BACKGROUND FOR NEPA REVIEWERS: CRUDE OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION

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DISCLAIMER AND ACKNOWLEDGEMENTS

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INTRODUCTION

The primary purpose of this document is to assist U.S. Environmental Protection Agency (EPA) staff in providing scoping comments and comments on National Environmental Policy Act (NEPA) documents for oil and gas exploration, development, and production activities proposed for Federal lands. Pursuant to NEPA and Section 309 of the Clean Air Act (CAA), EPA reviews and comments on proposed major Federal agency actions significantly affecting the environment. This document was developed to assist the EPA reviewer in considering those issues most appropriate to oil and gas operations in the development of NEPA/Section 309 comments. Ultimately, the document was also intended to assist operators in planning their work on Federal lands and to assist Federal land managers in the preparation of Environmental Impact Statements (EISs).

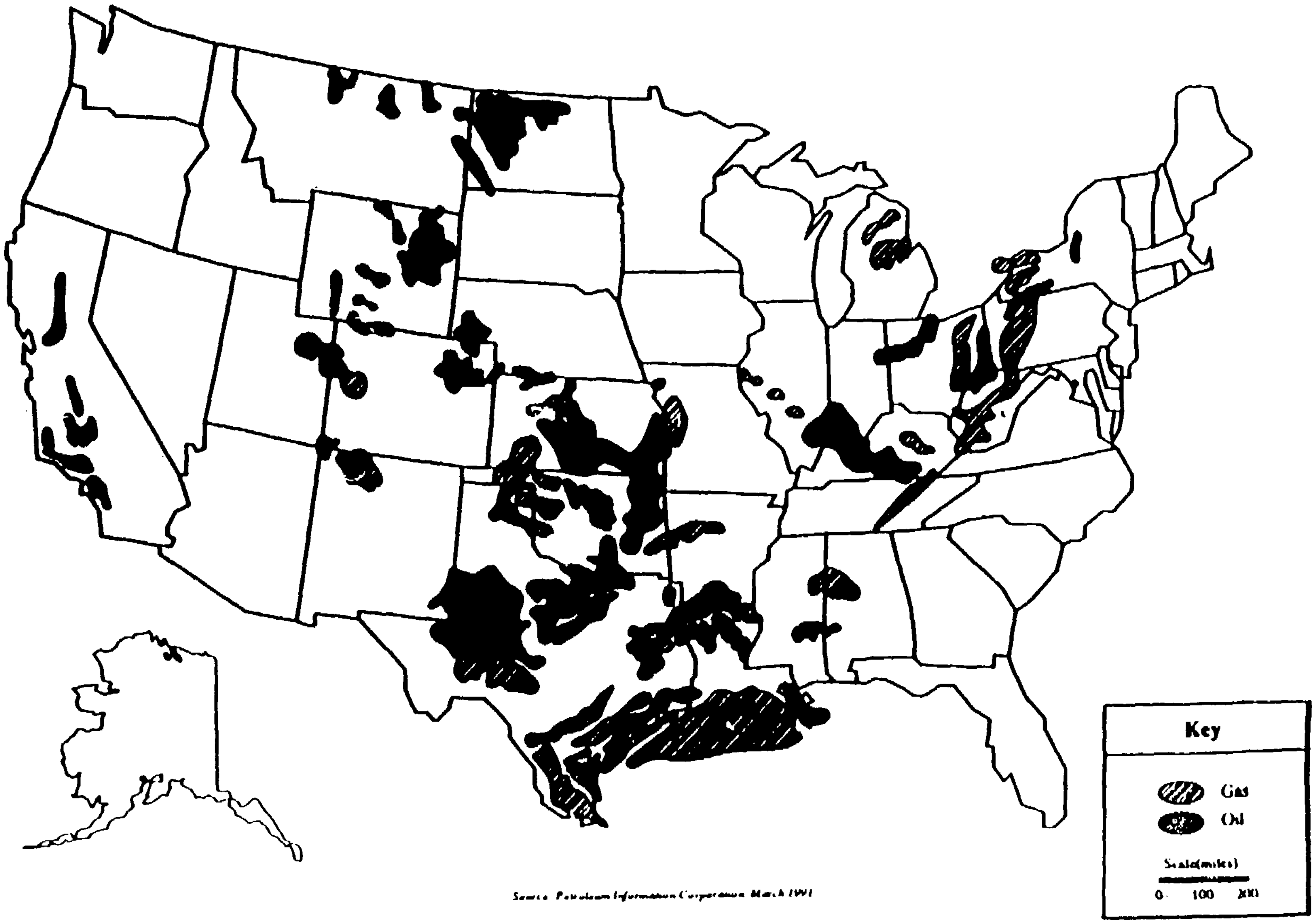
This document is not intended to be all-inclusive; rather, the document focuses on EPA's major concerns with surface and ground water, air, and ecosystems and sensitive receptors as related to oil and gas. It does not restate traditional NEPA concerns about impacts on floodplains, archaeological resources, etc., since they may occur at any development. Furthermore, it does not discuss (in detail) human health risks associated with oil and gas practices, since such risks are very site-specific. Finally, it addresses only onshore operations, and does not address offshore drilling and development.

The document is organized to provide a general description of site operations, potential environmental impacts associated with each operation, possible prevention/mitigation measures, and types of questions to be posed as part of the Agency's response. EPA recognizes that each oil and gas operation and each EIS is unique. Thus, reviewers may have to conduct additional analyses to fully understand projected impacts. The reviewer should not rely solely on this document as a definitive list of potential impacts or areas that should be covered by NEPA documentation. The particular operations that are stressed include areas that, overall, have significant impact on the environment. These operations include reserve pits, drilling fluids/cuttings management, produced water disposal, well site and road construction, product gathering systems (storage tanks and pipelines), and production operations.

