A GUIDE TO ENVIRONMENTAL SITE ASSESSMENT FOR OKLAHOMA PETROLEUM EXPLORATION AND PRODUCTION PROPERTIES

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PREFACE

Preparation of this paper has been a challenging and rewarding exercise. I have seen that Oklahoma history is the history of a last frontier, and the economic boom of the industrial revolution. Oklahoma heritage is inseparable from the oil business. Oil from Oklahoma fields has helped the United States of America to be the industrial leader of the world.

The profession of geology has grown here, and geologists have played major roles in Oklahoma history. Geologists have lead many of the Oklahoma oil companies which are now global energy giants. It has been almost 100 years since the discovery of oil in Oklahoma Territory. Oklahoma has changed, as has the energy business, and the profession of geology. Our petroleum province has reached maturity and the people of Oklahoma are concerned about their environment. Concerns about environmental contamination in oilfield areas affect many different groups of Oklahomans, such as urban and rural property owners, water well users, farmers, and ranchers. Geologists are better prepared to answer questions about the environmental impact of Oklahoma's oil industry than any other profession.

This paper is both the result of academic and personal pursuits, as well as an example of how the profession of geology can build upon its experience. Geologists must be prepared to develop new products and services, as markets change. Domestic petroleum is a geologist's business. The needs of this industry are a natural place for geologists to solve new problems, and create new opportunities.

The basics of geologic education and training should not change fundamentally. It is the recognition of new areas of specialization, often from building upon specialized training such as petroleum geology and hydrogeology, that must be nurtured. I sincerely hope that this paper will serve the profession of geology in this way.

Readers should understand that the 1993 legislative session created the long awaited super agency for environmental regulation, the Oklahoma Department of Environmental Quality (ODEQ). The Oklahoma Corporation Commission (OCC) has not become part of ODEQ and remains the exclusive regulator of oilfield activities. ODEQ departments, consisting of former agencies discussed in this paper, continue to serve auxiliary roles with the Corporation Commission. The ODEQ is still being organized as of completion of this paper. Readers may use the old state agency names when requesting guidance regarding specific regulatory groups now within the ODEQ.

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Thank you to friends and associates in the petroleum and environmental industries for sharing your knowledge and concerns. My associates at the Oklahoma Corporation Commission helped to frame many questions and to clarify regulatory perspectives. Input from real people with real problems initiated and guided this study.

My dear wife, son, family, and friends abided occasional tunnel-vision on my part, and provided long term support which made it possible for me to complete this project. I extend sincere and gracious thanks to all of these wonderful people.

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CHAPTER I

INTRODUCTION

The state of Oklahoma occupies a region of geologic complexity and abundant mineral resources. More than 400,000 wells have been drilled for oil and natural gas in this state. The economic and social impact of petroleum exploitation has been broad, powerful, and progressive. The environmental impact of these activities, especially in light of current regulations, has not been sufficiently investigated. In Oklahoma, involvement with petroleum properties can occur in many ways. Examination of the rationale for real estate environmental site assessment reveals procedures that can be used to investigate environmental conditions at exploration and production (E&P) properties.

In order to evaluate a property's condition, environmental site assessments commonly are performed for commercial real estate transactions. The information needed, and the conditions to investigate must be determined by studying laws and regulations, industry practices, published research, and by the concerns of parties involved with these properties.

Many background records are available in the public domain. Environmental compliance information may be available from the files of operating companies and working interest partners. In cases of regulatory enforcement or litigation, large volumes of information may exist, but commonly only selected parts will be available to outside investigators. Site visits and environmental media sampling programs are needed in order to document site conditions.

Effective environmental site assessment requires a multidisciplinary approach. Geology and hydrology are critical elements. The profession of geology is well suited to performing environmental investigations to determine the impact of petroleum exploration and production activities. Exploitation activities may affect localized sites, but these sites should be recognized as parts of a regional producing province. Events documented at particular sites may help to develop investigatory procedures and risk management programs for larger producing trends. Oklahoma serves as the primary setting for this work. Some aspects may be peculiar to Oklahoma, but the general concepts and procedures are widely applicable.

This thesis is intended to assist persons interested in determining environmental conditions at oilfield sites. However, neither the author or other persons involved in the creation of this thesis make any representation, warranty, or guarantee, and hereby expressly disclaim any liability or responsibility for loss or damage resulting from its use. This thesis is not intended to serve as legal guidance. Regulations constantly change and should always be carefully researched for specific sites and circumstances.

CHAPTER II

UNDERSTANDING ENVIRONMENTAL ASSESSMENTS

Motivation For Environmental Investigations

The U. S. domestic petroleum industry experienced severe contraction in terms of product price, operating capital, and survival rates in the 1980's. This trend has continued into the 1990's, and significant improvements are not foreseen. During these lean times, managers have been forced to operate properties with a miserly eye on expenses and large staff reductions have occurred at most companies. In this business climate, why should managers be interested in performing environmental site assessments?

ASTM (American Society For Testing And Materials) defines environmental site assessment (ESA) as the process by which a person or entity seeks to determine if a particular parcel of real property (including improvements) is subject to recognized environmental conditions. ASTM defines environmental audit as the investigative process to determine if the operations of an existing facility are in compliance with applicable environmental laws and regulations. An environmental site assessment is both different from and less rigorous than an environmental audit

(ASTM E 1527, p. 5).

Environmental site assessments and audits should be regarded as management tools. Knowledge of the environmental conditions of properties a company is involved with is an important quality control issue. Knowledge about properties a company may wish to purchase also is crucial. In 1992, experts estimated there were U.S. domestic petroleum properties worth 6 billion dollars on the market. It is reasonable to assume that many properties involved in sales transactions warrant environmental site assessments.

Using environmental site assessments can provide some measure of control and protection for owners, buyers, lenders, and persons unintentionally involved with oilfield properties. This control can manifest in liability management, risk avoidance, business and public relations, and regulatory compliance. Environmental audits can be used to confirm and improve regulatory compliance. As regulation of all industries becomes more complex, petroleum operators need to apply formal programs to remain in compliance.

Social responsibility also is an important stimulus for environmental site assessment. The president of the Oklahoma Independent Petroleum Association (OIPA) noted at a recent Oklahoma City seminar, "a clean environment is the basis of all healthy economies."

Objectives of Environmental Assessment

Environmental assessment and auditing are business management tools that may be appropriate for petroleum properties. The terms, environmental audit and environmental assessment were initially applied to the same procedures. A good outline of real estate environmental auditing objectives is provided by Blackshare, Ede, and Turner (1991);

1. To better understand liabilities of acquiring property with environmental problems.
2. To avoid significant clean-up costs.
3. To provide the best advice to your company.
4. To minimize personal liabilities.
5. To avoid buying environmental problems.
6. To avoid foreclosing and acquiring environmental problems.
7. To establish baseline for protection of all (Buyer, Seller, Lender)
8. To understand and MEET "Due Diligence".

Liability Management

Liability for environmental contamination is one of the most pervasive fears of business managers today. Apprehension over becoming a Potentially Responsible Party (PRP) is common in real estate transactions, with ample justification. Real estate buyers, sellers, and lenders are interested in tools that will help them to avoid becoming involved with contaminated properties.

Environmental site assessment is an investigatory procedure developed to assist all involved parties in documenting the environmental condition of a property. An assessment report should document the environmental condition of a certain property, as it exists at a certain time.

The environmental professional will initially investigate a property through its paper history, then progress to a site investigation. An assessment should include a detailed examination of the property's prior owners and uses. The initial focus of an assessment is to determine if the potential for contamination exists. Documented information concerning the businesses formerly on the site will aid in judging what types of potential contamination should be investigated.

Some commercial real estate lenders avoid properties where high risk industries have operated, such as ore smelting or industrial waste disposal. Records from the

Superfund program (CERCLA) have been used to determine which industries have most often become PRP's. By identifying the standard industrial classification codes (SIC) of those industries and investigating for them, a lender could reject a property without going further into an audit (BNA, 1989, p. A-19).

Typically, the second phase of an environmental site assessment involves defining confirmed contamination. Sample collection followed by certified laboratory analyses of soil and groundwater, products, wastes, and unidentified materials are usually required. Geophysical investigation also may be employed, electrical resistivity and conductivity surveys can be used to locate buried metal, such as waste drums, and to delineate high chloride concentrations in groundwater.

The third phase of environmental investigation entails remediation of contamination that was delineated. This may be a relatively minor activity, such as excavation and landspreading of contaminated soil. Conversely, site contamination may be extensive and complex, such as Superfund cleanups, involving both soil and groundwater remediation. Costs for environmental cleanups vary widely, but can easily reach millions of dollars.

Case closure, which may be considered to be the fourth phase of the environmental site assessment process, is the final phase of a corrective action. Several successive periods of sampling in which contaminate levels are acceptable, are usually necessary prior to case closure. Currently, post-closure care is primarily an aspect of hazardous waste facility closure under the Resource Conservation and Recovery Act (RCRA). Expenses for post-closure care can be considerable, due to the length of time required for competent closure control.

Perspective of a Buyer

Reasons for performing environmental real estate audits vary with the perspective of the parties involved in any property transfer. A buyer desires to avoid acquiring contaminated property, which could result in an expensive clean-up, along with bewildering legal liability and loss of use of the property. If a buyer still desires the property, even though it is known to be contaminated, the buyer needs to establish extent and severity of contamination by the time of closing the purchase. The buyer may wish to use this information to negotiate a lower price, force disclaimers into the contract, or establish a shared responsibility for remedial action. The buyer may use an environmental site assessment to establish the property's condition at the time it changed ownership.

Perspective of a Seller

A seller needs for the property's environmental condition to be established at time of transfer, so that the seller will not be held liable for contamination that occurs after the sale. This type of report is called a baseline environmental assessment. The seller also may desire an environmental real estate audit to document a property's clean condition to improve its marketability, and perhaps to enhance its value.

Perspective of a Lender

Any party that serves as a lender for a property acquisition should require an environmental real estate audit. A lender's risk is created by holding a secured interest in the property (BNA, 1989). Should a borrower default, the lender may be forced to foreclose and thereby become an owner of the property. Without having performed a due diligence investigation, the lender becomes liable for environmental contamination just like any other owner.

The difference between an owner-operator and a lender, under the Comprehensive Environmental Response Cleanup and Liability Act (CERCLA), is that "owner" does not include,

> "... a person who, without participation in the management of a vessel or facility, holds indicia of ownership primarily to protect his security

interest in the vessel or facility." (42 USC 9601 (20)(A)).

In the case of foreclosure on a property, the lender usually becomes an owner, and therefore liable for cleanup costs if other responsible parties (RP's) cannot be assessed. In U.S. v. Maryland Bank & Trust Co. the court held that a lender who foreclosed on property can be liable for the costs of environmental cleanup (O'Brien, 1989, p. A7).

In the Maryland Bank case, after the bank had foreclosed, the U.S. Environmental Protection Agency (EPA) discovered hazardous waste on the property and performed remediation using funds from the CERCLA (Superfund) trust fund. The court ruled that because the bank held title at the time of the clean-up, it was clearly the owner and the responsible party for re-payment. The court noted that if a lender can escape liability, then CERCLA would become an environmental insurance policy for imprudent loans. In theory, banks could loan on contaminated properties that, after foreclosure and Superfund cleanup, could be sold at a profit. This ruling suggests that lenders should be prudent, and use environmental audits to protect themselves (O'Brien, 1989, BNA p. A-8) (U.S. v. Maryland Bank & Trust Co., 632 F. Supp. 573, 1 Toxics Law Reporter 730 (D.Md. 1986)).

Innocent Landowner Defense

Superfund Laws (CERCLA)(SARA)

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (42 U.S.C. 9607(a)) enacted on December 11, 1980, requires the federal government, through the EPA, to clean up sites contaminated with hazardous waste. CERCLA created a Hazard Response Trust Fund commonly referred to as the Superfund. The fund was created to pay for remediation of hazardous substance contamination at abandoned sites, or in emergency situations. A threat to human health and welfare must exist to justify CERCLA action. EPA has the authority to conduct investigations and response actions with Superfund trust money. Cost Recovery under CERCLA is authorized in Section 107. Section 106 allows treble costs under an enforcement order, if a PRP will not pay, and EPA goes ahead with remediation that is justified by Imminent and Substantial Endangerment (Focht, 1992).

Under CERCLA, property owners may be liable for cleanup costs, even if they had only minor involvement with contaminating the property. Under the doctrine of strict liability, the current owner may choose to pursue previous owners legally, for contamination. A superior strategy is to prevent a company from becoming involved with contaminated properties.

If an oilfield property has been involved with regulated hazardous substances, CERCLA is certainly relevant. Although many oilfield materials are currently exempt from the definition of hazardous waste, the regulatory methods used under CERCLA may be used as a model to create regulatory programs that operators will deal with in the future. Defenses against CERCLA actions may be an effective defense against liability under other programs.

In a recent Oklahoma Corporation Commission (OCC) case involving groundwater contamination at the Cement Oil Field, the hearing officer noted in his findings, "... the Commission is attempting to resolve the funding problem for cleanup through the imposition of what may be called, in a sense, "strict liability". He adds, "Under the Commission's policy, as in CERCLA, the Commission has not been really so interested in equitable apportionment but on "finding" a responsible party who can be held accountable for the cost of cleaning up the contamination... Thus, one can see that the rational behind the Commission's policy in holding active successor operators liable is simply the same rationale behind CERCLA." (Specht, 8-12-92, OCC PD 21825).

CERCLA was re-authorized in 1986 by the Superfund Amendments and Reauthorization Act (SARA). This law responded to concerns that property buyers and lenders could be held liable for Superfund cleanups even though they had no knowledge that the property was contaminated and had nothing to do with the operation of the property at the time of the contamination.

The Superfund Amendment and Reauthorization Act Of 1986 (SARA) was enacted on October 17. The SARA amendments address issues through five titles:

Title I: Provisions Relating Primarily to Response and Liability

Title II: Miscellaneous Provisions

Title III: Emergency Planning and Community Right-To-Know Act

Title IV: Radon Gas and Indoor Air Quality Research Act of 1986

Title V: Superfund Revenue Act of 1986

CERCLA Defenses

SARA Title I addressed defenses against liability under Superfund. A buyer or lender can utilize several defenses against liability for environmental remediation.

Third Party Defense. An owner may be able to prove that a third party placed hazardous substances on the property, employing the third party defense. An owner cannot utilize this defense if the third party has a "contractual relationship, existing directly or indirectly, with the defendant" (42 USC 9607(b)(3)). The term "contractual relationship" has been interpreted broadly, including deed transfers, so that this defense is narrow.

If a person assessed a property for environmental contamination prior to purchase, the report could support the third party defense. The owner will not be liable, if he can establish by a preponderance of the evidence, that the contamination was caused solely by an act or omission of a third party (O'Brien, 1989, p. A-10).

<u>Innocent Landowner Defense.</u> SARA provides that an innocent landowner will not be considered to be in a contractual relationship with the previous owner, if certain steps were taken prior to purchase. These steps are described in 42 USC 9601(35)(A) and are commonly referred to as the innocent landowner defense (O'Brien, 1989, BNA, p. A12).

> "(i)At the time the defendant acquired the facility the defendant did not know and had no reason to know that any hazardous substance which is the subject of the release or threatened release was disposed of on, in or at the facility.
>
> (B) To establish that the defendant had no reason to know, as provided in clause (i) of subparagraphs (A) of this paragraph, the defendant must have undertaken, at the time of acquisition, all appropriate inquiry into

the previous ownership and uses of the property consistent with good commercial or customary practice in an effort to minimize liability. For purposes of the preceding sentence the court shall take into account any specialized knowledge or experience on the part of the defendant, the relationship of the purchase price to the value of the property if uncontaminated, commonly known or reasonably ascertainable information about the property, the obviousness of the presence or likely presence of contamination to the property, and the ability to detect such contamination by appropriate inspection."

"Liken the search for the innocent landowner to Diogenes in the daylight with his lantern. If his contamination was discovered, then the innocent landowner defense did not apply, and if it was not discovered, then all appropriate inquiry was not made." (O'Brien, 1989, Toxics Law Reporter July 19, p. 184).

SARA Due Diligence Clause. The opportunity to utilize an innocent landowner defense poses the challenge of proving that appropriate inquiry was performed prior to purchase. What methods and procedures are reasonable? This issue was examined by the courts in U.S. v. Louis Serafini. The defendants purchased a property in 1969, which had been used as a landfill and waste disposal site. In 1983 the EPA removed more than 1,100 drums of hazardous waste from the site and filed suit against the owners to recover the cleanup costs. The defendants claimed to be innocent landowners and that they had not caused or known of the contamination.

The government presented evidence that at the time of purchase the land was visibly contaminated, with hundreds of drums on the surface. The defendants stated that they had not inspected the site prior to purchase, but relied upon maps and records to evaluate the land. Furthermore, the defendant claimed that it was not "customary and good commercial practice" to field inspect a property in 1969. They claimed not to have been aware of the wastes until the EPA began an investigation in 1980.

The government argued that a buyer cannot close his eyes to contamination, fail to inspect, then claim to be an innocent landowner. Government witnesses testified that in 1969, no reasonable purchaser of commercial property would have neglected to make a site inspection prior to purchase. The question became, whether the defendant's failure to inspect the property prior to purchase was inappropriate and therefore would render the innocent landowner defense useless. Attorney James P. O'Brien's analysis of this case notes that "Importantly, the court did apply the innocent landowner provision as it was contemplated by the statute. Even though the court held that it was conclusively established that the drums were visible at the time of acquisition, the court focused on whether the defendant's inaction was appropriate inquiry under the statute." (O'Brien, 1989, p. A-13).

The legislative history behind the innocent landowner defense is outlined in the conference report to SARA, noting that;

> The duty to inquire under this provision shall be judged as of the time of acquisition. Defendant shall be held to a higher standard as public awareness of the hazards associated with hazardous substance releases has grown, as reflected by this Act, the 1980 Act and other federal and State statutes.
>
> Moreover, good commercial or customary practice with respect to inquiry in an effort to minimize liability shall mean that a reasonable inquiry must have been made in all circumstances, in light of best business and land transfer principles (H.R. Conf. Rep. No.

962, 99th Cong. 2d Sess. 186-187 (1986))
(BNA, 1989, p. A-15).

O'Brien explained that "If it appears that appropriate inquiry was made prior to actually acquiring title, and no evidence was uncovered concerning the contamination, then EPA will not take enforcement action." (BNA, 1989, p. A-16). This conference report establishes the issue of changing standards, which are relevant for Oklahoma's petroleum industry. What was "good and customary" in the past may not be sufficient in the present. It also refers to the expectations of higher standards with more awareness.

Petroleum Industry Standards

The U.S. petroleum exploration and production (E&P) industry is a global leader in technical competence, professional staffing, financial and political strength. Considering the capabilities of the industry, it is reasonable to assume that petroleum companies would be held to a very high standard, if judged under CERCLA guidelines. In the case of a company buying or selling property at severe discount, failure to consider the possibility of environmental contamination will be difficult to defend.

Regulatory Compliance

Environmental investigations designed to assess regulatory compliance are called environmental audits. Environmental site assessments may be used also for compliance assessment. Federal, state, and local regulations should be considered when judging regulatory compliance. Environmental professionals may presume that state and local regulations will not contradict federal regulations. However, the local rules may be more stringent and may present complications for strict compliance.

Risk Management

Owners and operators who wish to manage environmental risks must have accurate information about their sites. Environmental assessments and audits provide that information. EPA has adopted procedures for environmental risk assessment and risk management that can be applied to petroleum properties.

Trends

The use of environmental site assessments is increasing as business people become more aware of environmental issues. Similarly, as more emphasis is placed upon the environmental assessment, more will be at stake for the assessor. On June 24, 1992, the Wall Street Journal reported that Fleet Financial Group would be the first major banking concern in the U. S. to require nearly all commercial real estate borrowers to get environmental insurance before they obtain a loan. Fleet's action is intended to lessen concerns about lender liability for environmental cleanups of properties under foreclosure.

