling muds and cuttings (used)	Used oil from engines
Excess cement (used)	Gaskets
Empty sacks & drums	
Quarters garbage	
Liners	

*Lists of wastes are not complete. These are examples of types of wastes in this category only.

Completion Workover Wasted*

Exempt	Nonexempt
completion, treatment and stimulation fluids (used)	Spent hydraulic fluids
Produced sand	Used lubricating oils
Cement cuttings (used)	Radioactive tracer wastes
Pipe scale	
Gels (used)	
Muds (used)	
Paraffin solvents and dispersants (used)	

*Lists of wastes are not complete. These are examples of types of wastes in this category only.

Gas Plant Wastes*

Exempt	Nonexempt
Produced water	Engine cooling water
Pigging materials	Used lubricating oils and filters
Inlet filter media	Boiler refractory bricks
Glycol-based fluids	Boiler cleaning wastes
Condensed water	Laboratory wastes
Spent molecular sieve	
Iron sulfide	
Cooling tower blowdown	

*Lists of wastes are not complete. These are examples of types of wastes in this category only.

Disposal Options for Typical Oil and Gas Wastes*

Waste Product	Disposal Option
Produced water	6, 7, 9
Weighted water	6, 7
Spent acid	6, 7
Water-base mud	1, 2, 6, 7, 8
Water-base mud cuttings	2, 5, 6, 8
Oil-base mud	1, 2, 5, 7
Oil-base mud cuttings	4, 5, 8
Crude oil	1
Used motor, gear, lubricating and hydraulic oil	1
Used solvents	1
Oily debris	2, 3
Diatomaceous earth	1, 2, 3, 4, 5, 8
Other filters media	1, 2, 3
Glycol, amine, and caustic wash	1, 7
Iron sponge	2, 3
Molecular sieve	2, 3, 4
Produced sand	2, 4, 8
Tight emulsions	1, 4
Used treatment chemicals	1, 7
Tank bottoms	4, 10
Paraffin	1, 2, 4
Asbestos insulation	3
Used batteries	1
PCB transformer oil	11
Non-PCB transformer oil	1
Empty oil and chemical drums	1, 3
NORM (naturally occurring radioactive material)	6, 12 (Not well defined)

*These are examples of disposal options and do not include all options for all wastes.

1. Reclaim and/or recycle
2. Onsite burial
3. Offsite landfill
4. Road applications
5. Onsite and offsite pits
6. Offsite commercial pit
7. Underground injection
8. Land farming
9. Surface discharge
10. Reclaim and/or recycle
11. EPA 40 CFR Part 761.6–Part 761.79
12. Storage

Generally, these disposal options are listed only as examples and may not comply with state waste disposal regulations.