OVERVIEW OF OIL AND GAS EXPLORATION AND PRODUCTION

Oil and gas exploration and production includes all activities related to the search for and extraction of liquid and gas petroleum from beneath the Earth's surface. Found almost exclusively in sedimentary rocks, oil and natural gas accumulate in geologic confinements called traps which, by virtue of an impermeable overlying layer, have stopped the migration of the fluid. The volume of petroleum contained in a trap can vary from negligible to billions of barrels. The major areas of onshore production in the United States include the southwest (including California), midwest and Alaska, with lessor contribution from the Appalachians. (See Figure 1.)
Though at one time such traps may have been close enough to the surface to allow easy detection (i.e., surface seepage), modern exploration relies on sophisticated geophysical testing techniques to

Figure 1. Location of Major Oil and Gas Production in the U.S.



locate potentially producible formations. Gravitational and seismic surveys of subsurface geology provide indirect indications of the likelihood of finding promising geological formations. This process is complicated by the fact that, at least in the U.S., the average depth at which one may reasonably expect to find oil is increasing since many of the largest shallow formations are assumed to have been found already.

If geophysical evidence suggests the possibility of finding oil is good, operators secure the required surface and mineral rights to the claim and prepare for drilling. If drilling is approved (by the appropriate land management agencies) an exploratory, or "wildcat" well is drilled. In spite of the high level of effort dedicated to locating potential oil reserves, only 1 in 7 wildcats finds hydrocarbons, and even less find enough oil under the right conditions to make production economically feasible. Typically, oil and gas are found commingled in the same reservoirs and are produced together. In addition, gas occurs in unique areas not associated with economic oil production. In these cases, natural gas may be produced and marketed without the product treatment facilities associated with oil production.

Changes in technology and increased demand for natural gas have spurred interest in an alternative natural gas resource, coalbed methane. Coalbed methane is found in underground coal seams sorbed (adsorbed or absorbed) to particle surfaces within the mineral. While all coal contains some methane, not all coal seams will exhibit economically producible quantities of gas. Estimated reserves of coalbed methane now approach the remaining proven reserves of conventional natural gas in the U.S. Major areas of production include the San Juan Basin of Colorado and New Mexico, and the Warrior and Appalachian Basins of the Eastern U.S. (Kuuskraa, V.A., and C.F. Brandenburg, October 9, 1989)

Modern well drilling involves the use of a rotary drill to bore through soil and rock to the desired well depth. The drill bit is constantly washed with a circulating drilling fluid, or "mud," which serves to cool and lubricate the bit and remove the cuttings to the surface. If the drill reaches the desired depth and fails to locate a producible deposit of oil or gas, the well must be plugged and the site abandoned. Even if oil and/or gas is found the well may not be producible. If the formation fails to exhibit the right combination of expected volume, porosity, and permeability, the costs of extraction would be prohibitive.

If an operator determines a well to be producible, the well must be completed and prepared for production. In instances where the reservoir is sufficiently large, "delineation" wells are drilled to determine the boundary of the reservoir and additional "development" wells are drilled to increase the rate of production from the "field." Because few new wells in the U.S. have sufficient energy (pressure) to force oil all the way to the surface, submersible pumps are placed in the wells and production begins.

This first phase of production, primary production, may continue for several to many years, requiring only routine maintenance to the wells as they channel oil to the surface for delivery to refineries. However, as the oil is removed from the formation the formation pressure decreases until the wells will no longer produce. Because 70 percent of the total recoverable oil may remain in the formation, additional energy may be supplied by the controlled injection of water from the surface into the formation. The injected water acts to push the oil toward the well bores. Such secondary recovery or "water flooding" projects may employ from a few to hundreds of injection wells throughout a field to extend the life of the wells. Much of the water used for injection is water pumped along with oil from the producing well, separated from the oil, and reinjected.

Often, service companies are hired by the oil company to perform many of the activities described above. Typically these contractors drill the wells and perform other specific tasks such as installing casing, conducting formation tests, and managing wastes, etc. (See Figure 2.) When a well or field ceases to produce oil or gas at an economically feasible rate, the field must be abandoned and reclaimed. Site closure includes the final disposal of the often considerable burden of wastes generated during the life of the project. Wastes generated during drilling and production include drilling fluids and cuttings and produced water.

The volume of drilling fluids and cuttings is in part a function of the depth of the well, which may range from 1,000 to over 10,000 feet. (The average depth of well drilled today is somewhat less than 5,000 feet with estimated drilling wastes at approximately 2 barrels per foot (bbl/ft). The largest of these wastes is formation water (called produced water), which is co-produced with oil in increasing amounts as the well ages. The average rate of water production for U.S. wells is approximately 10 bbl water/bbl oil although this varies significantly in different parts of the country. Additional wastes produced by oil and gas facilities include produced sand and pipe scale, wastes associated with well workovers and completions, cementing wastes, residual oils, machinery wastes, and chemical additives for a variety of uses. Wastes are sometimes disposed of in pits onsite. Produced water is often injected either for secondary oil recovery or as a disposal method. Additional waste disposal methods include land application, evaporation, or discharge to surface water.

A later section provides a detailed discussion of exploration and production operations as well as typical methods used for waste management throughout the lifetime of a project.