The insurance will cover the borrower for a pre-existing condition that is not detected in the normal environmental assessments banks conduct before approving a loan. Obviously, banks are trying to protect themselves so that they never have to assume the liability for cleanup. The risk thus transfers to the insurance companies.

Insurance companies, now at risk, will not be satisfied with the bank's assurance that the property is clean. The introduction of additional potentially liable parties will result in additional rounds of environmental assessment as due diligence. Should contamination be discovered, potentially responsible parties will bring forth all manner of environmental information in existence. Anyone involved in this business should consider these possibilities, and strive to provide a scientifically accurate and defendable product.

CHAPTER III

REGULATORY OVERVIEW

History of U.S. Environmental Legislation

The United States of America is a country blessed with abundant natural resources. Growth of this nation from an idealistic republic to the world superpower has been based fundamentally upon exploitation of these resources. The United States had progressed beyond independence from England and the turmoil of a Confederate challenge to federal authority at the end of the 19th century. By the end of World War I in 1918, the industrial revolution was flourishing upon the ingenuity and innovation of people, empowered with the availability of abundant energy and raw materials. Oklahoma was a young state that played a major role in providing the nation with oil during these rapidly changing times.

In 1918 Oklahoma produced 103 million barrels of oil (Claxton, 1993). At this time the nation wanted to concentrate on business and put the First World War behind it. Beginning in 1921 with the election of Warren G. Harding, Republicans held the White House for 12 straight years. Calvin Coolidge was president during the Roaring

Twenties, and is well remembered for pronouncing that "the business of America is business." Federal business policy was laissez faire, letting industry fix the rules of competition without government regulation or control. Herbert Hoover's "Rugged Individualism" speech of 1928 referred to the "...peace-time choice between the American system of rugged individualism and a European philosophy of diametrically opposed doctrines - doctrines of paternalism and state socialism. ...Our American experiment in human welfare has yielded a degree of well-being unparalleled in all the world. It has come nearer to the abolition of poverty, to the abolition of fear of want than humanity has ever reached before."

One year and one week later, stock prices collapsed on Black Tuesday, October 29, 1929. The stock market crash was the most glaring symptom of the nation's economic ills. The United States descended into the worst economic depression in its history. More than 5,00 banks closed, millions of workers became unemployed, yet Hoover would not allow government to issue direct aid, as that would be socialism, something he could not abide (Davis, 1990). Hoover ran for president in 1932 on the general campaign that things were not as bad as they seemed and were surely improving rapidly.

In 1932, Franklin D. Roosevelt swept into presidential office carrying 42 of the 48 states and capturing 57 percent of the vote. Democrats also took over majorities of both houses of Congress. Roosevelt promised a "new deal" and began by calling a special session of congress known as the "One Hundred Days" (Davis, 1990). This famous session resulted in the creation of numerous new federal agencies, including the Tennessee Valley Authority, the Federal Deposit Insurance Corporation, Securities and Exchange Commission, and Works Progress Administration. These agencies' projects were wide-ranging and encroached upon activities that had been the privileged domain of private enterprise.

While many of the "new deal" measures were eventually ruled unconstitutional, a major evolution had begun. Roosevelt did more than simply create a series of agencies intended to help America deal with economic issues that individuals and the private economy had been unable or unwilling to resolve. His actions caused a fundamental shift in federal efforts to affect, control, and monitor American lives and businesses.

Laws dealing with the environment have a long history in the U.S. The first national effort to control water pollution was through the Rivers and Harbors Act of 1899. The act prohibited discharges that could interfere with transportation, into navigable waterways . Additional water pollution control acts were passed in 1948, 1956, and 1965. Federal laws dealing with environmental protection often grew out of concerns for commerce. The Federal Insecticide, Fungicide, and Rodenticide Act was enacted in 1910, amended in 1947, and reconceived in 1972 as FIFRA. The Federal Food, Drug and Cosmetic Act was created in 1938 and the original Clean Air Act dates from 1955.

As the 1960's came to an end, Congress believed that American society was sending them a message to protect the environment. Perhaps images of the devastation of the countryside in Vietnam, pictures of defoliant-spraying planes, and stories of horrible health effects experienced by U.S. soldiers, sparked deeper questions about how we treat our environment. Neil Armstrong's words, and the image of him stepping onto the lunar surface were experienced by most of the industrialized world on July 20, 1969.

Perhaps the unforgettable image of planet earth, shining bright and blue over the lunar horizon, reshaped peoples' concepts of their place in nature's scheme. Perhaps strong ideals of environmental protection were not created, but were rediscovered in awed recognition of individual fragility.

Regulation of activities that could affect human health and the environment literally exploded in 1970. These regulations are authorized by laws written by the nation's duly authorized federal and state congresses. While several "environmental" regulations date back to the 1930's and 1940's, most experts agree that profound changes in U. S.

environmental policy began in 1970 with passage of NEPA, the National Environmental Policy Act. NEPA caused several changes, such as the creation of the Council on Environmental Quality to advise the president on environmental matters and to make reports on environmental quality to Congress. But foremost, NEPA required all government agencies to consider the environmental effects of their projects and policies and to conduct Environmental Impact Statements of major actions. While the law did not require agencies to act in the least environmentally damaging way, NEPA represented a shift in federal environmental regulatory philosophy.

Regulatory structure presents two basic standards. The performance standard tells us what to do but the design standard tells us how to do it (Focht, 1991). The law is unable to define the design of proper actions for the unlimited number of possible situations. Regulations, which are created by an agency in order to enforce the intent of a law, may help clarify design standards. Even more helpful for understanding design standards are guidance documents. Guidance documents are more specific in describing technical methods, proper materials, and procedures which make up the design standard. However, the performance standard is foremost, and it must be followed to be in compliance with the law. Even regulations must meet the performance standard. Regulations are enforceable only if the regulations properly represent the performance intent of the law.

Regulation of Oklahoma Petroleum Exploration and Production

Oklahoma Corporation Commission

In Oklahoma, Corporation Commission is the primary agency regulating petroleum operations. Authority for the creation of the Corporation Commission is provided in the Oklahoma Constitution. The agency was created by the Legislature in 1907, the year of statehood, by Oklahoma Constitution Article IX, sections 15 through 35. The powers granted are wide-ranging and reflect the industrial concerns of the times: public utilities, cotton gins, and common carriers. The Commission has the power of a court of law, and has exclusive jurisdiction over matters under its regulation. Appeals of Commission orders go directly to the Oklahoma Supreme Court. No other state court has the power to rule on a case before the Corporation Commission.

Subsequent Oklahoma laws empowered the Corporation Commission to impose fines for rule violations and to issue contempt citations. Chapter Three of Title 17 established the Oil and Gas Conservation Division of the Commission, and confers exclusive authority over the conservation of oil and gas, drilling and operating of oil and gas wells, and construction and regulation of oil and gas pipelines

(Jackson, 1988). This section also provides rules and regulations for the plugging of abandoned oil and gas wells, a crucial environmental issue. The OCC Conservation Division was created to prevent waste, assure the greatest recovery of hydrocarbons, protect correlative rights, and prevent pollution.

It is important to understand that the OCC has exclusive jurisdiction over all phases of drilling and production. Other state agencies may have peripheral or auxiliary roles, but the OCC's primary jurisdiction has been enforced by Oklahoma Supreme Court Rulings, such as Pollution Control Board v. Oklahoma Corporation Commission, (660 p. 2d 1042 Oklahoma 1983). The OCC's jurisdiction is exclusive, beginning in 1917 with legislative decree of jurisdiction over all oil and gas matters. Subsequent statutes have followed the same premise, including Title 63 Oklahoma Statutes Section 2756 (now 63 O. S. section 1-2005), which granted the Commission exclusive jurisdiction over the handling and disposal of oilfield wastes (Jackson, 1988). Jackson summarizes that "Such statutes are cumulative in nature and repose all authority concerning petroleum production in the Corporation Commission."

Title 52 conveys broad powers to the OCC "to make and enforce such rules, regulations and orders" in the area of pollution in the petroleum industry " as are reasonable and necessary for the purpose of preventing the pollution of the surface and subsurface waters in the state, and to otherwise carry out the purposes of the Act." Throughout the history of the Oklahoma petroleum industry, the OCC has enacted rules to protect the environment. Many rule changes that resulted in progressively improved operating practices, were recommended by industry.

Statutes concerning environmental protection are found in Titles 17, 52, and 63 of the Oklahoma Statutes (Jackson, 1988, p. 2). OCC Rules are the embodiment of these laws and are available from the OCC, or commercially from Oil Law Records. The most significant rule developments in the area of environmental protection concern wellsite construction and maintenance, casing and cementing, underground injection, disposal of drilling and production wastes, plugging of wells, and land reclamation.

Regulations requiring casing to protect fresh water were established in OCC Order No. 17528 on January 24, 1945. These regulations are often cited as the earliest effort to protect the environment during petroleum development.
The Deleterious Substance Act of 1955 is codified in Title 52, Oklahoma Statutes. This law placed the power to make and enforce rules, regulations and orders governing any deleterious substances produced from, obtained or used in connection with the drilling, development, producing, refining and processing of oil and gas within the state as are reasonable and necessary to prevent the pollution of

surface or subsurface waters. Other sections of the act concern prevention of pollution and plugging of wells.

Title 52 also provides exclusive jurisdiction over toxic pollutants coming from petroleum operations. Title 52, O.S., Section 139 gives the Commission "jurisdiction, power and authority over salt water, mineral brines, waste oil and other deleterious substances whose source is from or obtained or used in connection with the drilling, development, producing, refining and processing of oil and gas within the State of Oklahoma or operations of oil and gas wells within this state."

Petroleum-producing states have progressed in the creation of comprehensive regulation, as the industry itself has progressed technologically. Laws that address potential for environmental contamination have become more effective and comprehensive over years of experience. Often, industry itself was responsible for promoting enactment of stricter laws and regulations.

Examples of environmental protection include surface casing requirements to protect ground water, restrictions on allowing wells to "blow" into the atmosphere and environment, regulation of unlined surface impoundments or "evaporation pits" for salt water and drilling fluid disposal, groundwater monitoring at commercial facilities, and technically advanced plugging procedures.

Regulations for field rules, drilling and spacing units, forced pooling, and production allowables are intended to provide for orderly development of petroleum resources. Prior to the 1960's, Field Rules might also include specific environmental protection mandates, such as casing depths and regulations on disposal pits. The concept of providing regulations for the development of energy resources came from legislative action designed to promote development while creating an element of fairness to various owners, prohibiting waste of natural and economic resources, maximizing tax revenue for the state and benefit of the state's people, and preventing pollution.

Critics of state regulation of the petroleum industry usually point out the conflict created by placing an agency in charge of promoting and regulating the same industry. Such is the case with Oklahoma's Corporation Commission. Yet in fact, petroleum operators are also regulated by other agencies. Some agencies are more efficient and effective than others, within the same or different states. Political conflicts and negotiated solutions occur with state regulators just as they do at the federal level. In the case of the petroleum industry and the Oklahoma Corporation Commission, a very strong bond of shared history exists with the state of Oklahoma.

As the chief regulator of the petroleum industry, the OCC administers the largest single source of records and information about petroleum properties. Discussion of specific records and their utilization in performing environmental audits is addressed in Chapter V. Relevant agencies and regulations should be considered for assessing compliance, and as potential sources of public information.

Other State and Local Authorities

Oklahoma Water Resources Board

The Oklahoma Water Resources Board (OWRB) regulates oil and gas operations in the areas of water allocation and water-quality standards relevant to clean-ups. The OWRB does not have any direct jurisdiction over wellsite related water pollution. Since oilfield sites are not permitted to have any discharges, there is no application of OWRB discharge permits. Any type of water treatment that utilizes surface discharge would require an OWRB discharge permit. The OWRB may present applications before the OCC for special cases. This was the situation that resulted in OCC Order No. 251978, which prohibits the construction of new commercial surface impoundments for the permanent storage and disposal of drilling wastes over the Rush Springs Aquifer (Jackson, 1988).

The OCC recognized that water-quality standards, usually set by OWRB, were needed in oilfield regulations. In 1988, the OCC incorporated the OWRB's water-quality standards by reference in OCC-OGR Rule 3-101.1. The

Legislature subsequently allowed the OWRB to promulgate statewide water-quality standards applicable to all state agencies.

With regard to environmental investigations, the OWRB regulates licensing of drillers for all types of geotechnical borings; monitor wells, peizometers, and borings. They set standards for these constructions which are set forth in OWRB rules, OAC 785:35, Chapter 35. Copies of these regulations are available from the OWRB. The OWRB also registers laboratories, which must meet stringent testing standards. A list of these labs is available from OWRB. This list is published annually, updated quarterly, and should be obtained and utilized by environmental professionals.

Oklahoma State Department of Health

The Oklahoma State Department Of Health (OSDH) regulates various solid and hazardous waste permitting, handling, and disposal matters. Petroleum industry regulation commonly concerns sewage disposal, such as septic tanks and portable toilets, and air emissions. The Department administers the Clean Air Act, that can affect petroleum operators by virtue of natural gas compressors and processing plants at production sites.

In regard to environmental investigations and remediations, OSDH regulates Underground Injection Control (UIC), except for Class II, which is regulated by the OCC. OSDH regulates solid waste and hazardous waste that may be present on a production site, although there are specific exemptions for many oilfield wastes. OSDH has partial authority over hazardous wastes under RCRA Subtitle C.

Oklahoma Conservation Commission

This agency has no direct control over petroleum operations but does possess a statutory mandate to participate in Corporation Commission actions regarding renewable resources. The Conservation Commission has management plans that may be affected by various soil farming practices. Therefore, they actively monitor drilling waste and produced water land disposal issues.

Municipal Regulation

There is no uniform set of local regulations for Oklahoma petroleum operations. The Oklahoma Supreme Court has upheld municipal regulations that related to reasonable control of public health, safety, moral or general welfare (Jackson, 1988). Cities may also regulate movement of heavy equipment and zoning, which can inhibit oil and gas development. Since 1935, 52 O.S. 1981 Section 137, municipalities have had a confirmed right to regulate or prohibit oil and gas wells within city limits.

Passage of the 1935 law can be chronologically correlated with events in the industry. The giant Oklahoma City Field was discovered in 1927. Production was established at the south end of the anticline and progressed northward. Geologists found the best prospects extended into the city limits but zoning prohibited drilling in many favorable areas, such as the State Capitol grounds and Lincoln Heights neighborhood.

An election was held to determine whether zoning for drilling would be allowed. The vote was close, but extension of drilling into the city was allowed. The field was a world-class discovery (Phillips, 1983). Old photographs clearly show that the environmental impact of oilfield development was significant. Eight years after the Oklahoma City Field discovery, the 1935 law confirmed that municipalities do have the power to regulate oilfield development.

Municipalities may request special field rules from the OCC for development in the area of city water supply wells. The cities of Enid and Alva currently have special rules for protection of fresh water aquifers (Atchinson, 1992). Similarly, cities may delineate wellhead protection areas (WHPA). Protective measures utilized by WHPA's may include land use controls and groundwater monitoring.

Federal Environmental Laws

Resource Conservation and Recovery Act (RCRA)

The Resource Conservation and Recovery Act (RCRA) is a set of amendments to the Solid Waste Disposal Act of 1976, which created the "cradle to grave" regulatory program for hazardous wastes. RCRA requires environmental remediation, termed corrective action, on the basis of a threat to human health or the environment. RCRA is made up of 10 subtitles. RCRA's 4 interrelated programs are (Focht 1992):

Subtitle C	Hazardous Waste Program
Subtitle D	Solid Waste Program
Subtitle I	Underground Storage Tank Program
Subtitle J	Medical Waste Program

RCRA was authorized in 1976 but regulations did not become effective until November 19, 1980. RCRA was amended by the Comprehensive Environmental Response, Compensation, and Liability Act in 1980, Hazardous and Solid Waste Amendments in 1984, and by Superfund Amendments and Reauthorization Act in 1986. This law, particularly Subtitles C and D, continues to be a very controversial issue. RCRA should be expected to continue evolutionary change.

Subtitles C and D are the primary RCRA concerns for persons involved with petroleum properties. RCRA regulations are under the jurisdiction of the Environmental Protection Agency. EPA regulations are in Title 40 of the Code of Federal Regulations (40 CFR). Title 40 CFR part 260 deals with hazardous waste management systems. Part 261 identifies and lists solid wastes that are subject to regulation as hazardous wastes under other regulatory parts. Part 261 also defines those wastes which are exempt from hazardous designation, such as petroleum exploration and production wastes. Part 262 provides standards applicable to generators of hazardous waste, and Part 265 is interim standards for treatment, storage, and disposal facilities. These regulations were promulgated under authority of the Resource Conservation and Recovery Act (RCRA) 42 U. S. Code 6901.

The regulatory concept of waste begins with the definition of solid waste. EPA uses a broad approach, defining solid waste as a solid, semi-solid, liquid, or confined gas (40 CFR 261). Another critical concept in the definition of waste is that a material be handled in a waste-like manner, discarded, abandoned, etc. Solid wastes are classified as hazardous either by listing in the regulations, or by exhibiting hazardous characteristics. Listed substances are designated "P" or "U" named (listed) wastes in 40 CFR part 261. Wastes with hazardous characteristics are F or K list wastes, or D wastes in part 261. Hazardous characteristics include toxicity, flammability, corrosivity, etc.

According to Focht (1991), an even broader concept of hazardous waste exists in the statutory definition, where it is defined in risk-based terms. The term hazardous waste applies to substances that, because of quantity, concentration, or physical, chemical, or infectious characteristics, may cause a significant increase in mortality or serious illness; or pose a substantial present or future hazard to human health or the environment when improperly managed (Federal Environmental Laws Title 42 section 6903 (5)).

Petroleum Waste Exemption. Petroleum exploration and production wastes are specifically addressed in U.S. Environmental Protection Agency regulations. In 1980, by the Solid Waste Disposal Act Amendments, Congress allowed petroleum drilling and production wastes to be exempt from hazardous waste classification under RCRA, pending a report from EPA determining whether such wastes were hazardous. The EPA report to Congress was, by law, to be completed by October 1982. EPA actually delivered the study to Congress in December 1987.

This exemption is extremely important in the area of waste management. Non-hazardous solid wastes are subject to only advisory regulations promulgated under RCRA Subtitle D (Jackson, 1988). In contrast, the hazardous waste management system under subtitle C is very demanding and utilizes "cradle to grave" liability standards.

In order to be classified as a hazardous waste, a substance must first meet the definition of a solid waste. Regulations in 40 CFR Part 261.4(b) identify solid wastes which are specifically exempt from designation as hazardous waste. Part 261.4(b)(5) lists:

> "Drilling fluids, produced waters, and other wastes associated with the exploitation, development, or production of crude oil, natural gas or geothermal energy".

EPA's report on the petroleum waste exemption was delivered to Congress in 1987. Following public comment, EPA issued a regulatory determination. The wastes in Appendix I are listed as exempt in EPA's Regulatory Determination submitted to Congress in June 1988 (Oil & Gas Journal, Dec 16, 1991, p.52).

The EPA report also included a list of non-exempt oilfield wastes, which includes painting wastes, used equipment oils, waste solvents, caustic or acid cleaners, radioactive tracer wastes, drums and anything else that is not on the exempt list (Jackson, 1988). Generally, non-exempt wastes constitute a small percentage of total wellsite wastes. Operators should work diligently to minimize hazardous waste generation, in order to remain exempt from RCRA subtitle C, or at least to qualify as a small quantity generator.

EPA determined that oilfield wastes are primarily large volume, low toxicity wastes that are adequately regulated in most states. State regulation is extensive and RCRA section 3009 preserves state jurisdiction. Typical oilfield wastes are not characteristically hazardous, and do not commonly present risk to human health and the environment. A 1985 national study of oilfield wastes by the American Petroleum Institute found that 99.9 percent of all oilfield wastes are drilling fluids and produced waters.