STATUTORY AND REGULATORY BACKGROUND

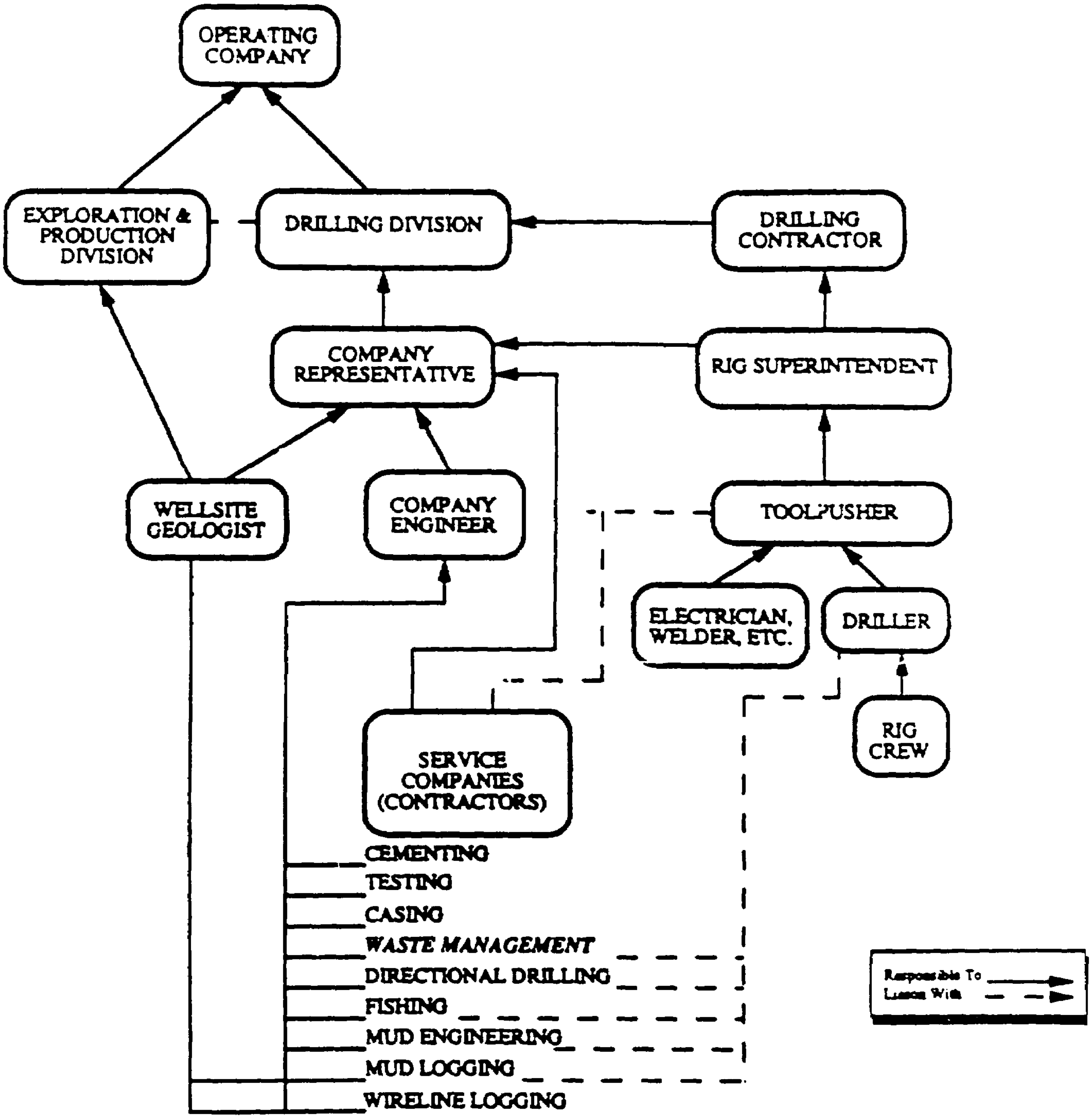
Oil and gas operations are addressed under several Federal statutes. As described below, the requirements of the National Environmental Policy Act are generally triggered during leasing actions on Federal lands. In addition, several Federal environmental statutes supply requirements intended to protect human health and the environment that are applicable to oil and gas operations. These include the Safe Drinking Water Act, the Clean Water Act, the Clean Air Act and the Resource Conservation and Recovery Act, which are discussed in more detail below. States may also have statutes and regulations applicable to oil and gas regulation, however these are not addressed in this report.

Leasing on Federal Lands

Oil and gas development on United States lands is conducted pursuant to a leasing system under which the lessee pays either a royalty on all oil and gas produced from the Federal land or a rental on those leased Federal lands that are not in production.

The Mineral Leasing Act of 1920 [30 United States Code (USC) Section 180, et seq., as amended and supplemented] is the law which provides the authority to lease oil and gas deposits on Federal lands. Under it, the Secretary of the Interior is responsible for issuing and managing Federal oil and gas

Figure 2. Interrelationship of Operator, Drilling Contractor, and Service Companies



(Adapted from Field Geologist's Training Guide, Exploration Logging, 1980) leases. However, the Secretary can lease oil and gas deposits on lands within the National Forest System only if the Secretary of Agriculture consents. Further, all surface operations under oil and gas leases on National Forest System lands are subject to the prior approval by the Secretary of Agriculture.

The Bureau of Land Management (BLM), the agency within the Department of the Interior which administers the leasing program, also generally requires the consent of any other agency responsible for managing a given Federal parcel (e.g., the Department of Defense or the Department of Energy) before it will issue a lease for the oil and gas deposits. However, the BLM will not necessarily require the consent of agencies other than the Department of Agriculture before approving specific surface operations once the lease has been issued.

The BLM regulations for administering the Federal oil and gas leasing program are found in 43 Code of Federal Regulations (CFR) Part 3100. For lands within the National Forest System, these regulations are supplemented by the United States Forest Service regulations in 36 CFR Parts 228 and 261.

Since passage of the Federal Oil and Gas Leasing Reform Act of 1987 (which amended the Mineral Leasing Act) most oil and gas leasing on Federal lands is conducted by competitive bid at oral auction under the regulations in 43 CFR Part 3110. Members of the public may nominate parcels for inclusion in a competitive lease sale, or the BLM may identify appropriate parcels on its own motion. Prior to actually offering lands for lease, the BLM must verify that they are legally eligible for leasing, (i.e., they are not closed to leasing by law), and that they are otherwise administratively available and appropriate for leasing. To do this, the BLM initially uses the Resource Management Plan to identify the general area to be leased. Resource Management Plans cover broad geographic areas, and are designed to provide general guidance on future uses of BLM-managed lands, including considerations of whether certain areas may be appropriate for oil and gas leasing. Under the BLM planning regulations in 43 CFR Parts 1600 and 1601, the BLM must conduct a full scale environmental analysis in accordance with NEPA prior to finalizing any Resource Management Plan.

Lands which are considered appropriate for leasing under a Resource Management Plan will further be reviewed by the BLM prior to being included in a lease sale. Traditionally, the BLM has not done a full-scale NEPA review for specific parcels prior to lease issuance, rather, it has delayed full-scale environmental review until a lessee requests permission to drill a well or initiate other surface-disturbing activities. See 43 CFR 3162.5-1. Some courts, however, have required the BLM to do a full-scale NEPA environmental impact statement prior to issuing specific leases unless the BLM reserves the absolute right (by appropriate stipulation in the lease) to prohibit any and all development under the lease at some later date if necessary to protect environmental values. Therefore, the BLM may conduct a full-scale NEPA review, either through an environmental assessment or an environmental impact statement, prior to lease issuance or only when the lessee seeks to begin surface-disturbing activity.

The Forest Service regulations for determining which National Forest System lands are available for lease are found in 36 CFR Part 228. Under Forest Service regulations, the Forest Service issues plans for management of all or part of a National Forest. As part of a Forest Plan, the Forest Service will decide which lands, if any, should remain open to oil and gas leasing. The Forest Service will conduct a full-scale NEPA analysis at the Forest Plan stage, and will also conduct a later NEPA analysis, if appropriate, when the BLM proposes specific parcels for inclusion in an oil and gas lease sale. Under its regulations, the Forest Service will consent to lease a given parcel only if it determines that the environmental effects of leasing have been adequately addressed, and that leasing is consistent with the applicable Forest Plan. The Forest Service, like the BLM, has authority to require that specific leases contain special stipulations to protect the environment. Lands offered for competitive sale which do not receive an adequate bid may then be offered for noncompetitive lease sale to the first qualified offeror. See 43 CFR Part 3110.

The BLM regulations in 43 CFR Part 3160 govern all aspects of production and development operations on the leased Federal lands (including drilling, road construction, waste disposal, reclamation, etc.). These regulations also govern operations on oil and gas leases on Indian lands, although Indian oil and gas leases are not issued by the BLM; they are issued by the Bureau of Indian Affairs within the Department of the Interior (under separate regulations). The Forest Service regulations in 36 CFR Part 228 establish the criteria for Forest Service approval or rejection of surface-use plans for operations on National Forest System lands.

Under the Oil and Gas Leasing Reform Act, the BLM and the Forest Service must require a bond adequate to ensure reclamation of leased areas. The BLM bonding regulations are found in 43 CFR Subpart 3104. They require submission of a surety or personal bond which will ensure compliance with the Mineral Leasing Act and regulations, including complete and timely plugging of wells, reclamation of the leased areas according to a plan approved by the BLM (or the Forest Service, for National Forest System lands) as required in 43 CFR Subpart 3161, and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of operations. For National Forest System lands, the Forest Service regulations in 36 CFR Part 228 provide that the Forest Service may require additional bonding if it finds the BLM bond is inadequate to reclaim and/or restore any lands or surface waters adversely affected by lease operations after cessation of operations on the leased property.

It is important to note that coalbed methane leasing is often complicated by uncertainty over the ownership of the resource. (Rocky Mountain Mineral Law Foundation, 1992) Historically, coalbed methane has had little or no economic value such that leases and even Federal statutes affecting rights to mineral resources on Federal lands have generally been silent with regard to coalbed methane. Emergence of commercial interest in the gas has spurred disputes between owners of surface, coal, and oil and gas rights, each claiming rights to the coalbed gas. Additionally, as development of the gas from a coal seam may damage the coal formation itself, conflicts may arise from concurrent plans to develop both coalbed gas and its source, coal. To date, no definitive answer to the question of ownership of coalbed gas has emerged.

Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) specifically addresses oil and gas operations under its Underground Injection Control (UIC) Program. This program is intended to protect usable groundwater from contamination by injected fluids. Underground injection wells used in the production of oil and gas are classified as Class II wells and are used to dispose of produced waters, to inject fluids for enhanced recovery, and to store hydrocarbons (that are liquid at standard temperature and pressure). Minimum requirements for UIC programs are established in 40 CFR

Parts 144, 145, and 146. State UIC programs must meet these minimum requirements in order to achieve primacy.

These minimum requirements stipulate that underground injection, except as permitted by the UIC program, is prohibited. In addition, the UIC program establishes specific construction, operation, and closure requirements, such as casing and cementing, plugging and abandonment, and monitoring of injected fluids and mechanical integrity of wells. Despite these measures, contamination of drinking water occurs via improperly plugged abandoned wells, casings, and through direct injection into aquifers. In 1989, EPA initiated evaluation of the UIC program. A Mid-course Evaluation workgroup convened to evaluate the effectiveness of the technical aspects of the UIC regulations. The workgroup recommended revision of the operating, monitoring, and construction requirements. In December 1990, EPA established a Federal Advisory Committee consisting of representatives from EPA, industry, the states, and environmental groups to implement the recommendations put forth by the Work Group. This committee is currently developing three guidances that are expected to be released in 1992: (1) Operating, Monitoring and Reporting for Class IID Commercial Salt Water Disposal Wells; (2) Management and Monitoring Requirements for Class II Wells in Temporary Abandoned Status; and (3) Follow-up to Class II Well Mechanical Integrity Failures.

Clean Water Act

Under the Clean Water Act, discharges to surface waters by oil and gas exploration and production activities are primarily addressed under the National Pollutant Discharge Elimination System (NPDES). EPA has promulgated national effluent guidelines for point source discharges from active oil and gas exploration and production operations in three categories: sites in territorial waters, on-shore, and coastal discharges. Coastal discharges are from operations located in waterbodies (or wetlands areas adjacent to waterbodies) that are inside the territorial waters. Coastal discharges are required to meet the technology-based effluent guidelines listed at 40 CFR §435.42. On-shore discharges, including potentially contaminated runoff, are prohibited, except for stripper oil wells (10 barrels per well per day) and discharges of produced water that are determined to be beneficial to agriculture or wildlife propagation (see 40 CFR §435.30). To date, the Agency has not promulgated discharge limitations for stripper wells. As a result, technology-based permit limitations for stripper wells are developed on a case-by-case basis or in a State-wide general permit. In all cases where discharges from oil and gas operations are allowed, NPDES permit writers must ensure that effluent limits provide for compliance with applicable water quality standards.

Under section 319 of the Clean Water Act, each State has been required to develop and implement programs that identify and regulate non-point source discharges from industrial facilities, including oil and gas exploration and production sites. EPA's role has generally been limited to reviewing State plans and providing program guidance. It should be noted that, under 19 amendments to the Coastal Zone Management Act, EPA is required to develop and publish guidance identifying "management measures" for sources of non-point pollution in coastal waters. These measures must reflect the greatest degree of pollutant reduction achievable through the application of the best available non-point pollution control practices, technologies, processes, siting criteria, operating methods, or other alternatives.

Under Section 402(p) of the Clean Water Act, EPA is required to issue NPDES permits for contaminated storm water discharges from oil and gas operations. Only oil and gas facilities that have had a discharge of storm water resulting in the discharge of a reportable quantity (as evidenced by a sheen) for which notification is or was required pursuant to 40 CFR 110.6, 117.21, or 3026 at any time since November 16, 1987, or contributes to a violation of a water quality standards are required to apply for a NPDES permit.