Persons involved with petroleum properties must be cautioned against believing that the RCRA exemption from hazardous waste designation somehow relieves them from critical management decisions regarding environmental issues. Timothy Dowd, executive director of the Interstate Oil and Gas Compact Commission commented, "Some persons have publicly asserted that, because there is no federal program for E&P wastes, these wastes are not currently regulated. This is simply untrue and ignores the efforts made by state governments that are vigorously regulating and upgrading regulations to ensure the protection of human health and the environment." (Oil and Gas Journal Sept. 16, 1991).

As environmental regulations change, petroleum operators must anticipate the ways they may be affected. The 1988 EPA report indicates that new Subtitle D regulations will be designed to strengthen regulation of oil and gas wellsites (Jackson, 1988). Risk based standards are rapidly gaining proponents in scientific and regulatory circles. Regulations that affect petroleum operators will likely be designed in a similar matter.

Hazardous waste issues can be petroleum exploration and production waste issues, and comparisons exist in other ways. It is very important to read the definition section for each law or regulation being referenced. The same word may have different meanings in different regulations. A common sense approach to the definition of regulatory terms is not wise. The interpretation of rules can change with judicial rulings. The U.S. Code Annotated may provide references to case law that deals with particular acts.

Petroleum professionals know that oil and gas wastes can present a hazard to human health, the environment, and the financial health of companies that mishandle their waste streams. Petroleum operators face both state and federal regulatory systems for solid and hazardous wastes. In addition to stringent state regulation by agencies such as the Oklahoma Corporation Commission and Texas Railroad Commission, Federal programs other than RCRA directly impact persons involved with oil properties. An examination of other significant laws and regulations follows.

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

The Superfund law (CERCLA) has far reaching powers in regard to assigning liability in cases of environmental contamination at abandoned sites. The principle of joint liability is applied by CERCLA. That is, any one potentially responsible party can be held liable for the entire cost of a clean-up. CERCLA, also known as Superfund, is primarily designed to find someone in the chain of ownership to pay for remediation of abandoned sites. In order to spread costs with other potentially responsible parties, companies are forced to pursue the other parties legally, at their own expense.

CERCLA cleanups are selected on the basis of the National Priorities List (NPL), that uses the Hazard Ranking System (HRS) scoring system for abandoned sites. CERCLA is designed to be applied retroactively to pollution problems. Conversely, RCRA cannot regulate sites that closed prior to its effective date of November 19, 1980.

Jackson (1988) notes that "As yet, the Corporation Commission has not been able to find an oilfield waste disposal site with a score sufficient to require listing on the NPL." "It is unlikely that the CERCLA cleanup remedies affect drilling and production wastes except in rare situations involving spills of reportable quantities hazardous substances under FWPCA Section 311."

Environmental investigators should be aware that of the ten Oklahoma sites on the NPL, three are abandoned oil refineries and one is an abandoned used motor oil refinery (EPA Progress At Superfund Sites in Oklahoma, February 1992). All these sites are in oilfield areas, near oil production. At least one of the Superfund sites has oil wells on it. Thorough site investigations should acknowledge any possible connection to a CERCLA site. Chapter One provides more detailed information about CERCLA, the SARA amendments, environmental assessment and the innocent landowner defense.

Safe Drinking Water Act

The Safe Drinking Water Act (SDWA), 42 United States Code 300 (f), designed to protect drinking water supplies, became effective in 1980. The Underground Injection Control (UIC) program was created under the SDWA. The purpose of the UIC program regulations (40 CFR 144-149) is to protect underground sources of drinking water (USDW's) from adverse effects from the injection of fluids. UIC directly affects petroleum production operations by regulating injection wells. State programs have generally protected water sources having maximum Total Dissolved Solids (TDS) of 3000 mg/l (API, Bulletin E3, 1993).

Underground injection wells are classified by their use and design. Class II wells inject fluids: (1) That are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection; (2) For enhanced recovery of oil or natural gas; and (3) For storage of hydrocarbons that are liquid at standard temperature and pressure. Class II wells include salt water disposal wells, which are common in Oklahoma and other oil producing areas. The Oklahoma State Department of Health administers the UIC program under a grant of primacy for the SDWA from the EPA.

Clean Water Act

The Federal Water Pollution Control Act of 1956, (amended in 1972 and renamed the Clean Water Act, remained the Clean Water Act in 1977 amendments, and was amended by the Water Quality Act of 1987) has a stated goal of making all surface waters fishable and swimmable. The act is codified in Title 33 U.S.C.A., Navigation and Navigable Waters. The act regulates pollutant discharges into surface waters. It also regulates discharges into Publicly Owned Treatment Works (POTW's) by establishing Pretreatment Standards.

The regulations apply to "...owners or operators of non-transportation related onshore and offshore facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, or consuming oil and oil products which by their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the U.S. or adjoining shorelines" (40 CFR 112.1(b)). Exemptions are provided, including 40 CFR 112.1(d)(14) "...facilities, which, due to their location, could not reasonably be expected to discharge oil into or upon the navigable waters of the U. S., or adjoining shorelines."

FWPCA Section 307 (b). Indirect discharges, also called non-point sources, are regulated by this section of the CWA. Discharges to POTW's require pre-treatment permits, which are issued by municipalities and define what substances may be discharged into the sewer system. The authority to issue these permits is provided by the NPDES permit explained in Section 402, which the POTW must maintain. Each city establishes the law and may prosecute to enforce city law. If a petroleum operator is discharging water to a POTW, a pretreatment permit should be obtained from the city.

The topic of NPDES permits for non-point source discharges, such as storm water runoff from petroleum sites, is addressed in Section 307 (b). Storm water discharge permits are required for most commercial sites. Refer to the discussion of Section 307 (b) that follows.

FWPCA Section 311. The Federal Water Pollution Control Act was one of the first environmental laws to affect the petroleum industry widely, by empowering the Environmental Protection Agency with regulation of onshore oil and hazardous substance spills and spill prevention planning. Under the Clean Water Act amendments, these plans are known as Spill Prevention and Control and Countermeasure Plans (SPCC Plans) and are required by CWA Section 311. Exceptions are listed, although most production sites should be considered to be regulated. Reporting of accidental petroleum spills may be required under the CWA.

CWA section 311 set Reportable Quantities (RQ's) for 300 Hazardous Substances. CERCLA took this list and added to it, with more than 700 total RQ's set by 1992. Oil spills remain under the Clean Water Act, though other substance spills are now regulated under CERCLA. Section 311 provides authority to clean-up spills and assess liability. For oil spills to surface waters, this section is structured as a mini-superfund. Actually, the CERCLA regulations were modeled after CWA Section 311 (Focht, 1991).

Section 311 has been court interpreted to define a harmful quantity for an oil spill to be a sheen on water, a stain on the ground, or deposition of a sludge on bottom of any body of water (Spurlin, OIPA, 1992). Petroleum product sites must have an SPCC plan if they store 1320 gallons above ground, 660 gallons in more than one tank, 42,000 gallons below ground, or have a history of spills.

An SPCC Plan should include information about where spilled oil would flow, the quantity that could be released, how the spill would be contained, and the schedule upon which tanks will be visually examined. All inspection records must be signed and maintained for a period of three years. Personnel training should specifically discuss the SPCC Plan and make sure it is understood and kept updated. The SPCC Plan must be amended if a spill larger than 1000 gallons goes into or is upon navigable waters, if two spills of harmful quantities occur within a one year period, when an addition to the facility, or a change in equipment has been made at the facility.

A Contingency Plan should be pre-arranged with Local Emergency Planning Committees, such as police and fire departments, hospitals and emergency response teams. A list of company personnel that can coordinate emergencies should be included, as should a list of emergency equipment, and an evacuation plan. It is very important to maintain copies of the plan in offices, on sites, and in company support vehicles (Turner, 1991). The regulations are in 40CFR 112.

Porter Engineering listed SPCC Evaluation Factors in their 1992 OIPA program.

1) Prior spill history

2) Location (proximity to navigable waters)

3) Potential size of discharge

4) Soil type and terrain

5) Frequency and amount of rainfall

6) Surrounding land use

7) Population

Evaluation of these parameters involves several issues. Spill history is least important because the active date, 1974, post-dates much of Oklahoma's most significant production activity. "Navigable waters" can be interpreted so broadly as to include practically any body of water or stream. Daily production rates, storage capacity, and purchase scheduling should be considered. Soil and geologic conditions will influence infiltration versus runoff conditions. In catastrophic situations, such as tank failure during rainfall, consider adequate containment area, and changing transport directions.

Porter's explanation (OIPA, 1992) lists important procedures for the SPCC Plan:

1) On-Site Activities

  a) Facility inspection and report

  b) Photo/video documentation

  c) Data/sample gathering

2) Off-Site Activities

  a) Gather and review commercial data

    i) Topographic maps

ii) County soil maps

iii) Groundwater maps

iv) Climatological data

b) Review owner/operator data

i) Current production volumes

ii) Prior spill history, document causes

iii) Title III chemicals, including crude oil

c) Findings and recommendations

i) Risk assignment on evaluation factors

ii) Recommendation

iii) SPCC Plan preparation, certification and distribution

A well prepared SPCC plan may provide environmental professionals with valuable information about specific sites. The operator of record should have the SPCC plan, but may not make it available to environmental site assessors.

FWPCA Section 402. Section 402 established standards for discharges, and thereby created the National Pollutant Discharge Elimination System (NPDES). If a facility creates a "discreet conveyance" discharge or is a point source discharge to surface waters, a NPDES permit is required. The requirement for a NPDES permit is not triggered by certain volumes. The permit will define when to monitor and will set discharge limits. Permits will vary with the type of facility and may set volume limits. The NPDES system interfaces with RCRA for hazardous waste and also with CERCLA.

OWRB regulates water-quality programs in Oklahoma, but does not have primacy under the CWA. NPDES permits must be obtained from EPA Region VI in Dallas, Texas. Generally speaking, if a potential exists for contaminants to leave the facility, a storm water discharge permit is needed. EPA published information on NPDES general permits for storm water discharges associated with industrial activity in the Federal Register, Vol. 57, No. 175/ September 9, 1992.

Existing or new discharges composed entirely of storm water from oil and gas operations do not need a permit, unless the site has a history of spills involving hazardous material Reportable Quantities (RQ's) or the facility contributes to a violation of a water quality standard(40 CFR 122.26(c)(1)(iii)). Oil and gas operations not required to submit an application in accordance with 40 CFR 122.26(c)(1)(iii), but that have a discharge of oil or a hazardous substance for which notification is required must submit an NOI within 14 calendar days of the first knowledge of such release. Involved parties should obtain and utilize the FR documents and the EPA Guidance Manual, EPA-505/8-91-002, April, 1991.

Petroleum exploration and production activities usually involve four of the six activities identified as major potential sources of pollutants in storm water discharges associated with industrial activity (FR 1992): 1) loading or unloading of dry bulk materials or liquids; (2) outdoor storage of raw materials or products; (3) outdoor process activities; and (4) waste disposal practices.

The General Permit required Notice Of Intent (NOI) to be filed with EPA by October 1, 1992. Operators of facilities that begin industrial activities after October 1, 1992 are required to submit an NOI at least 2 days prior to the commencement of the new industrial activity. No sampling or testing is required for oil and gas properties, under the General Permit. Currently, no application fee is charged.

Overall, the regulatory intent is for most sites to be permitted. Operators should file the NOI form with EPA, afterwhich 180 days are allowed to prepare the Pollution Prevention Plan (PPP). An additional 180 days is allowed for implementation. The Pollution Prevention Plan does not have to be filed with EPA, but should include the SPCC and be filed internally. The PPP should include site specific information, the facility audit, receiving bodies of water, 3rd party litigation. PPP's were to be prepared and implemented by April 1, 1993. The plan should explain contaminant transport pathways. It is an integral part of the general permit.

EPA and the American Petroleum Institute have guidance on Pollution Prevention Plans. EPA currently provides seminars and other assistance in permit preparation. The Oklahoma Independent Petroleum Association publishes a SARA Title III guide that also addresses some of these issues.

Pollution Prevention Plans (PPP). For each facility, the PPP should identify;

potential pollution sources

storm water management

pollution minimization measures

incorporation of SPCC plan and response

The PPP should also document;

personnel training

regular (annual) site inspection procedures

maintenance to reduce storm water contaminants

FWPCA Section 404. Section 404 of the CWA is the Wetlands program. This program operates between the EPA and Corps of Engineers. The Corp issues dredging and filling permits and EPA develops discharge quality standards that are incorporated into the permit.

Clean Air Act

The Clean Air Act governs air emissions. Air emissions from industrial sites, such as natural gas compressors or environmental remediation equipment, may require permitting from OSDH. Federal regulations are set forth in 40 CFR 50 - 99.

TSCA

PCB contamination is regulated under the Toxic Substances Control Act, as is asbestos, both of which may be found at petroleum installations.

National Environmental Policy Act (NEPA)

The National Environmental Protection Act (NEPA 1970) mandates that federal agencies must assess the environmental impact of any proposed projects or regulations. NEPA requires an Environmental Impact Statement before drilling on some public lands. NEPA is a procedural, rather than substantive, statute. While agencies must consider environmental impact, they are not required to choose an alternative based upon those considerations. However, in this age of environmental concern, political posturing by numerous special interest groups should be expected to carry significant influence in government considerations.

Industry Focus on Environmental Regulation

As with other industries, oil and gas operators have become increasingly affected by environmental regulatory issues. In order to manage their liabilities, independent operators have begun to seek guidance. In 1992, the Oklahoma Independent Petroleum Association initiated an educational seminar series for their members titled Environmental Awareness. These programs were presented "in order to provide a thorough overview of current environmental regulations, and how those regulations impact the independent energy producer, his employees, his customers and his vendors" (OIPA, 1992). The 1992 seminars specifically addressed regulatory issues that the OIPA and its members felt were most relevant at the time.

1) Spill Prevention Control and Countermeasure Plans
2) Pipeline Safety Regulations
3) Stormwater Permits
4) Naturally Occurring Radioactive Materials
5) OSHA Hazardous Communication Standard
6) SARA Title III
7) Clean Air Act

CHAPTER IV

THE PETROLEUM EXPLORATION AND PRODUCTION INDUSTRY

Oklahoma Historical / Social Perspective

Petroleum is an important product of the geologic history of Oklahoma. Early Oklahoma Indians and settlers used oil from seeps for medicinal purposes. The first petroleum records are of shallow oil deposits in northeastern Oklahoma. A well drilled for salt, produced oil near the town of Salina in Mayes County in 1859 (Johnson K., 1992). The first recorded annual state production was 30 barrels of oil in 1891. The first commercial oil well is recorded to have been drilled near Bartlesville in Washington County, Indian Territory in 1897. Oklahoma Territory became a state in 1907 and was at that time the nation's greatest oil producer. Since then, petroleum has been produced in 74 of the 77 counties of Oklahoma.

Nationally, Oklahoma ranks third in natural gas reserves and fifth in crude oil reserves (Mid-Continent Oil and Gas Association, 1992). The state's deepest production is natural gas from more than 4 miles deep (25,670 feet) in the Anadarko Basin in Beckham County. The state's deepest oil producing well is located in Comanche County. The Kerr

McGee, Seymour well produces crude oil from deeper than 15,500 feet in the Anadarko Basin, near the structurally complex Wichita Mountain front. The state's shallowest oil wells are 320 feet deep and are located in Craig County on the Ozark Uplift.

Facilities required to produce petroleum resources include wells, tanks, processing equipment, and pits. Commercial salt water disposal wells are common in producing areas. Commercial disposal facilities are active in 11 Oklahoma counties, with inactive commercial disposal facilities located in 27 counties (OCC, 1992).

The geology of Oklahoma also provides aquifers that are widespread. While about 80 percent of municipal and industrial water is supplied by surface water sources, ground water provides 80 percent of irrigations water and is the only source of drinking water in many rural locations. Oklahoma aquifers consist of alluvium and terrace deposits as well as bedrock units of sandstone, limestone, chert, and evaporite sequences (Johnson K., 1991). The Oklahoma Water Resources Board (OWRB) estimates 22 percent of Oklahoma's daily water use, excluding irrigation, is from ground water. If total irrigation volumes are considered, ground water accounts for 60% of daily use.

Impact from the exploitation of petroleum resources upon ground water resources is an important concern in Oklahoma. Claims of legal liability have arisen from contamination of ground water supplies in Oklahoma oilfields. Responsibility for the damage, and expenses for litigation, replacement water supplies, and remediation, are risks for responsible persons involved with oilfield properties.

Economic Impact

The economic benefit of exploiting Oklahoma's petroleum resources has been enormous. Oklahoma's greatest annual production volume was more than 277 million barrels of oil in 1927, prior to statewide prorationing by the OCC. Production during 1990 was 112 million barrels of oil and 2.26 trillion cubic feet of natural gas, with a combined value of approximately $6 billion. By the end of 1990, more than 400,000 wells had been drilled for petroleum in Oklahoma. Wells currently producing oil and natural gas still exceed 124,000 (Johnson K., 1991). From 1891 through 1990, cumulative production was about 13.5 billion barrels of oil and 67 trillion cubic feet of natural gas. Crude oil reached an all time high value of $37.60 per barrel in 1983, but fell dramatically to $11.15 per barrel during 1986. By 1991, statewide crude oil production volumes had declined to the lowest levels since 1920.

The petroleum industry spins off vast revenue in state taxes. In 1921, receipts from the Gross Production Tax made up 71 percent of the state's budget (Mid-Continent Oil and

Gas Association, 1992). In Oklahoma the gross production tax applied at the wellhead is 7 percent. It was increased from 5 percent in 1971. This tax makes the state a risk-free partner in every oil and gas well drilled in the state. In 1991, the Gross Production Tax generated over $411 million in state revenues. The Petroleum Excise Tax and Gas Conservation Excise Tax added another $7 million (Oklahoma Tax Commission, 1991).

Petroleum money also is paid to mineral owners in royalty payments. Jobs related to the petroleum industry are numerous and include all skill and wage classes. Unfortunately, many of these jobs have been lost since 1982. More than 450,000 jobs in the U.S. petroleum industry have been eliminated in the last 10 years, according to the Wall Street Journal.

Oklahoma's energy resources have been significant in building this state and this nation. Oklahoma oilfields played a major role in supplying the United States with oil during WW I, from world-class discoveries at fields such as Glenn Pool and Cushing. Oklahoma oil flowed prolifically from Oklahoma fields during WW II (Mid-Continent Oil and Gas Association, 1992). Oklahoma oil and natural gas are vital commodities, integral components of every conceivable form of enterprise, product, and service.

Sequence Of Petroleum Resource Development

Petroleum properties and producing areas can be recognized to move through stages of development. Generally this involves exploration, discovery, production, development, enhanced recovery, and abandonment. The process is similar to a product life-cycle. Petroleum provinces develop in stages also. Recognizing the stage of a property, and its province, can aid in assessing environmental risks. This may be a complex issue when old fields experience new zone discoveries, and overlay new development cycles upon older ones. Examination of statistical data can illustrate aspects of province development, and province maturity (Figure I).

Significant Exploration & Production Technology Issues

Knowledge of Process

In order to assess any property, a basic knowledge of industry practices is required. Consideration of processes, practices, and technologies provides what is commonly referred to as knowledge of process (Turner, 1991).

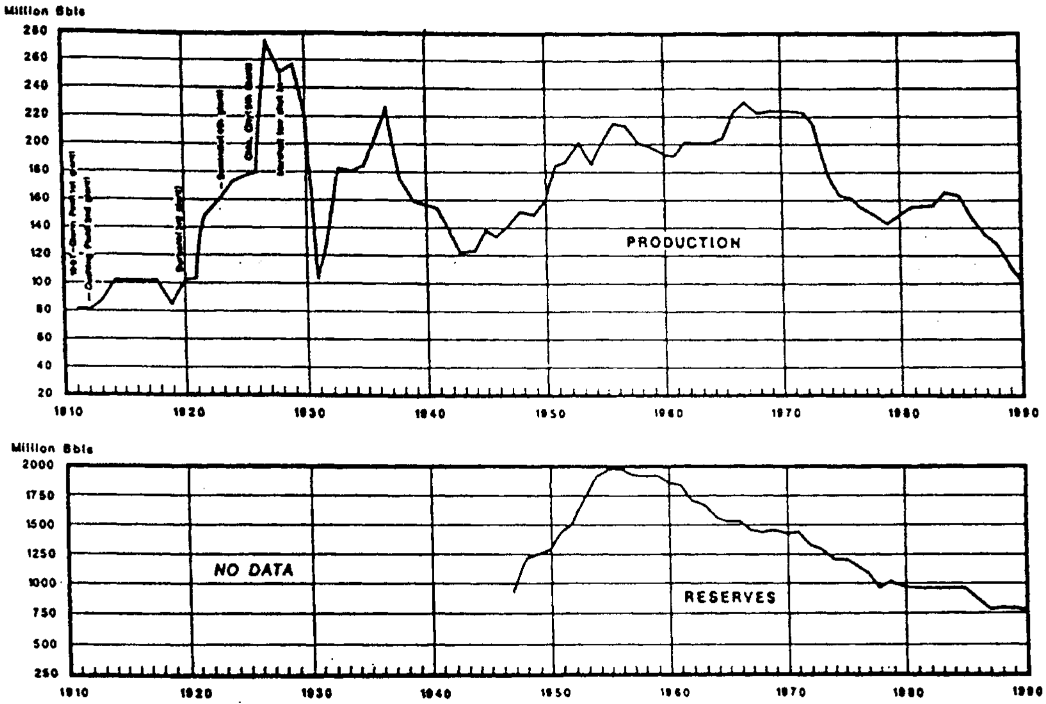
Drilling

The birth of the oil industry in the United States is credited to Col. Edwin Drake in 1859. Colonel Drake and Billy Smith devised a steam powered modified spring pole

FIGURE I

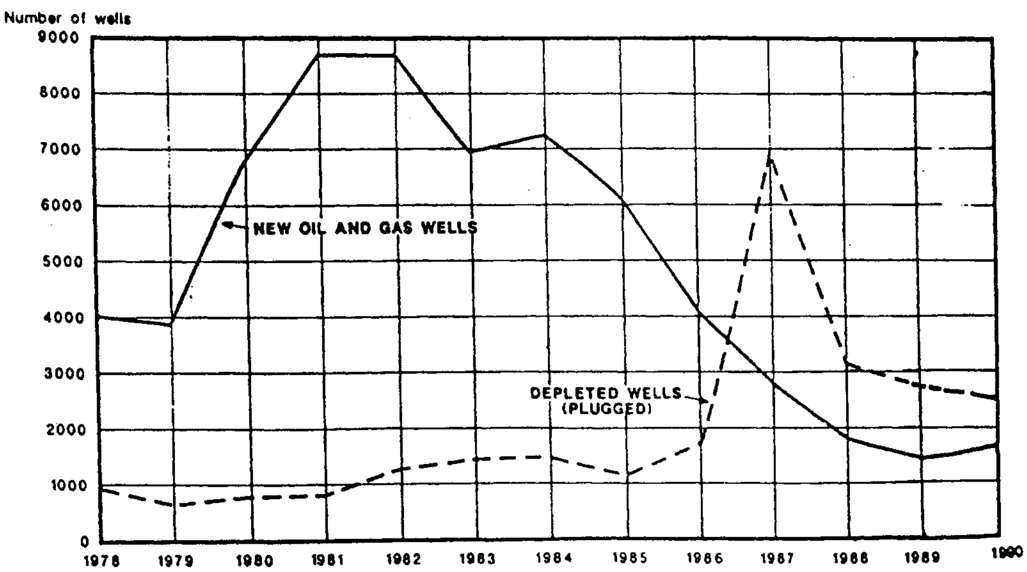
ENERGY STATISTICS

OKLAHOMA OIL AND CONDENSATE PRODUCTION AND RESERVES



Early giant discoveries and limited demand caused a glut of oil. Prices were reduced to as little as $0.25 per barrel by 1928; at this time the governor declared Marshal Law and shut in all oil production. Following the shut-in proration production increased, but development did not until prices stabilized in 1943. Following 1943, both reserves and production increased until the peak of reserves was reached in 1956 and the peak of production in 1970. After 1970, both reserves and production began the general decline to present. High prices due to OPEC's manipulation produced an upturn in the early 1980's.

NEW AND DEPLETED WELLS IN OKLAHOMA



As a result of oil and gas prices reaching a low in 1985/86, wells of low productivity or high costs were rapidly plugged in 1987. Although experts believe Oklahoma oil reserves and production will continue to decline, the same is not true of gas due to anticipated deep and relatively undeveloped areas. Price increase and demand could expedite drilling.

Shale Shaker/January/February/1992

Illustration from Lamar, 1992.

dropping a steel bit to the bottom of the hole. Occasionally a bailer is used to remove cuttings, mud, and bits of rock from the hole. The method requires shallow target depths and competent rock that will not cave or be damaged. In Oil Creek, Pennsylvania on August 27, 1859 after drilling through 30 feet of rock, Drake struck oil at a depth of 69 feet (Berger and Anderson,1981).

Cable tool rigs were used to drill shallow oilfields found in the early 1900's. Cable tool drilling is an open hole procedure. Unlike later rotary drilling, no drilling fluid, called mud, is used. If cable tool drilled holes proved to be dry, meaning not petroleum productive, many were abandoned without consideration for plugging. Operators plugged some holes with tree trunks and posts.

Rotary Drilling. Rotary drilling utilizes a hollow drill stem turning a drill bit. Drilling fluid is circulated down through the drill stem and bit, to lubricate and cool the bit, as well as to wash cuttings up out of the hole, and stabilize the wall of the hole. The basics of rotary drilling were well understood in the mid 1800's. One of the earliest patents issued for rotary drilling systems was granted to Robert Beard in 1844 (Berger and Anderson, 1981, p. 48).

By 1901, primitive rigs had been used to rotary drill more than 100 wells in Texas. Credit for uniting the technology, allowing successful application of rotary drilling, is given to a mining engineer named Anthony Lucas. His steam powered rotary rig reached a depth of 1,020 feet on January 10, 1901. The well blew out, sending a 200 foot stream of oil into the air for nine days that resulted in an 800,000 barrel lake of oil. The well discovered Spindletop Field at Beaumont, Texas and ushered in the dominance of rotary drilling in the new age of petroleum.

Steam powered rotary rigs came into more common use after the Spindletop discovery in 1901. Many of the early Oklahoma fields did not require the rotary since cable tools worked well. The first rotary drilled wells in Oklahoma were drilled near Tonkawa, at the Three Sands Field, in 1922 (Brittenham, T., personal communication 1991). Although cable tool drilling was still the predominant method in shallow plays throughout the 1920's, rotary rigs were able to drill deeper and open many of the major fields of the late 1920's and 1930's, such as the giant Oklahoma City Field. Modern petroleum drilling relies almost exclusively on rotary tools.

Drilling Fluids

Rotary drilling uses drilling fluid or mud, allowing drilling through soft, even unconsolidated formations. The mud's weight acts to stabilize and support the wall of the hole. As mud liquids infiltrate into porous and underpressured zones, mudcake develops on the rock face, thus providing a low permeability seal. If the well proves to be a dry hole, and is abandoned without setting a string of casing, this mudcake and the mud filling the hole can inhibit movement of fluid through the hole from one zone to others. Drilling mud in an abandoned rotary drilled hole lowers environmental contamination risk, compared to an unplugged cable tool drilled hole.

Drilling muds are primarily water based mixtures of clays and inert weighting materials with special additives mixed in low concentrations (API EGD, 1989, p. 31). Drilling mud additives allow the mixture to be customized for special situations. An example is the addition of crude oil or diesel fuel to reduce friction in directional holes or to reduce swelling in water sensitive formations. For some geologic formations, the mud is mixed as an oil based, rather than water based fluid. Mud components serve various functions. Clays increase viscosity, barium sulfate (barite) acts a weighting agent to increase mud density, and lime and caustic soda increase alkalinity. Other additives may include polymers, starches, lignitic material, biocides and various chemicals. Drilling cuttings become part of the mud and must be managed as waste. Drilling fluids and cuttings are exempt wastes under RCRA subtitle C (40 CFR 261.4(b)(5).

Mud additives can be environmental contaminants.

Barite is the most common mud additive, due to its high density and low cost. Barite is commonly mined along with other minerals. In the early Oklahoma oilfields, barite for drilling mud often came from the sprawling Miami to Pitcher zinc mining trend in northeastern Oklahoma. Barite seams from this area contained fairly high concentrations of zinc and lead. These minerals can become concentrated in old drilling mud pits, creating hazardous constituent concerns (Spurlin, P., personal communication 1992).

Earthen Pits

Throughout the history of the petroleum exploration and production industry, earthen pits were commonly used. Pits were used for holding fresh water, collecting cuttings, and for formation fluids. Rotary drilling mud commonly was mixed in unlined pits, which also served to collect formation water and cement returns from drilling and testing. Trash and burn pits were commonly abandoned, both properly and improperly, on locations.

Crude oil was stored in surface pits at many early Oklahoma fields because production volumes from the field vastly exceeded available tank storage and transportation capacity. In order to competitively produce a lease, operators produced as quickly as possible and stored the oil wherever they could. Pipelines and production facility infrastructure gradually eliminated the need for product pits.

Pro-ration rules, which were designed to force equitable field development along with more reasonable environmental regulation, stopped surface storage of oil after 1955. Oklahoma was the first state to enact pro-rationing, in 1914 at Cushing, the state's second giant field.

Formation water produced along with crude oil was often run down to a creek or pumped to earthen pits until new regulation in 1955. Salt water disposal pits, called evaporation pits, can contain high chloride concentrations and act as ground water contamination sources for many years (Pettyjohn, 1971). The same can be true of commercial mud disposal pits and drilling pits in some areas.

Environmental problems from earthen pits include soil contamination, leakage, and concentration of contaminants. Liners that are now in use substantially reduce the risk of pit leakage. However, prior to 1987 few surface pits were lined. Pits are commonly constructed of the soils present at the drilling site. The composition of the soil would effects the competency of the pit. Lined pits have been required for drilling in hydrologically sensitive areas since 1987. Drilling rigs with closed mud systems, utilizing tanks rather than pits, are preferred by some operators and are becoming more common for all drilling sites.

Areas considered sensitive to ground water contamination are defined by the Oklahoma State Department of Health / Oklahoma Corporation Commission map of Hydrologically Sensitive Areas (Oklahoma Geological Survey, Johnson, 1983). Sensitive areas consist of recharge areas and alluvial deposits. Arid areas with deep water tables, and low permeability shales at the surface that act as confining layers for aquifers, are at less risk.

The type of soil used to construct a pit may affect its competence. However, even seemingly low permeability soils can transport contaminants, sometimes at surprising velocities. High velocity is attributed to vadose zone macropores, which can rapidly transport contaminants to the water table (Pettyjohn, 1982).

Earthen pits have the potential to leak whatever fluids they may contain. Drilling mud may serve beneficially by caking the pits floor and walls, as it does the hole wall during drilling.

Modern Noncommercial Pits

A noncommercial pit is an earthen pit located either on-site or off-site, that is used for the handling, storage, or disposal of drilling fluids and/or other deleterious substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste (OAC 165:10-7-16(a)).

Noncommercial pits are regulated by the OCC and are currently differentiated on the basis of; reserve/circulation pit, completion/fracture/workover pits, and other types of pits. Regulatory distinctions also are made on the basis of water or oil-based drilling fluids, chloride content, and whether the pit is located in a hydrologically sensitive area (OAC 165:10-7-16). Some pits are required to be lined, and some are not.

Drilling operations commonly require use of earthen pits of several types. When using rotary drilling, operators used surface pits to mix the drilling mud and to catch drilling cuttings. If the well "kicked" or began flowing formation water, these fluids also would be collected in the mud pit. Completion operations also flow cement returns and treating fluids to the pits.

The OCC offers several alternatives for disposal of reserve pit wastes in OAC 165-10-7-16(e). These closure options include:

(A) Evaporation/dewatering and backfilling.

(B) Chemical solidification of pit contents.

(C) Annular injection (requires permit).

(D) Land application (requires permit).

(E) Disposal in permitted commercial pit.

(F) Disposal at permitted commercial soil farming facility.

(G) Disposal at permitted recycling/reuse facility.

Waiver of closure requirements may be allowed if rules are followed and analyses of the fluids show that the following ranges or concentrations are not exceeded (OAC 165:10-7-16(e)(9)):

(A) pH - 6.0 - 9.5 s.u.

(B) Chlorides - 3500 mg/l

(C) Total Dissolved Solids (TDS) 7000 mg/l

(D) Chromium (Total) 10 mg/l

(E) Arsenic 20 mg/l

Drilling Wastes

Drilling operations generate wastes such as rigwash and waste water, drilling muds, formation cuttings, cement returns, and equipment maintenance materials such as lubricants and filters. RCRA subtitle C exemption applies to drilling fluids and cuttings, but does not apply to many other drilling wastes. Non-exempt wastes include trash, drums and containers, unused or residual sacks of chemicals, pipe dope, paint, lubricants, and fuel oils (API EGD, 1989).

Support equipment for drilling operations may include fuel tanks, mud pumps, centrifuges, shale shakers, desilters, electric generators, pipe racks, and personnel quarters. Wastes generated may include waste oil, fuel spillage, sewage, solid waste, mud additive spillage, formation cuttings, oil filters, and other garbage.

Modern operations increasingly utilize closed mud systems using tanks rather than pits. Even where pits are used, drilling fluid haul away to commercial disposal is often used rather than closing the pit on-site.

Completions and Workovers

After drilling, wells must be completed for production or injection, or plugged. Typically the drilling rig will be used if a casing string is run in the hole. Refer to Figure II. Workover rigs are often used for other completion activities, because they operate at lower costs than drilling rigs. Workover rigs can run tubing in the hole for completion and production set ups, can trip logging tools, and perforate in target zones. Downhole equipment can be installed and the well may be acidized, fractured, or otherwise stimulated.

Existing production and injection wells may require periodic maintenance utilizing workover rigs. Workover operations can involve installing tubing and packers, acidizing or fracturing stimulation, replacing tubing or pumping equipment, recompletion to new zones, or plugging and abandonment of wells (API, EGD 1989).

Wastes generated from workover operations may be none, as in electric logging jobs, or volumes consistent with drilling operations if a well is deepened, recompleted, or stimulated. Spent fluids may include crude oil, produced water, mud weighting agents, surfactants, acids,

FIGURE II

CASING STRING DESIGN

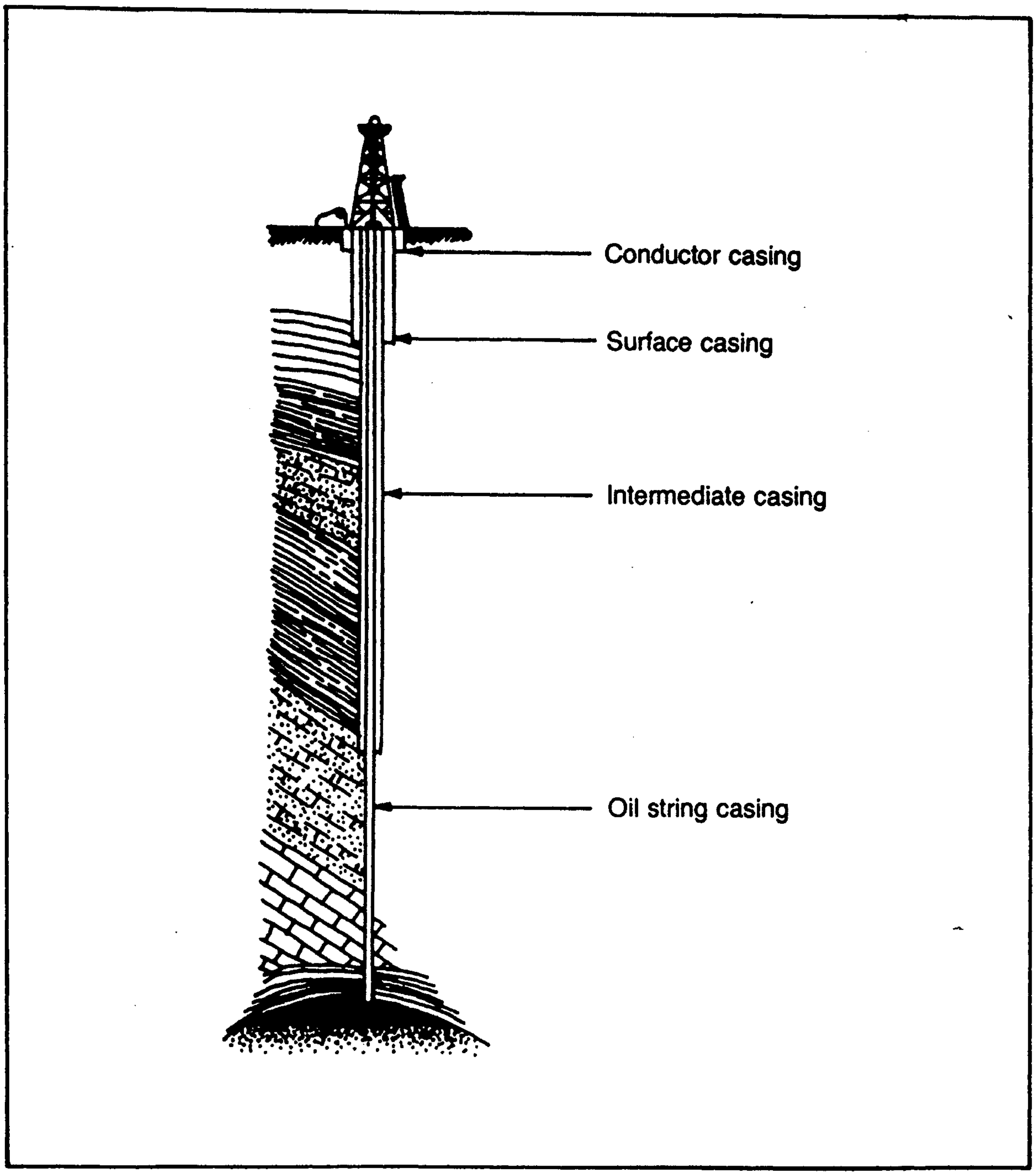


Illustration from Berger and Anderson, 1981.

inhibitors, gels, solvents, cement, and other materials. Spent workover and completion fluids often are produced through flowlines to production facilities or trucked to other facilities. Workover rig wastes may also include hydraulic fluids, used oils, fuels, and filters (API, EGD 1989).

Cementing and Plugging

Cementing is the process of bonding a casing string to the formations that are the walls of the hole. The purpose is to isolate hydrocarbon productive zones and zones to be protected, such as fresh water zones. Cementing wastes will be generated by drilling and completion activities.

Cementing casing in wells began in 1903. The use of wiper-like plugs began in 1910 and cement plug placement in wellbores became possible by the mid 1930's (API,Bul E3, 1993). Halliburton invented the modern cementing techniques in 1934 (T. Brittenham, personal communication 1993). Halliburton's cement plug technique allowed efficient placement of cement volume in the annular spaces between the casing and the hole. It resulted in more secure isolation of zones at the surface and conductor casing strings which protect shallow zones and aquifers.

Cementing for abandonment, known as plugging, also became more effective by using modern techniques to emplace cement plugs through the drill pipe, as a well was being abandoned. The OCC regulations in Subchapter 11 provide detailed information on the methods to be used in plugging wells (OAC 165:10-11). Refer to Figure III.

An improperly plugged hole provides a vertical pathway across geologic zones which would otherwise be isolated. Surface runoff flowing down an open hole can contaminate aquifers, where dirty operating practices, or other forms of surface contamination exist. If hydrostatic head is altered by pumping or injection, in zones connected by an open hole, fluids will flow through the lowest pressure pathway and attempt to equalize pressure.