Finally, oil and gas exploration and production operations, which involve placing dredged or fill material in water in the United States (including many wetlands areas), must submit an application to the U.S. Army Corps of Engineers under Section 404 of the Clean Water Act. The Corps and EPA evaluate the Section 404 application according criteria developed by EPA to determine whether to allow the proposed action.

Clean Air Act (CAA)

Under the Clean Air Act (Section 109, 42 USC §7409), EPA established national primary and secondary air quality standards for six criteria pollutants. These National Ambient Air Quality Standards (NAAQS) set maximum acceptable concentration limits for specific airborne pollutants, including lead, nitrogen oxides, sulfur dioxide, carbon monoxide, ozone, and suspended particulate matter of less than 10 microns in diameter. State and local authorities were given the responsibility of bringing their regions into compliance with the NAAQSs. The primary vehicles for attainment are State Implementation Plans (SIPs). States were also given the authority to promulgate more stringent requirements.

The CAA also defines enforceable emission limitations for seven hazardous pollutants. National Emissions Standards for Hazardous Airborne Pollutants (NESHAPs) include benzene. However, none of these limitations applies to exploration and production. The 1990 amendments to CAA significantly expand the list of the specific pollutants for which national emissions standards must be determined.

New Source Performance Standards (NSPS), authorized by Section 111 of the CAA, set forth allowable emissions for new major sources and major modifications to existing sources. NSPS can extend to pollutants not included in the NAAQS and the NESHAPs. (Of particular interest to the exploration and production industry are volatile organic compounds (VOCs) and hydrogen sulfide.)

NSPSs have been promulgated for a number of source categories which may affect exploration and production operations. (See 40 CFR Part 60, et seq.) These include industrial steam generators, storage vessels for petroleum liquids, volatile organic liquid storage vessels (including petroleum liquid storage vessels), and gas processing plants (VOC's and SO_2). Specific NSPSs depend on whether the region has achieved compliance with the NAAQS and whether Non-Significant Deterioration (NSD) restrictions apply.

Under the 1990 amendments to CAA, Congress requires EPA to establish technology-based standards for a variety of hazardous air pollutants. EPA is required to publish a list of source categories by November 1991, present a schedule for setting standards by April 1992, and establish specific technology based standards for the selected sources between 1993 and the year 2000. Note that the list of categories may extend to exploration and production facilities such as flaring units and drilling fluid and cutting storage pits. Additionally, section 112(n)(5) of the Clean Air Act Amendments of

1990 requires the Administrator of EPA to conduct an assessment of the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natural gas resources and submit a report to Congress containing findings and recommendations within 24 months of the enactment of the Amendments. This section also authorizes the Administrator to develop and implement a control strategy under this section and section 111 for these emissions based on the findings of the study. Section 112(n)(4) contains certain constraints on categorization of oil and gas wells and pipeline facilities as major sources.

Resource Conservation and Recovery Act

Under Section 3001(b)(2)(A) of the 1980 Amendments to the Resource Conservation and Recovery Act (RCRA), Congress conditionally exempted several types of solid waste from regulation as hazardous wastes. Among the categories of waste exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas..." Section 8002(m) of the 1980 Amendments required EPA to study these wastes as well as existing State and Federal regulatory programs and submit a report to Congress. The Amendments also required EPA to determine whether the regulation of these wastes as hazardous wastes was warranted.

EPA determined the extent of the statutory exemption and thus, the scope of its Report to Congress on Oil and Gas Wastes, based on RCRA's statutory language and legislative history. EPA concluded that there are three criteria for determining whether a waste is exempt. First, the scope of the exemption covers wastes related to activities that locate, recover, and purify oil or gas, provided that the purification process is an integral part of primary field operations. Secondly, primary field operations include production-related activities, but do not encompass transportation or manufacturing activities (e.g., pigging wastes from transportation pipelines with respect to oil production; primary field operations encompass operations at or near the well head prior to transport to a refinery scope of the exemption). Finally, wastes must be intrinsic to and uniquely associated with these activities (e.g., wastes solvents from cleaning operations are not exempted) and must not result from transportation or manufacturing to maintain the exemption. With respect to gas production, wastes associated with production (including purification through a gas plant) but prior to transport of the gas to market, are excluded.

With EPA's 1987 "Report to Congress on Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy" and the July 1988 regulatory determination, the Agency completed these activities stating that regulation as hazardous wastes under Subtitle C was not warranted. Instead, wastes could be better controlled through State and Federal regulatory programs including Subtitle D of RCRA. Currently, EPA is in the early stages of developing a Federal Subtitle D program to address oil and gas wastes exempt from Subtitle C.

As stated in the July 6, 1988 Regulatory Determination (53 FR 25454), the Agency believes that produced water, drilling fluids and cuttings, and certain associated wastes should be exempt from Subtitle C. Examples of the exempted associated wastes include: well completion, treatment, and stimulation fluids; basic sediment and water and other tank bottoms from storage facilities that hold product or exempt waste; workover wastes; packing fluids; and constituents removed from produced water before it is injected or otherwise disposed of. However, the Agency believes that some associated wastes were not contained in the original exemption. These include: unused fracturing fluids or acids; gas plant cooling tower cleaning wastes; oil and gas service company wastes, such as empty drums, drum rinsate, vacuum truck rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids; and others, most of which are not uniquely associated with oil and gas activities. These wastes may be regulated under Subtitle C as hazardous wastes if they are listed or exhibit a characteristic (see 40 CFR 260-271).

Finally, the EPA has maintained that wastes from coalbed methane exploration and production are to be regulated the same as conventional oil and gas wastes. Accordingly, coalbed methane wastes are exempt from regulation under RCRA Subtitle C along with the analogous oil and gas exploration and production special wastes.

TECHNICAL DESCRIPTION OF EXPLORATION AND PRODUCTION OPERATIONS

EXPLORATION AND DEVELOPMENT

Exploration and development activities described below include well drilling, completion, stimulation, abandonment, and waste management. Production operations, which begin after well completion (and, if necessary, stimulation), include primary and secondary recovery, product collection, produced fluid treatment, and waste management. Exploration and production operations and major activities that may occur during each, are described in the following subsections.