Wells plugged prior to the 1930's generally were unregulated concerning proper plugging procedures (API, Bul E3, p.5). In 1939 Oklahoma enacted plugging regulations. After 1940, modern cementing technology was commonly in use (API, 1993). Based upon OCC records, 62% of all Oklahoma wells were drilled after 1940. This number is slightly lower than the 65% since the mid 1940's which Brooks (1988) calculated nationally. This comparison attests to Oklahoma's leadership in petroleum exploration and production, and resulting maturity of the province.

API Bulletin E3 (1993), <u>Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations</u>, provides excellent reference on well plugging. Natural phenomena may also work to plug wellbores and inhibit environmental contamination. The following natural safeguards may occur in a given well (API, 1993):

1) Wellbore impediments such as mud in the hole, filter cake, and sloughing shales or collapsed formations.

2) Subsurface formation effects such as pressure equalization due to porosity, permeability, density, and viscosity variation. Formation fluids flowing upward may be captured by deeper formations, thereby protecting fresh water zones.

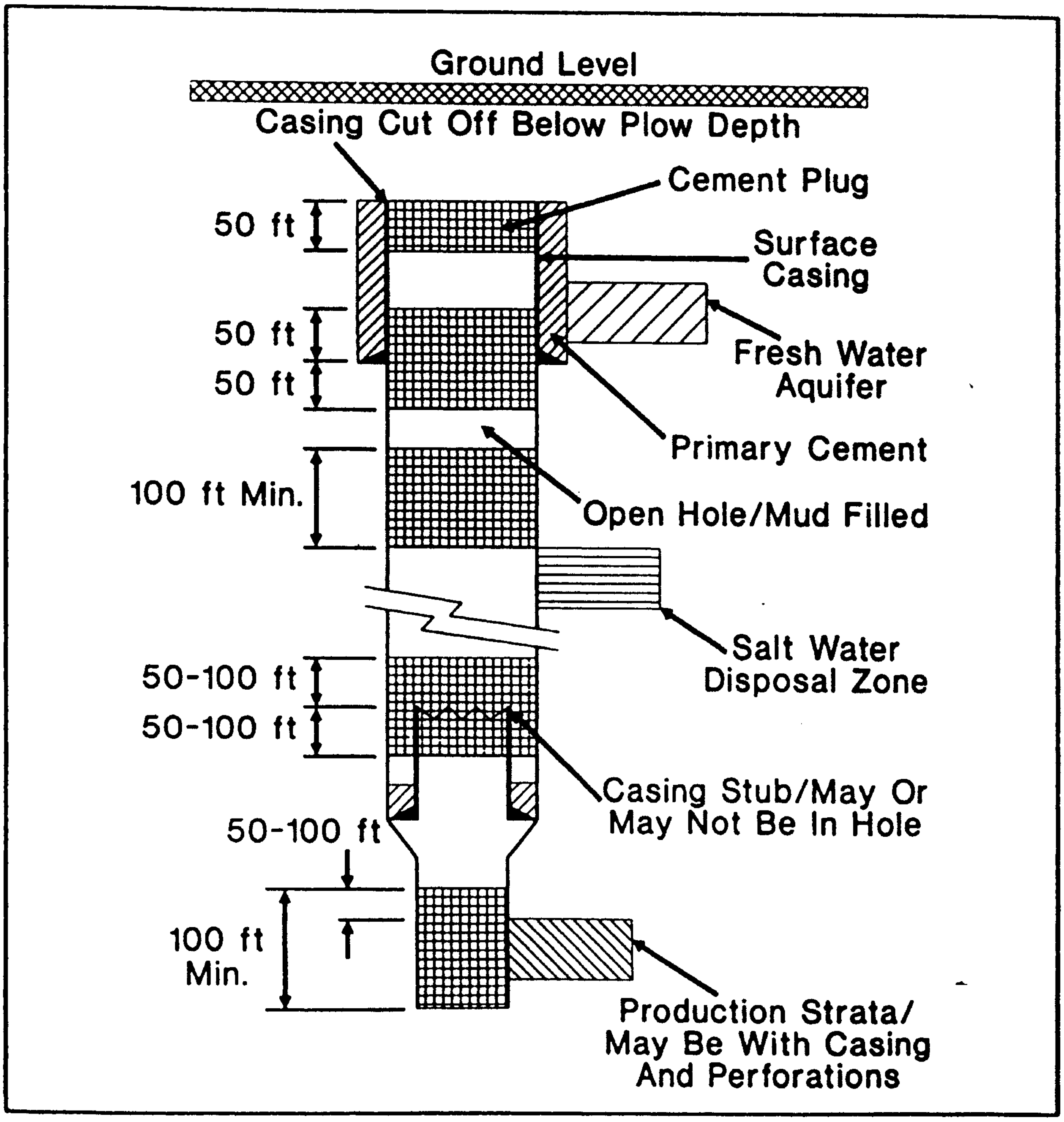
3) Formation pressure equalization between injection rates and volumes and withdrawal rates and volumes due to production. In enhanced recovery injection, production withdrawals may balance injection, thereby eliminating the possibility of injection pressures pushing fluids up other holes.

Field Production Facilities

Field facilities serve the function of collecting oil and/or natural gas from wells to prepare it for sale. Equipment to separate fluids produced by the well into product and waste are common. Separators may be free water knockouts, two phase or three phase separators, heater treaters, or gas flotation vessels. Open, closed, or pressurized stock tanks may be used to store oil and produced water.

FIGURE III

PROPER WELL PLUGGING



SCHEMATIC OF PROPERLY PLUGGED WELL

Illustration from API, 1993.

Wastes produced at oil wells include paraffin, oil and produced water contaminated soils, and lubricating oils. Paraffin and scale can build up in flow lines and be generated as a waste during cleaning operations. Line heaters and methanol injection used to prevent ice in lines, may generate empty methanol containers and spent thermal exchange fluids such as glycol, oil, or salt water mixtures. Liquid residue such as heavy hydrocarbons, solids, sands, and emulsions collect in tanks, vessels, and separators and are known as "tank bottoms" (API, EGD, 1989). Most equipment has clean out ports to remove this type of waste. Over time, tank bottoms may become concentrated in the soil around these ports.

Water treatment may be used, especially at waste water injection sites. Filters are commonly used, and may become waste. Electric or gas engines usually power injection pumps, where other fuel and lubricating oil wastes may be generated. In operations where steam is generated, boiler water may be considered a waste product.

Natural gas wells produce less waste than the typical oil well, but may have associated gas plants. Gas plants provide centralized dehydration, compression and sweetening facilities necessary to extract natural gas liquids and market natural gas. Natural gas producing wells may require a compressor to boost gas into the sales line, for vapor recovery, or to allow flow into central processing facilities. Compressors may be electric or combustion powered, and may produce engine cooling water and lubrication oils and filters as wastes.

Natural gas often contains water vapor which must be removed prior to sale. Typically, natural gas is dehydrated by contact with liquid or solid desiccants. Common liquid desiccants include ethylene, diethylene, or triethylene glycol which may be recovered and reused. Solid desiccants include alumina, silica-gel, silica-alumina beads. Dehydration wastes include glycol based fluids, glycol filters, condensed water, and solid desiccants (API, EGD 1989).

Gas plants remove unmarketable gases, such as hydrogen sulfide and carbon dioxide, from the natural gas stream. Amine sweetening can produce spent amine, used filter media, and acid gas which must be flared, incinerated or sent to a sulfur recovery facility (API, EGD 1989). Caustic treating also removes hydrogen sulfide, and generates caustic solution as a waste. Gas plant utility and compression equipment systems may also include fuel facilities, electric generators, steam equipment, pumps, and sump systems to operate the plant. These engines, compressors, and systems generate used lubricating oils, cooling water, hydraulic oils, solvents, sorbents, filters, and oily debris. Fluids usually are collected from sumps into a central clarifier where waters are separated for disposal.

Natural gas liquids are extracted by compression and/or cooling processes, absorption processes, or cryogenic processes. Wastes generated include lubrication oils, spent or degraded absorption oil, waste water, cooling tower water, and boiler blowdown water.

Salt Water Disposal

One of the most pervasive elements of oilfield environmental contamination is brine water produced along with hydrocarbons. Practically all oil fields generate large volumes of waste water from the producing zones. These fluids are usually very high in total dissolved solids (TDS), especially sodium chloride salt. Produced water TDS may range from several hundred ppm to over 150,000 ppm . By contrast, seawater is typically about 35,000 ppm TDS. These fluids may also contain trace amounts of additives, such as coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors (API,EGD 1989). The EPA maximum concentration limit for chloride in drinking water is 250 ppm. Oilfield produced water is exempt from hazardous waste designation by 40 CFR part 261.4(b)(5).

Salt Water Disposal Pits

Up until 1955, the preferred method of handling waste brines and chloride contaminated drilling fluids was to impound these fluids in unlined "evaporation pits", on or near the production site. Often, hundreds of barrels per day were pumped into these pits. Regardless of soil type, most of these fluids seeped into the underlying strata, creating potential for groundwater contamination. Industry's focus was on producing the wells and disposing of waste water as quickly and cheaply as possible. Operators have been known to use dynamite to loosen the floors of pits from which water evaporated too slowly.

A full pit creates hydraulic head by increased gradient. Through time, the processes of evaporation and infiltration cause chloride to concentrate in the pit. Pettyjohn, et al found that chloride concentrations in pit soil could be much higher than that of the formation water. Even after the pit is covered and abandoned, this concentrated salt can be leached from soil and degrade groundwater and surface water quality. Pettyjohn (1971) found that chloride plumes moved through the unsaturated zone into unconfined aquifers at several sites in Ohio.

Groundwater monitoring at the Ohio sites showed that chloride concentration changed cyclically. When groundwater chloride concentrations are correlated to precipitation records, a strong relationship is observable. A hydrologic study using monitoring wells at various sampling depths, showed that the groundwater chloride plumes grade laterally, as well as vertically, in terms of concentration. Refer to Figure IV.

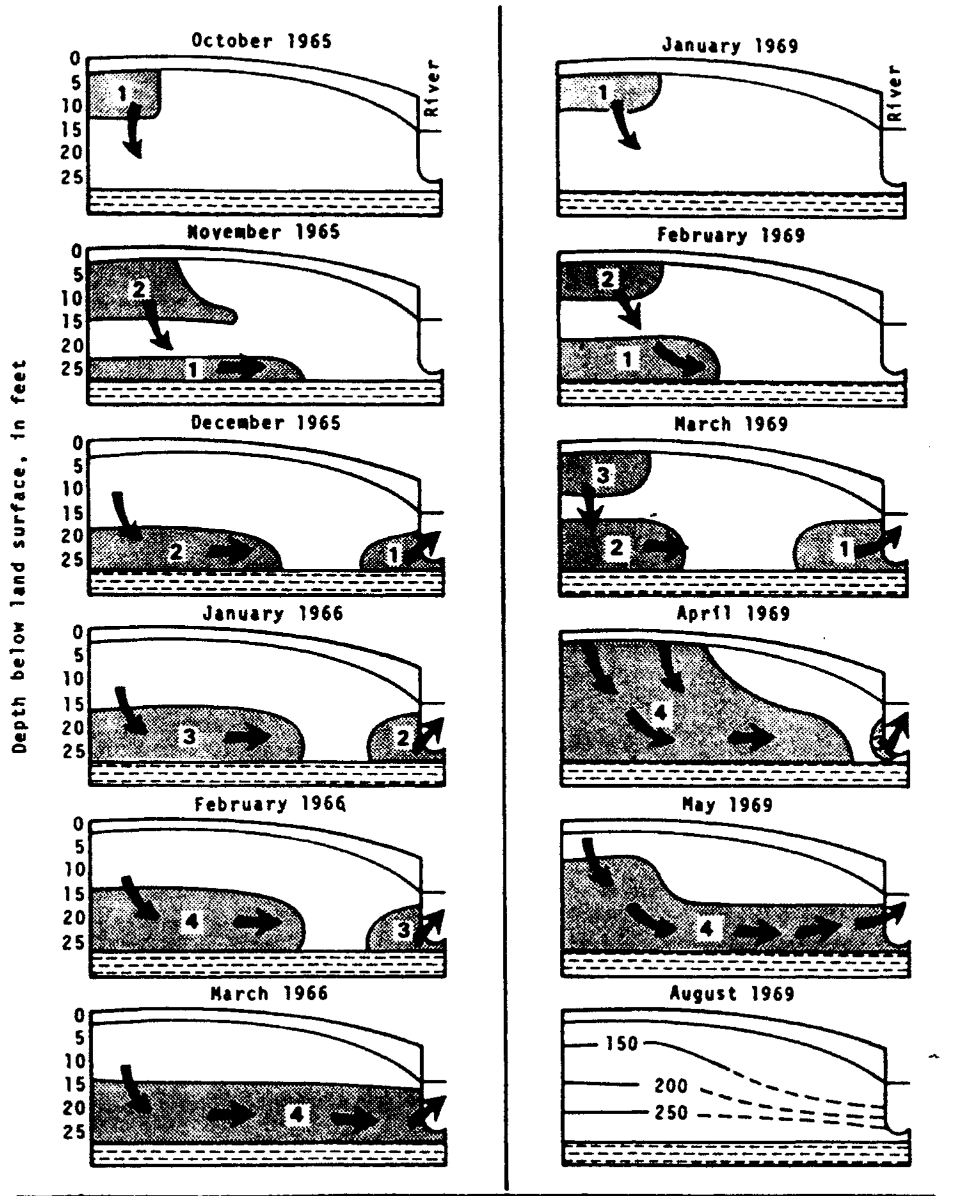
An investigator must try to determine whether a salt water disposal pit existed on or near the property under audit. If the area was not drilled until after 1955, the odds that water disposal pits were used is much lower. Similarly if the area is a dry gas field with no produced waters, or formation water is fresh, this environmental risk is avoided.

Example: Cement Field Saltwater Disposal Pits.

References to brine disposal pits may be found in geologic literature. Tanaka and Davis discuss the water quality of wells in their report on the Ground Water of the Rush Springs Sandstone (Circular 61 OGS, p. 51). Water from a well in sec. 3-5N-9W "contains 1,160 ppm chloride and probably was contaminated by surface seepage as a result of ponding of oil-field brine nearby". The referenced area is in the sprawling Cement Field which was discovered in 1917. Environmental professionals should search for this type of reference. Properties in this immediate area involve a high degree of environmental risk. This risk emanates from both regulatory and civil liabilities which may exist under the concept of strict liability, or may be transferred to new owners. At the least, a new owner could face bewildering and expensive legal complications and long term

FIGURE IV

CHLORIDE CONTAMINATION FROM PITS



Schematic diagram showing the cyclic movement of masses of contaminated water through the aquifer during selected months in 1965, 1966 and 1969. Stippled areas for 1965-66 represent concentrations in excess of 20,000 mg/l and for 1969 represent concentrations greater than 500 mg/l.

Illustration from Pettyjohn, 1971.

status as a potentially responsible party.

In the case of the Cement Field, an Oklahoma Corporation Commission administrative law judge concluded from evidence presented in extensive hearings brought by the Commission that, "It is clear that both the Rush Springs aquifer and Marlow aquifer have been contaminated by chlorides from oil and gas operations within the area..." Although Mobil Corp. sold its interests in the field to Citation Oil and Gas in 1989, the administrative law judge recommended that the commission order Mobil and Union Texas to pay for an investigation to determine the extent of contamination plume and whether remediation is feasible (The Daily Oklahoman, August 14, 1992, p. 17).

Underground Injection

Oilfield injection wells are categorized as Class II and are regulated by the Underground Injection Control Program (UIC), which was created by the Safe Drinking Water Act of 1974 (refer to Chapter III). Class II wells are used to dispose of fluids associated with the production of oil and natural gas, to inject fluids for enhanced oil recovery, or for the storage of liquid hydrocarbons. Class II injection wells have been used in the oilfield since the 1930's. In Oklahoma, there are more than 22,000 Class II injection wells including 5,841 disposal wells handling about 5,930,000 barrels of produced water per day, nearly all of the water produced daily in Oklahoma (OIPA State Review, 1992, p. 5).

All Class II wells are regulated by the Oklahoma Corporation Commission. A Commission Order has always been required for injection permission, but prior to the effective date of the Oklahoma UIC program, December 1, 1981, Orders may have authorized injection over an entire field area. Current regulations are set forth in OAC 165:10 subpart 5 (OAC 165:10-5). Mechanical integrity testing is mandatory prior to commencement of operation at any injection well authorized by a Commission Order after December 1, 1981. This information is submitted on Form 1075. Other mechanical integrity requirements set forth in OAC 165:10-5-6 require annual reports and 5 year mechanical integrity testing.

Commission UIC regulations now require special hearings for wells proposed within one-half mile of municipal water wells, and do not allow injection within designated wellhead protection areas. Because the UIC regulatory program was instituted in Oklahoma on December 1, 1981, wells in existence at that time became "existing wells", authorized by rule. Area Of Review investigations have not been performed for most of these wells. Authorization for existing injection wells requires the operator to submit an inventory Form 1070 for enhanced recovery wells and Form 1071 for disposal wells (OAC 165:10-5-3).

Naturally Occurring Radioactive Materials

Naturally occurring radioactive materials (NORM) occur in many geologic horizons. They are ubiquitous in the environment. Regulation of these materials is a very current issue. Only Louisiana has a regulatory structure now. Texas is reported to be working on regulations and Oklahoma is likely to follow the lead of these other petroleum producing states.

This topic will undoubtedly receive much more attention in the future. The occurrence of NORM varies widely, even among wells that produce from the same formation, in the same field. Environmental professionals should be aware that NORM tends to collect wherever fluid velocities allow scale formation in production equipment. Particular areas to check are around heater treaters, at pipe elbows and in tank sludges. Also inspect pipe elbows, clean-out ports, load lines, and anywhere tank bottoms may have been dumped. The American Petroleum Institute has prepared a videotape presentation regarding NORM issues (order number 811-10850) and other publications are becoming available.

Modern Waste Management Processes

General guidance for petroleum exploration and production waste management revolves around four basic concepts (API, 1991, p. 4 and API, 1989, p. 47):

1) Source Reduction - Reduce or eliminate waste generation, usually by process modification. Source reduction may include treatment and recycling within a process.

2) "Recycling - Recycling refers to the reuse of a waste as an effective substitute for a commercial product, or as an ingredient or feedstock in a process. It also refers to the reclamation of useful constituent fractions within a waste material or removal of contaminants from a waste to allow it to be reused."

3) "Treatment - Treatment refers to methods designed to change the physical, chemical, or biological character of hazardous waste in order to render the waste non-hazardous or less hazardous." Strive to employ techniques to reduce the volume or the relative toxicity of waste that has been unavoidably generated.

4) Proper Disposal - "Disposal refers to discharge, deposit, injection, dumping, spilling, leaking, or placing of any waste into or on land or water."

In order to make good management decisions and to document them:

1) Check applicable federal, state, and local

regulations and provisions of the lease.

2) Consider proper notification of landowners and regulators.

3) Evaluate longterm fate and transport issues for wastes.

4) Maintain excellent records of waste disposal activities. Include records that document the type, quantity, method, location, date, and other information about the waste, even when it goes to commercial facilities.

Waste Management Plans

Waste management plans must be designed based upon specific site conditions. Soil types and hydrologic settings influence the options available for waste management and for remedial actions. The 1989 API Environmental Guidance Document provides a good guideline for area waste management plans.

API Guidelines For Developing Waste Management Plans:

Evaluation of Existing Environmental Conditions

General Site Overview

Hydrologic Evaluation

Area Rainfall or Net Precipitation Conditions

Soil Conditions and Loading Considerations

Drainage Areas

Environmentally Sensitive Conditions

Air Quality

Selection of Waste Management Options

Waste Minimization

Other Waste Management Practice

Specific Regulatory Requirements

Tracking Offsite Disposal Shipments

Storage Restrictions

Hazardous Waste Management

Options For Managing Drilling And Production Wastes

Only general approaches are presented here. In the OCC regulations, OAC 165 Chapter 10, Oil and Gas Conservation, subchapter 7, Pollution Abatement, provides good specific guidance for waste disposal options. A reference chart is presented at 165:10-7-24.