Road Construction and Maintenance

Initial land disturbance associated with oil and gas operations usually occurs when roads are constructed to access areas for exploration, drilling and development. In some exploration off-road vehicles may be used, avoiding the necessity of road building; however, to move many drill rigs and other equipment to drill sites, graded roads are constructed and maintained. In constructing roads, grading, installing culverts, and building berms may affect surface drainage patterns. In an effort to control dust, roads are often sprayed with water or other liquids on a regular basis.

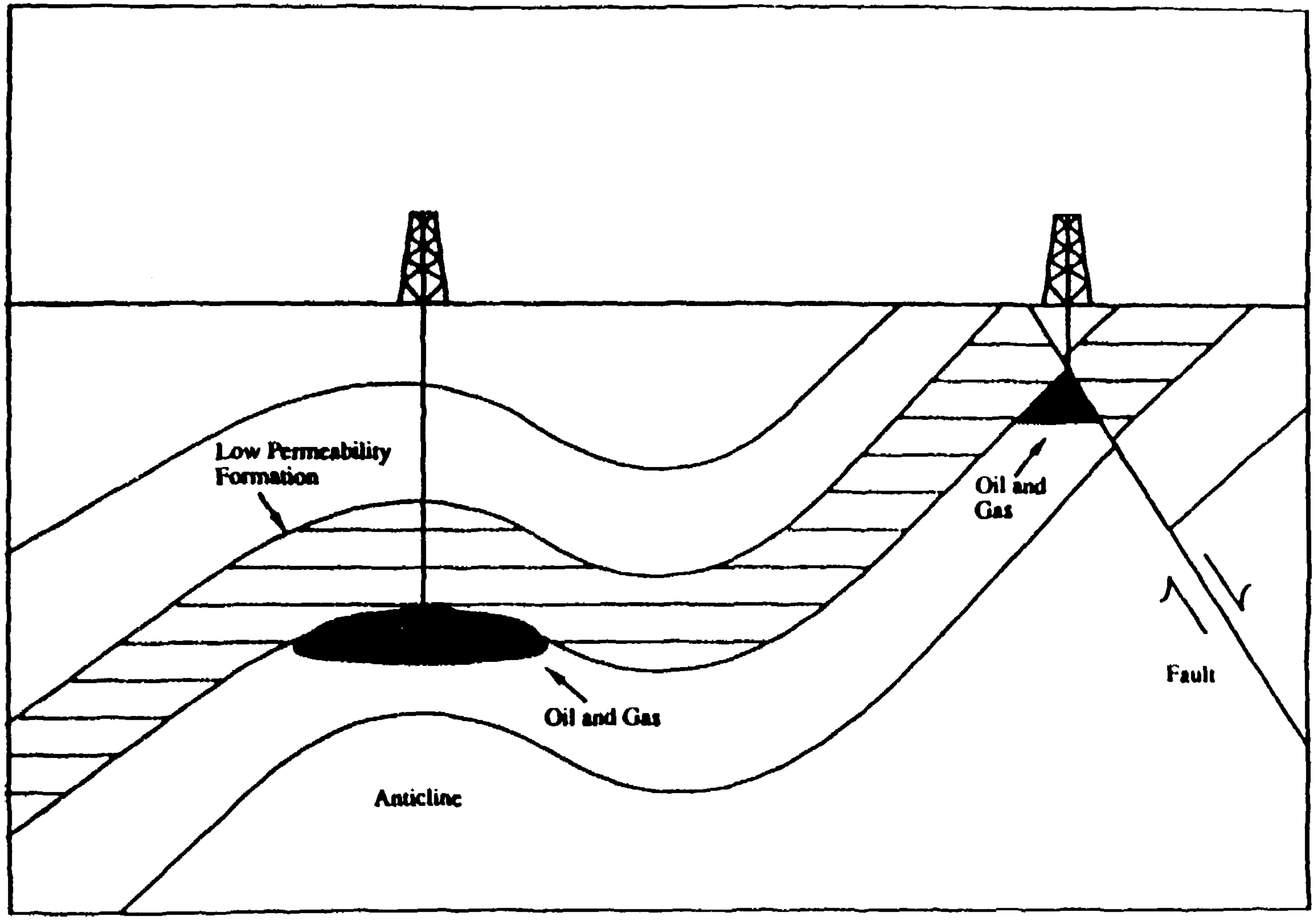
Preliminary Exploration

Based on initial geologic research, areas that have promising geologic structure and composition are identified. Geophysical exploration or prospecting is then conducted, typically using seismic surveys to delineate the subsurface structure and identify potential traps where hydrocarbons may have accumulated. (See Figure 3.)

Seismic surveys delineate stratigraphy by measuring the speed of shock waves as they propagate through the subsurface, reflecting, refracting (bending) and traveling at different speeds through different rock types. Generally, the shock is caused by a charge set below the surface (usually a 50 pound charge at a depth of 100 - 200 feet) or slightly above the surface (2.5 to 5 pound charge). In some cases, a thumper truck may be used in place of a charge. As the shock waves travel, a sensor called a geophone, located a set distance from the shock initiation point, detects the shock waves as they surface. The shock waves, after they are reflected or refracted, appear at the surface as a portion of their initial energy and are correlated with the time and distance traveled to delineate subsurface structures. Typically, seismic surveys are conducted along transects with repeated trips along the survey line necessary to maintain lines and equipment. This may in turn require road construction or at a minimum create 4-wheel drive trails along each transect.

A less popular method of collecting geophysical information is through gravity surveys which detect small variations in gravitational attraction that correspond to differences in the density of various rock types.

Figure 3. Typical Oil and Gas Structural Traps



Seismic surveys or other indirect prospecting can be confirmed with direct explorations such as mapping of rock outcrops and oil seeps and review of drill cores. All available information is used in determining whether to drill a well and in selecting the well site.

Well Drilling

A well site is selected on the basis of seismic and gravity surveys, known geologic data, topography, accessibility, and lease requirements. Typically, a drilling contractor is hired to do the actual field work with supervision by the operator's geologist and drilling engineer. In addition to drilling, which is generally contracted to an outside firm, other outside contractors provide services such as well logging, mud engineering, and well stimulation.