Drilling fluid wastes should be managed to protect soil, ground and surface water. API recommends the following basic steps to manage theses wastes:

1) Minimize generation and toxicity. Reduce excess fluids entering the pit. Avoid toxic additives such as hexavalent chrome and formaldehyde.

2) Do not mix EPA non-exempt wastes with reserve pit fluids. Do not mix potentially hazardous drilling waste with reserve pit fluids. Collect these wastes and use appropriate hazardous material management procedures.

3) Design the drill site to control stormwater runoff and rigwash, and to emplace these fluids in the reserve pit. A sump pump setup may be needed. Design the site so that lubricating oil, fuel, or product spills will not enter the reserve pit.

4) Reuse and recycle drilling fluids as possible. This step is a cost saver for oil based muds or high density brines.

EPA does not consider drilling rig and machinery maintenance wastes to be exempt from hazardous designation. Used oils, paint, product containers, should be managed as potentially hazardous materials. Pumps, equipment, fuel tanks, chemical storage areas should be diked to prevent spills, drainage, and leaks from being transported across a site, including during precipitation events. Oil recyclers and fuels burners offer disposal for waste oil products. Sewage and solid waste should be handled according to local requirements. Empty drums should be returned to the supplier if possible, or treated appropriately based upon their prior use. Use materials in partially empty containers. If any water wells, monitor wells, or borings are used in the operation, they must be properly plugged, refer to OWRB regulations.

Hazardous waste exempt materials include well completion, treatment, and stimulation fluids; inert materials originating from downhole mechanical repair activities such as produced sand, formation and pipe scale, and cement cuttings; and pieces of downhole equipment such as sealing elements and pumping equipment (API, EGD 1989 p.39). These materials should usually be collected in lined pits or tanks, not in unlined earthen pits. Reuse and recycle when possible, transport through flowlines and production facilities for processing if possible, and clean the entire well site at the end of workover or completion activities. Class II injection wells usually provide the most economical disposal method for appropriate fluids. Use landfarming when possible and solid waste disposal for other wastes.

Tank and vessel bottoms may be recombined with crude oil sales or may be taken to off-site reclaimers. The exploration and production hazardous waste exemption may not apply to off-site reclaimers, so be cautious about where and how waste streams are treated, stored, and disposed. Road or land spreading may be a feasible option, if regulations are followed. OCC regulations for land application of various wastes are set forth in OAC 165:10-7.

Studies by Freeman and Deuel, 1986; EPA ,1987 have shown that waste / soil mixtures with soluble salt levels below 3000 ppm TDS (approximately 4 mmhos/cm conductivity), exchangeable sodium percentage less than 15, and a sodium adsorption ratio less than 12 cause no harm to soil vegetation, surface water, or groundwater. Oil and grease concentrations up to one percent by weight were found to biodegrade effectively (API,EGD 1989 p.49). Soil farming methods are effective for most petroleum contaminates.

Soils contaminated with hydrocarbons are hazardous exempt wastes. API believes that produced water contaminated soils are also exempt (API, EGD 1989 p.42). Materials contaminated with hazardous substances or other hazardous wastes must be managed according to RCRA subtitle C hazardous waste regulations.

Lubricating oils and solvents should be recycled or reclaimed. Returning used liquid products from gas plant treatments to vendors is the preferred method of disposing of glycol, amine, sulfinol, and caustic solutions. Other solid wastes such as filter media, iron sponge, molecular sieves, sulfur and sodium slurries should be handled as solid waste, after being drained of all possible liquids.

Cooling tower blowdown, boiler water, scrubber liquids, and steam generator waters become contaminated with salts. These waters should be disposed by Class II injection or in commercial disposal pits. Scale from downhole equipment, tubing, piping and heat exchangers usually consists of barium sulfate, iron sulfide, calcium carbonate, and can be managed as non-hazardous waste (API EGD, 1989). New and pending regulations for NORM should be considered in dealing with scale deposits.

CHAPTER 5

ENVIRONMENTAL SITE ASSESSMENT

FOR PETROLEUM PROPERTIES

Introduction

Petroleum professionals recognize a need to avoid involvement with environmentally contaminated properties and to manage problems at properties where they own responsibility. Environmental site assessment and site characterization can be used by anyone interested in the environmental condition of an oilfield property. In every case, environmental professionals must efficiently develop and clearly report information necessary to make technical judgements about the environmental condition of a property.

The American Society For Testing And Materials (ASTM) defines Environmental Professional as "a person possessing sufficient training and experience necessary to conduct a site reconnaissance, interviews, and other activities, ... and having the ability to develop conclusions regarding recognized environmental conditions ..." (ASTM E 1527-93, p. 5). The purpose of this Chapter is to outline major elements and protocol for environmental site assessment of petroleum exploration and production properties.

Planning

The planning process should anticipate needs, devise efficient methods, and present a plan. The client's objectives, along with standard professional practices should be defined during the planning stage. Protection of human health and the environment, technical accuracy, and cost control should be considered to develop the best approaches.

A conscious process of planning work and estimating costs is crucial for efficient site assessment. This process must be applied continuously, and repeatedly throughout each Phase. The phased investigation process follows a basic outline:

Plan Work
Execute Plan
Analyze Data
Plan Next Phase
Report and Propose
Repeat

The Phase 1 objective of an environmental site assessment is to gather basic information and determine whether the site has environmental contamination. If contamination is discovered it must be delineated and quantified in Phase 2. Phase 2 may also include an assessment of risk to human health and the environment. Phase 3 entails remedial systems design, and remediation of environmental pollution which presents unacceptable levels of risk. Obviously, every person interested a site will not have an obligation to clean up a property. However, if an owner does not plan to follow through with the whole process, they may not gain from the assessment and may create additional liabilities by virtue of knowledge of pollution.

Guidance

In recent years considerable guidance has been published for Phase 1 real estate environmental site assessments. Many of these publications are listed in the bibliography of this paper. Particularly relevant are ASTM E 1527-93 and ASTM E 1528-93. These guidance documents "...define good commercial and customary practice in the United States of America for conducting an environmental site assessment of a parcel of commercial real estate with respect to the range of contaminants within the scope of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and petroleum products. As such, this practice is intended to permit a user to satisfy one of the requirements to qualify for the innocent landowner defense to CERCLA liability" (ASTM, 1993, p. 1).

The original stimulus for developing environmental site assessments for real property was recognition of the risk presented by Superfund (CERCLA) liability. Environmental site assessments allow employment of the innocent landowner defense provided by the Superfund Amendment and Re-authorization Act (SARA) of 1986. Even though petroleum properties are not commonly polluted with CERCLA hazardous substances and petroleum exploration and production (E&P) wastes are exempt from RCRA designation as hazardous wastes, CERCLA guidance is the basis for all environmental site assessments.

Phase 1 Environmental Site Assessment

A Phase 1 investigation should present basic information and attempt to confirm or deny environmental contamination at a site. Most environmental site assessments begin with review of public records to determine current and prior land uses. Public records of registration and environmental compliance should be reviewed. Determining compliance with environmental regulations is a process called an "environmental audit", but is also part of an environmental site assessment.

Initial information to be collected is essentially the same regardless of the intent of the client. Similarly, the process of investigating a one well site, represents the process used to assess any package of individual sites.

Typical Oklahoma oilfield sites are not likely to be involved with hazardous substance and real estate environmental problems that are anticipated in most environmental site assessment guidance. However, such a possibility must be considered because of Oklahoma's widespread producing fields. Well-sites in the giant Oklahoma City field occupy industrial, commercial, and residential areas. Oklahoma's listed Superfund cleanup sites include refineries which were located in oil producing provinces in order to take advantage of nearby oil production. In many parts of the state, urban areas have over-run producing areas, or field development has moved into town where geologic drilling prospects were favorable.

Environmental professionals must determine an appropriate area of review (AOR) for the assessment. Uses of the subject property and surrounding properties should be considered. ASTM guidance listed in Table II indicates that in most instances, a one mile radius area of review is appropriate for Phase 1. Special circumstances, such as unusual hydrologic conditions, or injection wells may dictate a larger AOR, since their influences can extend beyond property boundaries.

Environmental professionals must be innovative in order to enhance and supplement standard environmental information sources. Utilize knowledge of process and specific industry records. The opportunity for overkill in the accumulation of Phase 1 background information is obvious. Environmental

TABLE I

COMPONENTS OF PHASE I ENVIRONMENTAL ASSESSMENT
(ASTM E 1527 - 93)

Records Review

Site Reconnaissance

Interviews

Evaluation and Report

TABLE II
STANDARD ENVIRONMENTAL RECORD SOURCES:
FEDERAL AND STATE (ASTM E 1527-93)

	Approximate Minimum Search Distance, miles
Federal NPL site list	1.0
Federal CERCLIS list	0.5
Federal RCRA TSD facilities list	1.0
Federal RCRA generators list	property and adjoining properties
Federal ERNS list	property only
State lists of hazardous waste sites identified for investigation or remediation(NPL and CERCLIS equivalents)	
State landfill and/or solid waste disposal site lists	0.5
State leaking UST lists	0.5
State registered UST lists	property and adjoining properties

professionals should design assessments to fulfill due diligence, and to be efficient with client resources.

Records Review

Practically reviewable data is defined by ASTM E 1527-93 (p. 5) as that data which yields information relevant to the property without the need for extraordinary analysis of irrelevant data. Practically reviewable data is provided in a manner and form that allows retrieval by reference to the location of the property or a geographic area. ASTM explains that when a source generates so much data that it cannot feasibly be reviewed for impact upon a specific property, it is not practically reviewable. Cost and time constraints may be taken into consideration to determine whether information is reasonably ascertainable.

Necessary Phase 1 information documents the property's history and indicates whether it may be environmentally contaminated. Commercial record search services are available, and may be worth the expense, especially for researching property packages or large areas.

Particularly relevant initial records for oilfield sites include the Oklahoma Corporation Commission (OCC)completion reports for wells on the property, OCC Form 1002A. This form is the best single source for basic well information, including legal location, operator and well names, API number, dates of drilling and production, total depth, producing and show zones, re-completions, spacing order numbers, field names, and other information.

For producing wells be sure to check for a current operator number. All current operators must have an OCC/OTC Operator Number assigned by the Oklahoma Tax Commission to operate in the State of Oklahoma. The American Petroleum Institute Number for each well can be obtained from Petroleum Information, if not on other records. If there is reason to believe a well may be plugged and abandoned, obtain the plugging record, OCC Form 1003, as an initial record.

A good source of information about known environmental problems at a site is the OCC District Office. District Offices maintain records of complaints about a site, filed by legal location and by Incident and Complaint Reports (OCC form 1085). District Offices also maintain records of Pollution Docket Complaints the OCC may file against a well operator, and any Orders that issue from these hearings. Oklahoma Corporation Commission Oil and Gas Conservation Division District Offices are currently located in Bristow, Kingfisher, Duncan, and Ada.

Sensitive environmental issues for oilfield sites include Class II underground injection wells. OCC form 1002A should show information about wells completed as injectors, and can be checked against the Class II lists. It is possible that a well may have been converted to injection without the form 1002A being updated. The OCC maintains books of known Class II wells by county, legal location, operator, and order number. The OCC also maintains a list of the approximately 140 commercial Class II wells in the state. This list also provides Field Inspector comments which can be helpful. Commercial Class II well information can be accessed on computer by OCC personnel. Use the county and legal location, then operator and well name to check any specific site or well. If details about specific Class II injection wells are needed, the Annual Fluid Injection Report (Form 1012A) outlines annual injection operations and is required to be submitted by April 1 each year. Mechanical integrity test (MIT) results are reported on OCC form 1075.

Pits are another area of environmental concern for oilfield properties. Locations of drilling pits may be indicated on the OCC Intent to Drill form, but lists or specific forms are not available for older sites. Non-commercial pit locations on a site can more likely be determined using aerial photographs, site inspections, and interviews. Records of earthen pits, such as OCC Form 1014, will not be available for wells drilled prior to the 1980's. A list of commercial mud disposal pits is maintained by the OCC and should be checked as part of the basic records review.

OCC Pollution Docket Orders should be considered practically reviewable and basic information. Other Commission Orders that created Field Rules can be important when they allowed practices in a certain field that were not allowed state-wide at that time. Field Rule Orders are more important prior to the 1970's, before environmental regulations became more uniform (Jackson, B., personal communication 1993). Other site specific OCC orders called Spacing and Pooling Orders can provide useful information for skilled investigators, but they should not be considered basic Phase 1 information.

Other records to consider are listed in Appendix II, roughly in decreasing order of typical importance. Site specific conditions should be considered in determining which specific information is relevant.

Maps

The single most important piece of information for any environmental site assessment is the site location. Correlate the legal location from lease or title records with the OCC form 1002A, Herndon, and topographic map. Sets of county road maps marked with the US Public Land Survey System (Section, Township, and Range) are available from surveying companies.

Geologic setting and hydrology of the site and area are important variables. Excellent maps to aid hydrologic assessment include the Oklahoma State Health Department maps showing principal groundwater resources and recharge areas in Oklahoma, compiled by Kenneth S. Johnson, OGS, 1983, and the Oklahoma Geological survey map GM-28, Oklahoma Oil and Gas Fields, M. R. Burchfield, 1985, revised 1991. Both of these maps are scaled 1:500,000. The OSDH maps outline principle aquifer recharge areas and alluvial and terrace deposit aquifers. The oil and gas field map shows outlines of 3,083 active fields and 35 abandoned fields. It also includes a list of field names and legal locations. The scout card and some production records for a well will usually provide a field name also.

Extensive information which can be utilized by geologists is available from the Oklahoma Geological Survey (OGS) at:

100 East Boyd, Room N-131
Norman, Oklahoma 73069
phone (405)325-3031

OGS Hydrologic Atlases are especially helpful for environmental investigations, and were used as reference for the OSDH hydrologically sensitive area maps. They provide vital information for a hydrologic appraisal. Locations of water wells, depths to water, well yields, and water qualities are presented at a scale of 1:250,000. This scale allows more detailed examination of specific sites than the OSDH maps. A list of hydrologically sensitive outcrop areas is also available. Nine Hydrologic Atlases cover the entire state. Each atlas covers one quadrangle, one degree of latitude by one degree of longitude.

A more detailed oil and gas map than the GM-28 is necessary for accurately locating particular leases and wells. In Oklahoma, the Herndon map is an industry institution. Herndon maps are normally scaled at one inch equals one mile. They provide a U.S. Public Land Survey System (section, township and range) base map showing individual well locations. Many of the wells are also coded with information on reported formation tops, total depth, producing zones, initial production data, and information on shows and tests. Some of this information was obtained from scout cards, form 1002A and company reports. Dry holes and abandoned producers are also shown. Nearly all domestic U.S. petroleum producing regions have local mapping services, like Herndon, which investigators should seek out. Other companies, such as Petroleum Information, Geomap, and Mid-Continent Maps also offer good Oklahoma base maps.

After basic information about the location and use of a property is documented, more specific site conditions can be researched. Refer to Chapter IV for discussion of principle technologic issues of petroleum exploration and production; drilling operations, earthen pits, product and wastes. These activities must be addressed because they are common and expected. Use aerial photographs and topographic maps to identify pits, well head, and tank areas. Old pits may appear as square ponds. Evidence of stained, stressed or non-vegetated areas, or eroded areas should be noted. These features help orient the site investigation and are probable sampling locations. It will be easier to locate equipment features on active rather than abandoned sites. Speaking with the landowner and neighbors is often a good way to gain information on the location of various features.

<u>Owner/Operator Records</u>

Operators usually keep detailed records on their well sites. If these records are reviewable, they should be considered. Company records are the most difficult to access, due to confidentiality. Basic information will include drilling, completion, and production reports. Product or waste releases may be recorded in these files. Working interest owners may have abbreviated versions of well-records, and royalty owners will generally maintain only sales records.

Petroleum operators are required to document their environmental regulatory compliance. If an investigator can access these records, they may provide important information for the property assessment. Refer to Chapter III for the regulatory basis of the information operators are required to maintain. The most common of these records are;

1)Spill Prevention Control and Countermeasure Plans

2)NPDES Stormwater Permits

3)OSHA Hazardous Communication

4)SARA Title III Hazard Communication

5)Clean Air Act Permits

6)Environmental Studies or Assessments

Employers are required by OSHA to determine any hazards associated with chemicals in the workplace (29 CFR 1910.1200). They must have a written hazard communication program and employee training. The program should list all hazardous chemicals, and include procedures for compliance with material safety data sheets (MSDS), labeling and training requirements. The MSDS for chemicals used on the site should be available to employees who work on the site. This information may be requested of the lease operator in order to know what hazardous materials are currently used, or have been used on the location.

Oklahoma state law requires special signs at locations where hazardous materials are used or stored. A good hazard communication program includes placement of these signs on lease equipment, such as separators, pressure vessels, and stock tanks. Container and drum contents should always be clearly marked, and have appropriate warning labels (Turner, 1991).

The Superfund Amendment and Reauthorization Act of 1986 (SARA) was presented in Chapter III. This Act created the innocent landowner defense against CERCLA liability. It also created regulations requiring industry to develop emergency response plans and to report to local planning committees on their materials and facilities.

Section 311 and 312 of SARA Title III are most significant for the petroleum industry. They require (40 CFR 355) that chemical lists and Material Safety Data Sheets (MSDS) are reported to Local Emergency Planning Commissions and annually inventoried. The chemicals which must be listed are any that appear on the following regulatory lists:

40 CFR 355 Extremely Hazardous Substance List

40 CFR 302 CERCLA Hazardous Substance List

40 CFR 372 Toxic Substance List

29 CFR 1910.1200 OSHA List

Section 311 filings have been required since 1988. Oklahoma requires filing with the OSDH which is now part of the Oklahoma Department of Environmental Quality (ODEQ). Environmental professionals should consider review of these filings since they may be specific about the materials which have been on the site.

Site Visit

At least one site visit should be included in all Phase I environmental site assessments, to obtain information indicating the likelihood of identifying recognized environmental conditions (ASTM E 1527, p. 12). During the site visit, inspect areas with the highest probability of contamination. Investigate features of concern that were identified on aerial photographs, topographic maps, or in the records review. Document the condition of these areas with notes, photographs, or video-tape.

Current as well as past uses of the property should be detailed in a report. Hazardous substance and petroleum treatment, generation, storage, and disposal activities should be identified and described where they are observed in the site visit, or found through records and interview searches (ASTM E 1527).

If petroleum, hazardous, or deleterious substances may have been stored or released on the site or nearby properties, use the site visit as an opportunity to consider transport risk. Be perceptive, observe the lay of the land, soils, drainage patterns, and surface waters. Surface topography is the initial indicator of shallow groundwater gradient. Surface geology must be considered and integrated into the information gained from records review, including the basic reference maps. Inspection may reveal excavated or filled areas that can greatly influence contaminant transport direction and velocities.

An investigator should understand the function of equipment at each site. American Petroleum Institute publication Document No. 811-10850 (1989), Onshore Solid Waste Management In Exploration And Production Operations, provides a section on oilfield waste generating processes and equipment.

The standard production equipment set-up consists of the wellhead, oil/water separator, and tanks to hold crude oil and formation water separately. Systems can be much more elaborate. In a developed area, well-to-well gathering systems with centralized tank batteries, product treatment systems, compressors, and waste water injection wells are common. Buried gathering lines can be lengthy and have potential for leakage. Abandoned lines may still contain significant volumes of the material they transported, generally crude oil or salt water.

If buildings are a part of the property, a walk-through inspection should be performed. Structures on the property should also be detailed. Accessible common areas used by occupants should be observed. Uses and conditions of the property should be identified to the extent that they may be visually and physically observed, or to the extent that they are identified in interviews. Roads on and adjoining the property should be described. Potable water supplies and sewer systems for sanitary and storm water should be identified and detailed as to age and receptors if possible (ASTM E 1527-93).