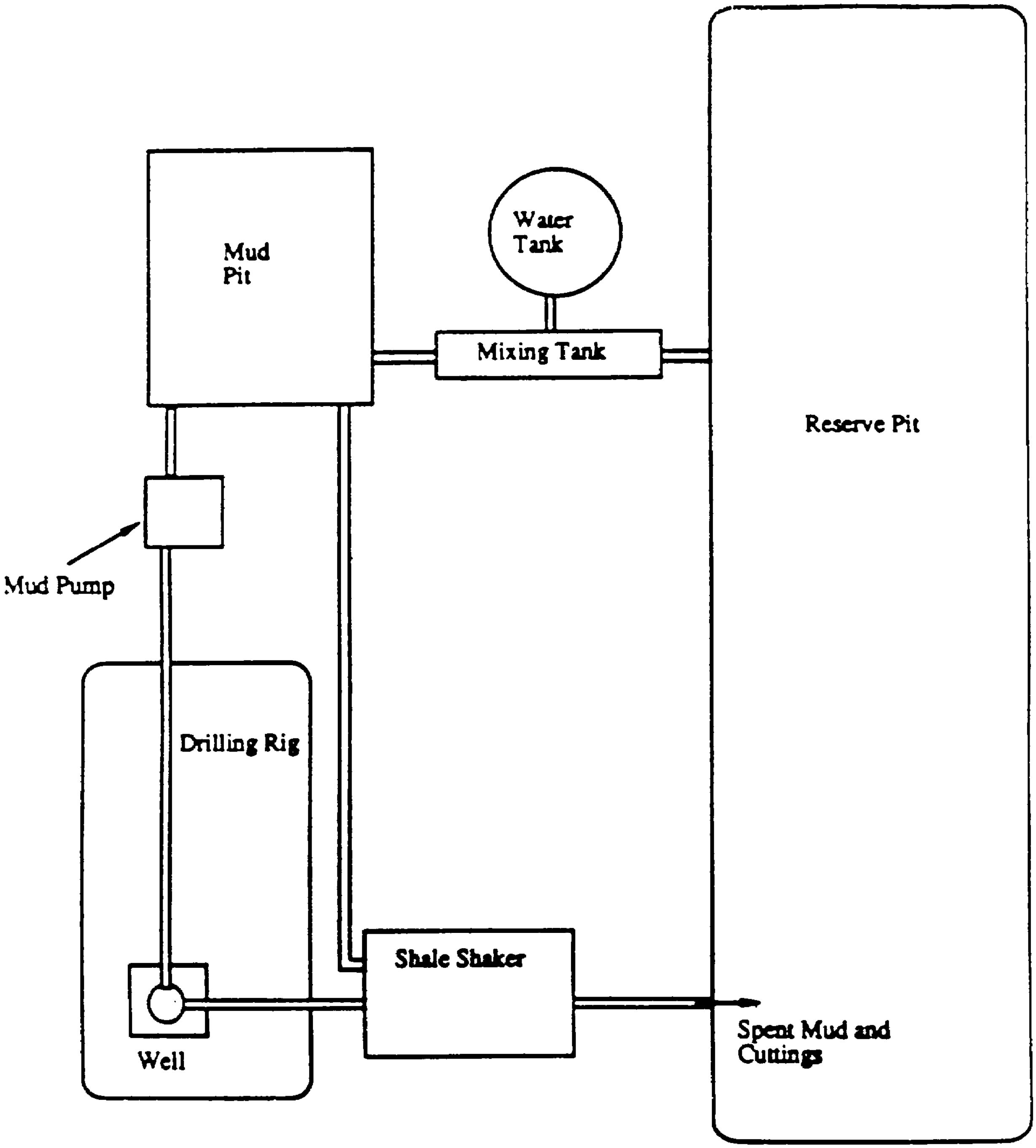
Drilling operations require construction of access roads, drill pads, mud pits, and possibly work camps or temporary trailers. Typically, drilling operations continue 24 hours a day, 7 days a week. A portable lab trailer is onsite to determine initial oil and gas shows (traces of oil and gas) from cuttings (pieces of rock cut from the formation at depth) obtained at the depths of interest.

After the well site is selected, the drill pad is prepared. Drill pads generally range from 2 to 5 acres; they are level areas used to stage the drilling operation. Usually, the pad accommodates the rig and associated facilities (i.e., pumps, mud tanks, the reserve pit, generators, pipe racks, etc.). (See Figure 4.) The most commonly used rig is the rotary drilling rig, which is usually powered by a diesel engine. The rig employs a hoist system (which consists of a derrick, crown block, and traveling block) to lift and lower the drill. The drill bit is fastened to (and rotated by) a hollow drill string, with new sections or joints being added as drilling progresses. The cuttings are lifted from the hole by drilling fluid, which is continuously circulated down the inside of the drill string through nozzles in the bit, and upward in the annular space between the drill pipe and the borehole or casing. The drilling fluid or mud lubricates and cools the bit, maintains downhole pressure control, and helps bring the cuttings to the surface. (See Figure 5.)

At the surface, the returning fluid (mud) is typically diverted through a series of tanks or pits, where the cuttings separate from the mud. In many cases, cuttings shale shakers, desanders, and desilters are also used to aid in separating cuttings from fluid. The waste sand and silt removed from the mud is typically disposed of in a reserve pit. After the cuttings are removed, the mud is picked up by the pump suction, and the cycle is repeated. Drill cuttings are one of the largest wastes associated with drilling. Mostly rock, the cuttings discharged to the reserve pit may contain up to 10% adhered drilling fluid solids. As a result, potential pollutants generally mimic those of the drilling fluids used, as discussed in the next section.