Adjacent property uses, current and past, shall also be identified in the report if they may indicate environmental conditions in connection with the environmental condition of the subject property. Similarly, if information from visual or physical inspection, or records, or interviews provides relevant information about current and past uses of the surrounding area, it should be included in the report.

ASTM 1527 E further sets forth the standard practice of environmental professionals to investigate underground storage tanks (UST's), storage tanks, drums, unidentified containers, electrical transformers potentially containing PCB's, pits, ponds or lagoons, stained soil and pavement, stressed vegetation, solid wastes, trash, water discharges, wells, and septic systems.

As discussed in Chapter III of this paper, ASTM clarifies that the inclusion of petroleum products within an assessment is not due to the inclusion of petroleum products under CERCLA liability, but to the current custom and usage to include an inquiry into the presence of petroleum products when doing an environmental site assessment of commercial real estate (ASTM E 1527 - 93).

Interviews

Persons who can provide necessary information about recognized environmental conditions in connection with the property should be interviewed. Interviews may properly be carried out in person, by telephone, or in writing and should be accurately documented. If possible, ask the owner to identify a person with knowledge of the uses and condition of the property. In the case of oilfield properties, the site manager will usually be the pumper, operations engineer, or company geologist. Landowners are also good sources of information. The environmental professional may try to schedule a site visit when the site manager, or most knowledgeable person can be present.

Investigators should be courteous, and recognize that while they have an obligation to ask questions about the property, in most cases the person to whom the questions are addressed will have no obligation to answer them (ASTM E 1527, p. 15). Persons being interviewed, especially operating company personnel, should be asked if they are aware of the existence of any potentially relevant documents, such as environmental assessment reports, environmental audit reports, environmental permits or registrations, material safety data sheets, community right to know plans, safety plans, SPCC plans, hydrologic reports, environmental agency reports or notices, or geotechnical reports.

Prior to the site visit, the owner and site manager should be asked whether they know of any; (1) pending, threatened, or past litigation relevant to environmental conditions; (2) pending, threatened, or past administrative proceedings regarding the property; (3) notices from any government entity regarding any possible violation of environmental laws or possible environmental liability (ASTM 1527 E).

Local government officials may have knowledge of recognized environmental conditions of a site. Environmental professionals must frame the questions and locate relevant government representatives. For Oklahoma petroleum properties, OCC pollution abatement staff, including district oil and gas field inspectors are the logical choice. For additional information, the former Water Resources Board or Department of Health, now within the ODEQ, may have knowledge about problem sites or areas.

Sampling Requirements

Phase 1 environmental site assessment guidance has become standardized due to broad interest in CERCLA due diligence for commercial real estate properties. Real estate environmental assessment guidance is useful for petroleum property assessments. However, the complexity of petroleum properties and the industrial use of the property mandate a more in-depth approach. A conventional Phase I real estate audit, without sampling soil or groundwater, is not appropriate inquiry for most petroleum sites.

For petroleum exploration and production sites, environmental professionals should include environmental sampling in order to confirm or deny contamination, and to determine whether further site characterization is justified. An initial site characterization method is needed.

When possible, obtain regulatory agency guidance for methods and action levels from the OCC Oil and Gas Division regulations in OAC 165:10. Current Oklahoma Corporation Commission (OCC) regulations do not specify action levels, cleanup levels, or lab methods for oilfield sites.

Lack of allowable contaminant level guidance is a problem for scientists working with oilfield environmental concerns. Regulatory analogies can be used as reference. Oklahoma Corporation Commission petroleum storage tank regulations are appropriate because the concern is petroleum, not classified as a hazardous substance or hazardous waste as with RCRA Subtitle C and CERCLA guidance. Commission regulations in OAC 165:25-3, and API Publication 1628, <u>Guide to the Assessment and Remediation of Underground Petroleum Releases</u>, as well as federal regulations in 40 CFR 280, provide useful reference. Detailed technical guidance is available in other EPA documents.

The geologist or environmental professional must be reasonable in their approach to environmental sampling. Always sample for components of the substances in the system. Samples should be taken from areas most likely to be contaminated, such as below tanks, within the berm, down-gradient areas including surface water bodies, around the well head, loading ports and clean-out ports, and along pipeline trenches. Obtain samples from pits and surface waters. Check down-gradient areas for non-vegetated, denuded conditions, or moonscapes. Barren or eroded areas may indicate salt water or crude oil contamination. Plan to obtain comparative samples from areas which are not suspected of contamination, in order to establish background levels and create a frame of reference for action levels. Refer to Appendix III for general sampling guidance.

Common Sampling Parameters

To run random suites of laboratory analyses is economically unreasonable, so consider the cost of collecting and analyzing samples. Stay aware of the central objective, which is "appropriate inquiry", and be prepared to justify laboratory method choices. Always research the substances to be handled and use all appropriate safety precautions. Refer to Appendix III for standard oilfield sampling parameters.

The most common oilfield pollutants are salt water, crude oil, condensate, drilling fluids, treating chemicals, fuel and lubricating oils, and naturally occurring radioactive substances. OCC regulations OAC 165:10-1-2 define deleterious substances as any chemical, salt water, oil field brine, waste oil, waste emulsified oil, basic sediment, mud, or injurious substance produced or used in the drilling, development, production, transportation, refining, and processing of oil, gas and/or brine mining.

Sample for common oilfield substances using low cost, reliable methods. Laboratory tests for pollution indicators include total dissolved solids (TDS) / total soluble salts, benzene/toluene/ethylbenzene/xylene (BTEX), total petroleum hydrocarbons (TPH), pH, chloride, barium, arsenic, chromium, fluoride, zinc, lead, and the toxicity characteristic leachate procedure (TCLP). Other data that can be obtained in the field and by laboratory testing includes pH, temperature, and specific conductance (SC).

Inform the laboratory of contaminants suspected of being present. Indicate the type of hydrocarbon for the Total Petroleum Hydrocarbon (TPH), for example gasoline, diesel, or oil. If sampling a crude oil release, indicate whether it is fresh or old crude oil (Southwell Labs, 1993). The OCC Fuels Division currently recommends EPA method 8015 for BTEX and EPA method 8020 for TPH (OAC 165:25-3). EPA method 418 for TPH is not approved (OAC 165:25-3-71).

The best reference on laboratory methods is EPA Publication SW 846. This four volume set of references is available in major libraries. In most situations it is reasonable to rely upon an OWRB Certified lab for guidance on specific methods. Results of sample analyses will dictate whether additional investigation and remediation is necessary, so choose methods and contractors carefully.

Special Situations. Any environmental assessment may present unique situations. For example, a client company desired to drill a well in a developed part of Oklahoma City. An abandoned electrical generating plant site provided the only feasible drilling location. Prior to becoming involved with operations on the property, a baseline environmental audit was recommended. The client needed to establish the condition of the property prior to becoming involved through drilling operations. Because the site had been used for electrical generating, transformers containing PCB's were suspected to have been used on the site. In this case, a laboratory check for PCB's in soil and water was added. Sediments in the cooling pond and in the creek that carried runoff water were sampled to examine potential contaminate buildup.

Handling of Samples

Environmental professionals should always document field activities with sampling logs, protect sampling equipment prior to use and clean non-dedicated sampling tools after use, follow chain of custody procedures, use QA/QC protocol for field and laboratory (EPA, TEGD, 1986).

For oilfield samples, always refrigerate samples as soon as possible to preserve volatile components. Biochemical alteration can be retarded by using preservatives such as sulfuric acid. References such as EPA

SW 846 and the RCRA TEGD elaborate upon sampling protocol and quality control.

Sampling of Drums. Position the drum upright and allow contents to settle. Allow gas pressure to release then sample through the bung hole. Drums in a condition to be moved should be segregated and sampled by contents.

Sampling Containers or Sacks of Powder or Granular Waste. Take precautions and wear proper safety gear. Collect a composite sample, sample randomly if appropriate.

Sampling of Storage Tanks. Always have a company representative and a helper if sampling tanks. Due to density variations, collect a sample from the upper, middle, and lower sections of the tank, then combine for a composite. If you have concerns about specific substances, stratified samples may be attempted.

Sampling a Pit. Sample the pit contents. Standing water around a pit should be sampled to check for seepage. If a release is suspected, sample up and down stream from suspected sources.

Soil

Select an appropriate method to sample soil in former pit areas, in the tank area, and around the wellhead. Contaminated soil will often be expressed in non-vegetated areas, which can be detected on aerial photographs. Oil spills are listed as one of the four most common causes of saline and alkaline soils in Oklahoma (Johnson, G. OSU Extension Facts No. 2226). Use of earthen pits, and spills account for most soil contamination at an exploration and production site. Crude oil spills and leaks from years of cumulative operating practices are possible at older sites. Soils remaining after pit closure may be impacted with salt or drilling fluids, while poorly vegetated areas at a reclaimed site may simply be due to a lack of topsoil, or to improper soil management practices.

To collect soil samples, grid areas of common concern, sample the grid and combine for a composite sample. Use a scoop for samples as deep as 4 inches and appropriate augers for greater depths. Waste pile samples may be similarly combined to form a composite sample. Obtain soil samples from clean areas to establish background levels. In the absence of regulatory action levels, background comparison is a good place to start.

The Oklahoma Corporation Commission has established guidelines for soil contamination action levels at spill sites. For the OCC, greater than 2500 ppm Total Dissolved

Solids (TDS) "indicates a need for removal or restoration...." (OCC Guidelines, 1992). Most laboratories use the term "total soluble salts" for soil analysis, rather than "total dissolved solids". The Cooperative Extension Service, Division of Agriculture at Oklahoma State University has published a guidance document on slick spots and salty soils. OSU Extension Facts No. 2226 defines saline soils as containing at least 2600 ppm soluble salts and electrical conductivity of 4,000 micromhos/cm. Alkali soils contain 15% or more exchangeable sodium percentage and commonly have a pH of 8.5 or above. According to this publication:

> It is best to sample during a dry period of the growing season when affected areas of the field can easily be identified by the poor crop growth. Samples should be taken at least one week from the last rain or irrigation and only the top three inches of soil should be sampled. Several small samples of the affected area should be combined in a plastic bucket and mixed to get a good sample. About one pint of soil is required for the test which is done by the OSU Soil testing Laboratory.

Other soil parameters referenced in OAC 165:10 include the sodium adsorption ratio, defined as

SAR =Na(ppm)-23.0 / 0.5[(Ca(ppm)-20.02)+(Mg(ppm)-12.16)]

and the exchangeable sodium percentage

ESP=100(-0.126+0.01475*SAR)/1+(-0.0126+0.01475*SAR).

Surface Water

Obtain samples from bodies of surface water near the site. Sample streams both above and below discharge points. It may be reasonable to sample subsequent receiving streams. API defines fresh water as having TDS of 3000 ppm or less, equivalent to approximately 4 mmhos/cm.

Oil concentrations in an effluent which are greater than 10 ppm are visible as globules and even less oil will produce rainbow streaks on water (Wardley-Smith,1979, p. 23). Water which has been in contact with fresh crude oil or its lower fractions, as from an oil water separator, may have extracted significant quantities of potentially toxic hydrocarbons.

Standard solubilities for benzene are 820 ppm, for toluene 470 ppm, and 360 ppm for pentane in the temperature range 16-22 degrees C. Benzene and toluene are lethal to fresh-water fish at 10 to 400 ppm, depending upon species and test conditions. Naphthenic acids, which are minority constituents of crude petroleum and are readily absorbed by water, kill fish at 5 to 120 ppm. The test for dissolved initially. Failure to do so may cast doubt upon the due diligence of the environmental investigation.

Although significant effort, expense, and attention is focused on hazardous substances, the most pervasive oilfield pollutant is salt water. Formation water, connate water trapped in rock along with petroleum, is produced with the oil. Usually these waters are brines that have the potential to contaminate fresh water aquifers.

The OCC uses the term lowest known treatable water in regulations for well design. The OCC defines this depth with electric log analysis, but also as 10,000 ppm TDS. The OCC Oil and Gas Division maintains a database which supports mapping the base of treatable water, and makes this information available to the public. Checking the current data may show that old wells have surface casing strings which are too shallow to protect treatable water zones. Hydrogeologists should not rely totally on the OCC maps, and should endeavor to develop more site specific information if this factor is of concern.

The API Environmental Guidance Document specifies 3000 ppm TDS (approx. 4 mmhos/cm conductivity) as a maximum level for designation as fresh water. The OCC uses the term treatable water meaning subsurface water in its natural state, useful or potentially useful ... and contains less than 10,000 mg/liter TDS or less than 5000 ppm chlorides (OAC 165:10-1-2). Treatable water includes but is not limited to fresh water.

Some areas of Oklahoma have naturally high background levels of chloride and sulfate due to surface geology. Such areas occur along the Cimarron River in Harper, Woods, and Woodward Counties and in the southwestern part of Oklahoma in Harmon, Greer, Jackson, Kiowa, and Tillman Counties where the Blaine Gypsum and dog Creek shale crop out (Pettyjohn, White 1986, p. 47). The Salt Plains areas of Alfalfa and Grant Counties have similar characteristics.

The Federal Safe Drinking Water Act established primary and secondary drinking water standards for the nation's water supplies (40 CFR 141). The OSDH set forth these values in their Public Water Supply System regulations, and they are also established as Underground Storage Tank (UST) site characterization action levels (OAC 165:25-3-74.1). Refer to Appendix IV for water classifications.

Groundwater sampling and contaminate plume delineation can be complex and expensive. If surface spills, releases, or contamination are of concern, groundwater characterization should begin with the uppermost aquifer. The uppermost aquifer may be difficult to identify. It may consist of a shallow perched lens of porous material encased in shale, such as in the Hennessey Group of central Oklahoma. In other areas, such as the Enid alluvial aquifer area or along river valleys, the uppermost aquifer may be the principle drinking water aquifer for a large area. In western Oklahoma, the Ogallala formation is a principle drinking water aquifer where the uppermost saturated interval may occur at depths greater than 150 feet. In all of these examples, the assumption is that contamination will generally sink and be carried by precipitation vertically downward until it encounters a water saturated interval. In the uppermost aquifer, contamination will tend to spread laterally downgradient with groundwater transport, creating a contaminate plume.

For UST initial site characterization following confirmation of release, OCC guidance now requires drilling to the uppermost aquifer or 100 feet deep, if soil contamination is above Category I action levels. A new proposed policy will require drilling with field screening, to a depth of uppermost aquifer, or two sampling events beyond clean field screening, or 50 feet, when TPH exceeds the action level in soil (50 mg/l) but is less than Category II levels (500 mg/l) and only when benzene levels are not above action levels (0.5 mg/l). This type of approach may be appropriate for oilfield site characterization. When utilizing this approach, the deepest soil sample should be laboratory analyzed.

Investigators may become involved with properties where situations are more complex than a surface release. Down-hole mechanical failures or geologic structure may allow saltwater, oil, natural gas, or treating fluids to be injected into fresh water zones. Changes in hydraulic gradient from injection practices may transfer through deep zones to encounter uncased holes where formation water can rise into lower pressure fresh water zones. High volume water pumping wells can exert withdrawal cones of depression which alter local groundwater gradients. Such situations can be very complex and require expert hydrologic interpretation.

Surface water may consist of groundwater discharge in some areas. Especially during arid months, stream flow may contain of a high percentage of groundwater (Pettyjohn, 1991). During Phase 1 sampling, consider potential for up and down stream flow to reveal groundwater contamination. Compare samples, source and receiving streams relevant to your site, and hydrologic atlases for indications of groundwater quality in the area.

Analysis and Interpretation

Action Levels

Action level means the level of a certain contaminant which dictates a need for corrective measure study, site characterization, or further consideration. Contamination exceeding action levels indicates a potential threat to human health or the environment which may require further study (FR, July 27, 1990, p. 30814). Because oilfield action levels are not currently provided by the OCC, analogies must be drawn from other regulatory publications. Storage tank regulations which deal with petroleum have already been listed. The Federal Register of July 27, 1990 (Vol. 55, No. 145) provides proposed rules for solid waste management unit corrective actions, that can also be referenced. From these sources, preliminary soil and groundwater action levels are presented in Appendix V.

Investigators should check with the OCC and OSDH/ODEQ for guidance on action levels. Action levels should be distinguished from cleanup standards, that are determined later in the corrective action process (FR, July 27, 1990, p.30814). Contamination above action levels does not automatically require active remediation.

Development History

Some of the most important information from Phase 1 records are dates of operation, which allow documentation of the property's development history. Environmental protection has evolved and dates of advancements that have an effect on environmental protection can be used as risk indicators. When records show a certain operation was performed prior to a significant advancement, risk is higher. Timing of events at a site may provide direction for the assessment.

Wells drilled prior to 1940 are relatively high risk. Environmental protection was minimal during this early phase of the industry. Modern cementing methods in use after 1940 lower the risk of environmental problems due to poor cementing (API, 1993). Approximately 38% of Oklahoma's total wells were drilled before 1940.

The 1940's brought OCC rules for earthen pits, and some Field Rules dealing with environmental protection. More advanced cementing techniques and casing programs became common after 1940. The 1955 Deleterious Substance Act strengthened environmental protection, especially by restricting the use of brine disposal pits. Technology and operating practices improved and modern rules for pits, casing, cementing, and plugging were created in the early 1970's. Environmental regulation accelerated in the early 1980's with recognition of hydrologically sensitive areas and pit liner requirements. Waste minimization programs, elimination of hazardous substances, and liability consciousness allow modern operations to present low environmental risk.

Neither regulatory nor technologic factors can protect the environment against accidents, or illegal practices. However, consideration of development history can help focus the assessment on high risk practices which would have been common for sites of certain time periods.

Comparable Value Analysis

The Innocent Landowner Defense specifically references "the relationship of the purchase price to the value of the property if uncontaminated" as a test for known contamination (42 USC 9601(35)(A)). A severely discounted price may be the result of contamination known by the seller. While this test is difficult to utilize, price should be considered and a severe discount should raise questions of marketability.

In the case of petroleum producing properties, market value is especially difficult to determine, compared to more traditional commercial real estate, where more extensive comparable trades may exist. Consultation with experienced petroleum acquisition professionals will be required in order to make an adequate judgement of value.

Some value factors which may be considered include:

1) Cash flow
2) Proved developed reserves
3) Current production rates
4) Proved undeveloped, "behind pipe" reserves
5) Nearby activity and property trades or comparative sales
6) Unproven potential, deeper zones or geologic ideas requiring new drilling or investment

A thorough examination of economic appraisal is beyond the scope of this paper, but numerous publications on the subject are available.

Phase 2 Site Characterization

Phase 2 site characterization should quantify and delineate soil and groundwater contamination confirmed in Phase 1. Phase 2 site work requires environmental professionals to be more skilled in geoscience, than do environmental site assessments. API 1628, RCRA TEGD, and ASTM may provide useful guidance.

At sites where soil contamination is confirmed, a Phase 2 plan for delineating the affected area should be developed and executed. Soil borings are the most common method for delineation, although geophysical and probe type methods may also be appropriate. Use field screen techniques to delineate the area where allowable contaminate concentrations are exceeded, and back up field screening with laboratory analyses. Create isoconcentration maps and cross sections for contaminants of concern.

Phase 2 work should delineate contaminate transport, as well as establish background and run-on contaminant levels. Plumes should be delineated to the extent greater than allowable contaminant concentration levels. It is not usually necessary to delineate to areas with non-detect levels. However, without regulations for maximum contaminant levels to use as action levels, owners could be held to non-detect as a background level for some substances.

Down-gradient areas must be delineated for free phase and dissolved phase contaminates. At sites of historic contamination, detached plumes, or slugs may be transported from the site. Chloride contaminated groundwater plumes can be stratified due to density variation (Pettyjohn, 1971). Surface water may be groundwater discharge in some areas. Especially during arid months, stream flow may consist of a high percentage of groundwater (EPA, 1992). Recognition of the groundwater system allows economic field characterization of groundwater contamination. Examine streamflow, up and down-stream from suspect sources. Compare temperature and salinity for source and receiving streams relevant to your site, for indications of groundwater contamination.

Phase 2 soil and groundwater characterization design is site specific and is beyond the scope of this paper. Tremendously complex situations can occur at oilfield pollution sites. Most environmental professionals are not trained for interpretation of complex oilfield sites. It may be necessary to consult with experienced professionals in order to interpret the pathways of contaminant migration, the extent of a problem, and methods for corrective action.

Phase 3 Remedial Actions

It is beyond the scope of this thesis to provide guidance on complex interpretation or remedial system design. However, persons utilizing this guide should keep in mind that site assessment and site characterization are crucial ingredients for moving into those phases of risk management. True professionals will begin to interpret conditions and begin scoping remedial methods as information becomes available.

Remedial actions for oilfield environmental contamination may vary widely. If E&P wastes are present on a site, consult API publications and Chapter 3 for general waste management guidance. Remediation of contaminated soils begins with stopping the source of the contamination. A dig and haul approach can be used for localized contamination, such as a drilling pit. Owners should be cautious, and use good hazardous material management practices anytime they plan to transfer contamination from one site to another. The principle of strict liability may force the owner of generated wastes to retain liability, even when using a commercial disposal facility.

Suggested soil remediation methods from OSU Extension Facts No. 2226 and OCC Guidelines promotes steps to leach out the salts or sodium contamination in soils. Landfarming techniques are often appropriate for hydrocarbon contaminated soils (Shell, 1993).

Groundwater contamination, especially from salt water, can be very difficult to remediate. Pump and treat systems, plume containment, and natural flushing are options. Some hydrocarbons can be partitioned from water using air strippers and other methods used in petroleum fuel cleanups.

Petroleum contaminated environmental media can often be remediated using microbial degradation. Soil farming and water treatment using crude oil consuming microbes has been shown to work well. Biological cleanup methods for other pollutants are under study. Industry is working to develop more in-situ methods, which can improve effectiveness and lower costs.

Phase 4 Case Closure

If a site is being remediated under an Oklahoma Corporation Commission Order, cleanup levels will be specified in the order. Otherwise, until regulatory cleanup levels are established, case closure may occur whenever environmental professionals or owners feel they have concluded their obligations at a site. A property could move from a Phase 1 site assessment directly to Phase 4 closure if no contamination was confirmed at the site. Similarly, contamination may exist but be less than the appropriate action level, thereby supporting case closure with no further action.

If remedial actions have been undertaken, including monitoring during natural remediation, responsible parties should plan to continue monitoring for a reasonable length of time beyond "clean" readings. For most cases, five quarters of clean analyses should be adequate monitoring prior to closure. It is important to monitor through cyclic groundwater quality changes which may confuse attainment of clean levels.

Environmental risk assessment may also be used as a closure method, even if cleanup levels are not reached. Risk assessment methods are rapidly gaining favor with regulators and industry. Basic elements of any environmental risk assessment include hazard assessment, toxicity assessment, exposure assessment and risk characterization (Cohrssen, 1989). Risk management builds upon the baseline risk assessment by adding risk evaluation, remedy selection, risk management implementation, and achievement of acceptable risk reduction. Environmental risk assessment is an appropriate tool for defining environmental risk from petroleum sites. Environmental risk assessment guidance is becoming more available rapidly.

CHAPTER VI

CONCLUSION

Environmental assessment of petroleum E&P sites is a process that is feasible and currently used. Principle reasons to assess a property for environmental contamination include property management, buying or selling petroleum properties, property financing, or buying real estate associated with petroleum properties.

Actions based upon the environmental report will vary with the user. A buyer or lender may choose to apply a "drop dead" policy when aware of high environmental contamination risks associated with a potential acquisition. Alternately, a decision to negotiate terms or to accept a certain level of risk may be chosen. Operators may choose to conduct environmental assessment of their properties in order to establish baseline conditions and enhance regulatory compliance.

Oil and gas wastes and production by-products are specifically exempt from designation as hazardous waste (40 CFR Part 261). Petroleum is the only industry-wide exemption in RCRA subtitle C. This exemption has been challenged, as well as defended, by various factions during

RCRA re-authorization hearings. A fear of the petroleum industry is that oil and gas wastes may someday become subject to hazardous waste regulation under RCRA subtitle C. Another possibility is the creation of a new RCRA program specifically for petroleum E&P, something of a "subtitle D minus" (Jackson, B. personal communication 1993). If these changes were to occur in the future, RCRA and CERCLA laws and regulations may serve as guidance for environmental management. In terms of assessment design, this provides a worst case contingency plan.

Environmental site assessment guidance is available for real estate and for petroleum storage tank sites. Basic existing regulatory philosophies are being maintained in newer regulation. Petroleum operators can use this existing CERCLA and RCRA guidance in managing oilfield environmental site assessments.

The CERCLA laws, specifically SARA, have promoted the use of environmental real estate assessments. SARA provides for the innocent land owner defense, if evidence shows that proper inquiry into the property's environmental cleanliness was taken prior to acquisition. The SARA law provides managers with a performance standard. A performance standard is the essence of the intent of laws and regulations. Often laws and regulations are written in general terms, with very few specific technical design standards. Interpretation of intent is critical to define the performance standard.

The congressional conference report to the SARA legislation, excerpted in Chapter III, notes that the duty to inquire shall be greater as awareness of hazards grows. Environmental liability is a currently known hazard in the petroleum industry. Smart operators are using planned methods to lower their risk. Environmental site assessment plans must be developed to obtain the necessary information about environmental conditions, and allow risk based decision making for remediation.

The costs of performing assessments, as well as financial liability, are central issues. In the initial planning stages, project management, cost control, and funding of the site assessment must be addressed. If contamination requiring corrective actions is discovered, responsible parties must develop cost effective response strategies. Sharing the expense of investigation and remedial actions is desirable. Consensus building, risk assessment, and early settlement may be tools to allow these things to happen now. State administered cleanup funds must be considered for the near future.

Regulatory Compliance

Environmental site assessments may be used to check for regulatory compliance, and to work for continuous improvement in risk management. If pollution has been confirmed, an evaluation of regulatory compliance at the suspected time of release may be helpful in order to defend against liability for historic actions.

Risk Management

Responsibility for necessary environmental cleanup is an issue that may arise from site assessment. Reasonable and integral cleanup costs should be spread to all working interest (WI) owners of a property. Only in cases of incompetence or fraud should one WI partner pay disproportionately. Royalty owners are not owners in the production operation, and therefore should have no liability for environmental contamination. In fact, surface owners have a right to be protected from environmental contamination and degradation of their property. Royalty owners may have a right to be protected from environmental conditions which would inhibit further development of their mineral resources.

Existing standard Joint Operating Agreement forms do not address responsibility for environmental damages (Dowd, 1993). They do address conventional damages, which could conceivably be broadened to include environmental contamination. Development of standard lease terms regarding environmental responsibility could clarify these issues.

Need For Rulemaking

Oklahoma does not currently have oilfield environmental cleanup regulations for operators to rely upon. If operators do not know what levels and methods are appropriate, they cannot quantifyably lower risk on their properties. OCC regulations in OAC 165:10-7-5 instruct all persons to conduct their operations in a manner that will not cause pollution. Under this rule, operators and owners may conceivably be at risk of liability for any environmental contamination above background levels. A claim could be made that anything above non-detect justifies damage payments. An OCC rulemaking could follow the Texas Railroad Commission's lead in establishing regulatory guidance for interested parties to utilize when assessing properties.

Oklahoma needs a comprehensive regulatory structure to define when investigation is appropriate under a suspicion of release, to require reporting of problems which present risk to human health and the environment, outline proper methods of investigation, and promote risk based remedial action. As suggested in Chapter V, the regulatory structure of UST corrective actions may be used as an outline for oilfield cleanup regulation.

Existing OCC pollution abatement regulations could be broadened to define standard testing parameters, action levels, and maximum contaminant levels for cleanup.

Contamination above action levels does not automatically dictate a need for active remediation. Case activation may occur when action levels are exceeded, yet the case may not require further action, if levels are below the risk based cleanup category levels for the site. It is interesting to note that OCC action levels for petroleum UST cases are lower than the action levels proposed for solid waste cleanups by the EPA (FR Vol. 55, No. 145, Appendix A). Yet the majority of Oklahoma UST cases fall into a cleanup category which allows case closure, above the action levels listed by EPA.

Tiered cleanup categories, based upon risk sensitive factors, should be developed with industry cooperation. Patterned after the UST regulations (OAC 165:25-3-74.1 and OAC 165:25, Appendix J and K) sites with high risk factors such as nearby water supply wells, shallow groundwater, or hydrologically sensitive designation, would have more stringent cleanup levels than a site without high risk characteristics. Special considerations might include unplugged wells, inadequate casing, old injection wells, and other technical criteria. Special concerns also might include areas where historical activities have created high background levels of contamination over large areas. The OCC should encourage operators in such areas to form cleanup committees, and to characterize the field rather than the well site. These areas will probably deserve special considerations.

It is important for Oklahoma to move forward, encouraging and helping industry to manage environmental contamination problems in a reasonable manner.

Cost Control

As with all business projects, financial aspects of environmental site assessment are major issues. Environmental site assessment and environmental cleanup are services which can be managed in order to control costs, using basic approaches.

Persons buying these services should define what they need from the provider. When hiring environmental consultants and contractors, check references. Ask business associates for recommendations and for warnings. Determine what portions of the job may be sub-contracted. Ask about the relationship of subcontractors, and be just as concerned about checking their reputations. Developing working relationships with good contractors can allow cost reduction by more efficient work scheduling, economies of scale, and innovation. Always remember that a low cost job that does not fulfill your needs is no bargain, and that high cost is not the same thing as high quality.

Companies who will be involved in numerous site assessments may consider creating in-house expertise. In-house project managers can easily produce more in savings than they cost. Quality control of environmental projects also supports the need for in-house managers who can recognize methods to lower costs and produce truly cost effective reductions in owner liability.

Financing Oilfield Cleanup

Industry and regulators agree that some operators are active in evaluating their properties for environmental problems. The people of Oklahoma need for the energy industry to have an across the board motivation for performing site assessments. Industry needs a way to spread the costs of this added social responsibility.

Since government regulation has accelerated the necessity of environmental risk management, government will have to be involved in new methods of helping affected industries. Ideas such as tax credits for company expenditures on environmental cleanups, or a more limited credit for property buyers that remediate discovered contamination they did not cause, are currently being discussed.

In Oklahoma, it became apparent that new regulations for Underground Storage Tanks (UST's) were forcing many motor fuel retailers out of business due to the cost of petroleum release environmental cleanup. Because loss of these businesses would not be in the best interest of the people of Oklahoma, the State established an assessment on motor fuel at the wholesale level in order to provide an

Indemnity Fund to reimburse UST owners for eligible expenses incurred for environmental cleanup. The Oklahoma UST Petroleum Storage Tank Release Cleanup Program operates essentially like an insurance company, collecting premiums from the taxpayer, and processing claims through a staff of hydrologists, engineers, and accountants under authority of the Oklahoma Corporation Commission.

There is considerable interest from industry and state government in the idea of establishing an Indemnity Fund type of program for oilfield environmental cleanups. The precarious financial condition of the domestic petroleum industry, where an estimated 450,000 jobs have been lost in the past 10 years, dictates consideration of ways to share the cost of energy industry environmental problems. Society at large benefitted from the exploitation of Oklahoma's petroleum resources. It is fair to propose that society should share in the newly discovered environmental costs of this exploitation.

The Indemnity Program manages public funds. As such it is required to conserve those funds as much as possible, while achieving the objective of environmental cleanup. An Indemnity Fund approach is designed to overtly spread the cost of environmental cleanup to society. This approach practically eliminates the need for significant legal expenses.

Under an indemnification style program, the total project cost may be reduced to the extent that litigation over responsibility is rare. State administered programs can be designed to help owners of cleanup sites control costs, and reduce them through supervisory project management. State assisted cleanup could promote creation of area-wide methods, to share cleanup approaches. The indemnity fund approach also offers an opportunity for society to retain technical control of environmental cleanup, under statutory authority.

Call for Further Research

Industry and government should support empirical study of environmental conditions at Oklahoma oilfield sites. Research to assess, quantify, and geographically detail existing contamination is needed. Such a study should be supported both by those who believe there is little environmental impact from petroleum exploration and production, and those who fear industry practices create widespread pollution. Better databases will allow better risk assessment, and risk management.

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APPENDIX I

EXEMPT WASTES

Wastes listed as exempt from hazardous designation in EPA's Regulatory Determination submitted to Congress in June 1988 (Oil & Gas Journal, Dec 16, 1991, p. 52).

Produced water

Drilling fluids

Drill cuttings

Rigwash

Drilling fluids and cuttings from offshore operations disposed of onshore

Well completion, treatment, and stimulation fluids

Basic sediment and water and other tank bottoms from storage facilities that hold product and exempt waste

Accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments

Pit sludges and contaminated bottoms from storage or disposal of exempt wastes

Workover wastes

Gas plant dehydration wastes, including glycol-based compounds, glycol filters, filter media, backwash, and molecular sieves

Gas plant sweetening wastes for sulfur removal, including amine, amine filters, amine filtermedia, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge

APPENDIX I (Continued)

Cooling tower blowdown

Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)

Packing fluids

Produced sand

Pipe scale, hydrocarbon solids, hydrated, and other deposits removed from piping and equipment prior to transportation

Hydrocarbon-bearing soil

Pigging wastes from gathering lines

Wastes from subsurface gas storage and retrieval, except for the listed nonexempt wastes

Constituents removed from produced water before it is injected or otherwise disposed of

Liquid hydrocarbons removed from the production stream but not from oil refining

Gases removed from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons

Materials ejected from a producing well during blowdown

Waste crude oil from primary field operations and production

Light organics volatilized from exempt wastes in reserve pits or impoundments or production equipment

APPENDIX II

INFORMATION SOURCES FOR OKLAHOMA PETROLEUM E&P ENVIRONMENTAL SITE ASSESSMENT

Oklahoma Corporation Commission;

- Completion Report, Form 1002A
- Plugging Record, Form 1003/1003C
- Incident and Complaint Investigation Report, Form 1085
- Pollution Docket File and Orders
- OCC/OTC Operator Number
- Field Rule Orders
- Spacing and Pooling Orders
- Orphan Well List
- Commercial Mud Disposal Pit List
- Commercial Mud Disposal Annual Report, Form 1014A
- Commercial Class II Injection Well List
- Non-Commercial Class II Injection Well List
- Application For Class II Injection, Form 1015
- Annual Fluid Injection Report, Form 1012A
- Mechanical Integrity Pressure Tests, Form 1075
- Application For Permit To Use Earthen Pit, Form 1014
- Application For Land Application, Form 1014S
- Application For Waste Oil Or Drill Cuttings Use By County Commissioners Form 1014W
- Application For Waste Oil Or Drill Cuttings Use By Operators Form 1014X

APPENDIX II (Continued)

Commercial Industry Information Sources

- Oklahoma City Geological Society
- Completion Card, Oil Scout Card
- Herndon Map
- Other commercial maps; Petroleum Information, Geomap, Mid-Continent
- Sooner Well Log Records
- Production Information; Petroleum Information, Dwight's
- Oil Law Records
- Electric Logs; Riley's, Petroleum Information
- Petroleum Information On-Line service

Oklahoma Geological Survey

- Hydrologic Atlas
- USGS Topographic Maps
- Hydrologically Sensitive Area Maps (also OSDH)
- Regional Geologic Bulletins and Reports

Oklahoma Water Resources Board

- Well Head Protection Areas
- Water Well and Monitor Well Records
- Driller Licensing
- Laboratory Certification
- Boring and Monitor Well Regulations

Oklahoma Soil Conservation Service

- Soil Atlas
- Aerial Photographs

APPENDIX II (Continued)

County Records

- Ownership Records
- Property Tax Records

Operator Records

- OSHA Hazardous Communication Standard
- Spill Control And Countermeasure Plans
- NPDES Permit

Other Records

- Existing Environmental Assessments, Studies, Data
- Prior Use Records
- Fire Insurance Maps
- Local Street Directories
- Building Department Records
- Zoning/Land Use Records
- Historical Sources

APPENDIX III

GENERAL GUIDANCE FOR OILFIELD SAMPLING

(From multiple sources including the OCC 1993, Carl Solomon, Oklahoma State Laboratory, SW 846, RCRA TEGD, et al)

Use 1 liter plastic bottles with plastic lids for fluid samples to test for:

Total Dissolved Solids (TDS)

pH	Chlorides	Sodium	
Arsenic	Barium	Cadmium	Chromium
Lead	Mercury	Zinc	

If the sample is to analyzed for drinking water standards, collect 1/2 gallon in a clean plastic jug.

Use 1 liter wide-mouth glass jars and Bakelite lids with Teflon liners if sampling fluids for Hydrocarbon Scan (BTEX, TPH).

Use 1 liter glass jars and aluminum foil under the lids for hydrocarbons, oil, and grease samples. Preserve with 2 ml of sulfuric acid (H_2SO_4) and place in ice chest.

If soil samples are to be collected, use a 1 liter glass jar with a clean lid for:

pH	Chlorides	Total Soluble Salts	
Arsenic	Barium	Cadmium	Chromium
Lead	Mercury	Zinc	

Hydrocarbon Scan (BTEX, TPH)

APPENDIX IV

CLASSIFICATION OF WATER

After "Introduction to Water Resources and Domestic Water Supply in Oklahoma", by Wayne A. Pettyjohn and Hal White, OSU 1986.

Classification Of Saline Water

Classification	Dissolved Solids, in mg/l
Slightly saline	1000 - 3000
Moderately saline	3000 - 10,000
Very saline	10,000 - 35,000
Briny	More than 35,000

Classification Of Water Hardness

Concentration, mg/l	Description
0 - 60	soft
61 - 120	moderately hard
121 - 180	hard
more than 180	very hard

APPENDIX V

GROUNDWATER CONTAMINANT LIMIT GUIDANCE

	Action/ (SDWA/MCL) Cleanup I	Cleanup II	(Treatable) Cleanup III
Chloride	250 mg/l		5,000 mg/l
TDS	500 mg/l	5000 mg/l	10,000 mg/l
pH	6.5-8.5		
Sulfate	250 mg/l		
Zinc	5 mg/l		
Arsenic	.05 mg/l		
Barium	1.0 mg/l		
Cadmium	.01 mg/l		
Lead	.05 mg/l		
Mercury	.002 mg/l		
Chromium	.05 mg/l		
Benzene	.005 mg/l	.05 mg/l	.5 mg/l
Toluene	1.0 mg/l	10 mg/l	100 mg/l
Ethylbenzene	0.7 mg/l	7 mg/l	70 mg/l
Xylenes	10 mg/l	100 mg/l	1000 mg/l
TPH	2 mg/l	10 mg/l	25 mg/l

Concentrations Greater Than Site Background Levels

APPENDIX VI

SOIL CONTAMINANT LIMIT GUIDANCE

	Action/ Cleanup I	Cleanup II	Cleanup III
TSS	2500 mg/l	25000 mg/l	100,000 mg/l
SC	4,000 micromhos/cm		
pH	6.5-8.5		
ESP	15%		
Zinc*	5 mg/kg		
Arsenic	80 mg/kg		
Barium, ionic	4,000 mg/kg		
Cadmium	40 mg/kg		
Lead*	.05 mg/l		
Mercury*	.002 mg/l		
Chromium	40 mg/kg		
Benzene	.5 mg/l	5 mg/l	10 mg/l
Toluene	40 mg/l	400 mg/l	1000 mg/l
Ethylbenzene	15 mg/l	150 mg/l	1000 mg/l
Xylenes	200 mg/l	1000 mg/l	1000 mg/l
TPH	50 mg/l	500 mg/l	1000 mg/l

Concentrations Greater Than Site Background Levels

*SDWA MCL

VITA 2

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