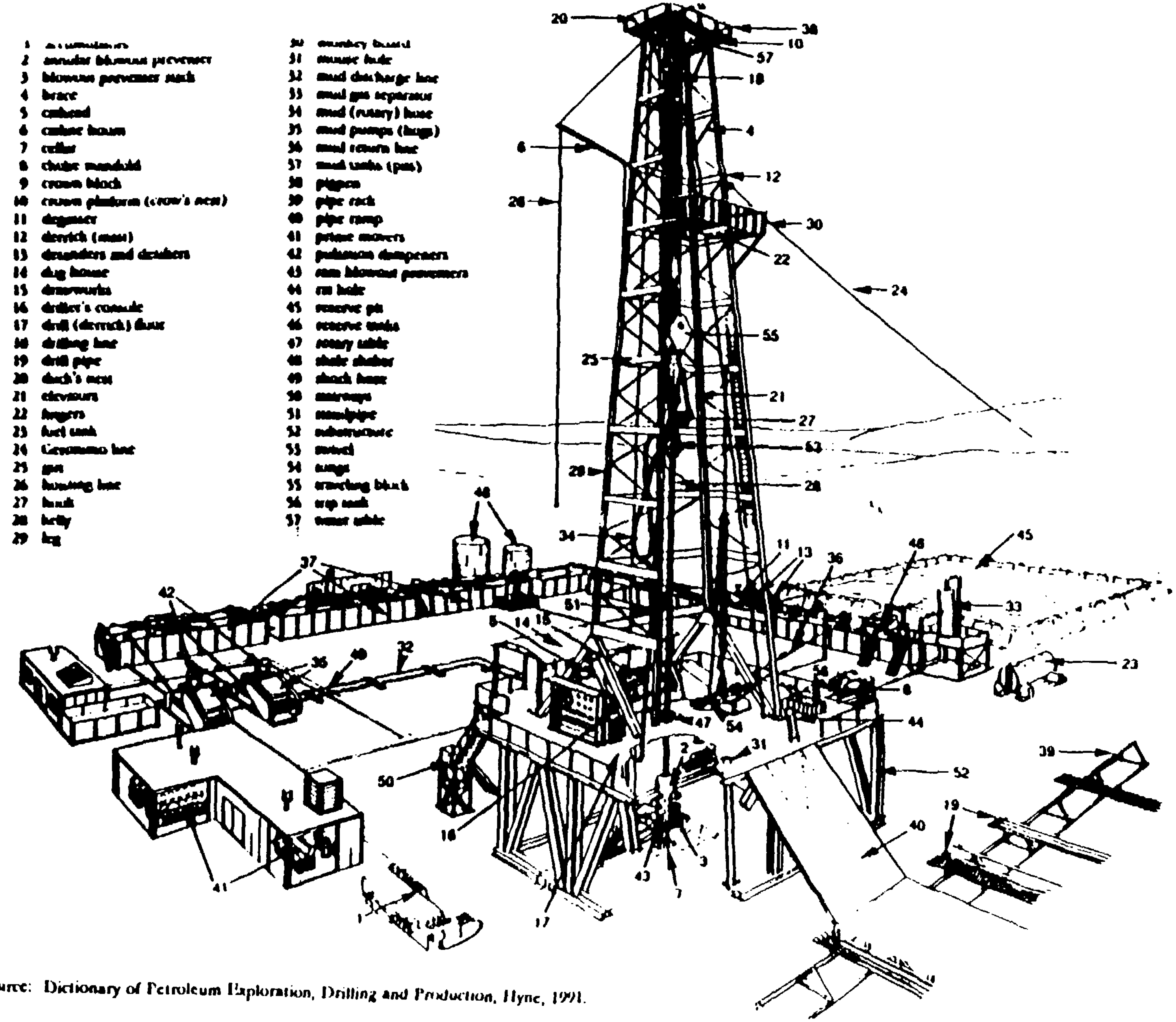
The initial hole is drilled to a depth of about 100 feet, and a conductor pipe or casing is cemented in. The required depth of the conductor pipe is a function of the potential for washout of the hole while drilling to surface casing depth (see below), formation pressure, and the location of any USDWs. The pipe must be set in rock that is strong enough to handle the maximum anticipated pressure. A series of Blowout Preventer (BOP) valves are attached to the well. A blowout occurs when formation pressure exceeds the mud column pressure, which allows the formation fluids to blow out of the hole. This is a costly, highly feared hazard of drilling. Proper mud design is essential to prevent this problem.

Figure 4. Aerial View of a Typical Well Site



After: Welker, A.S. The Oil and Gas Book. 1985

Figure 5. Rotary Drilling Rig



Source: Dictionary of Petroleum Exploration, Drilling and Production, Hyne, 1991.

Drilling is resumed after the installation of casing and BOP valves, using a smaller bit. When the drilling depth reaches several hundred feet, the drill string and the bit are pulled out of the hole and surface casing is lowered into the hole and cemented in. (The depth of surface casing depends on the location of USDWs, formation pressures, and the tendency of the bore to slough.) This operation prevents any sloughing of the surface formation into the hole; it is also intended to protect any aquifers from being contaminated. If deeper fresh-water aquifers are present, cement can be squeezed through tubing to plug off the fresh-water zones and prevent dilution of the mud column (and possibly intrusion of contaminants into the freshwater zone). This prevents alteration of the mud density and the swelling of clays encountered in some formations.

During the drilling process, the drilling string is pulled from the hole periodically to change the bit, install casing, and/or remove core samples from the well bore. As explained previously, first the conductor pipe is installed to a depth of approximately 100 feet and BOP valves are installed. Then, when drilling reaches below the fresh-water zones or aquifers, the surface casing is installed. In exploratory wells, after the surface casing is set, the well is drilled to its final depth prior to installing the final casing. Because well casing is costly, deeper casing strings will not be installed until the production potential of the well is determined. Conversely, development well casing may be set as the well is drilled to prevent caving of the bore. In these wells, as the drilling proceeds, additional casings of smaller diameter are lowered into the well and cemented in. Usually, 90-foot joints made of three 30-foot sections are successively lowered into the hole until they reach the final depth. As casing is set, waste drilling muds and cement returns are circulated to the surface. The setting of casing and preparation of the well for production is called completion and is described in further detail in a following section.

Drilling Fluids

Although drilling can be conducted without using fluids (muds), most drilling requires a fluid mud to cool the bit and control downhole pressure. In soft-rock areas, successful completion of a well may require very precise control of mud properties. In hard-rock areas, water may be satisfactory and is sometimes even a superior drilling fluid. In addition to liquid muds, both air and gas are used as drilling fluids in many areas. Therefore, the selection of mud type is governed by the specific requirement of the geologic area. It also depends on the drilling fluid's ability to cool and lubricate the bit and drilling string; remove and transport cuttings from the bottom of the hole to the surface; suspend cuttings during times when circulation is stopped; control encountered subsurface pressures; and wall the hole with a low-permeability filter cake in poorly consolidated formations.

A typical mud consists of a continuous phase (liquid phase), a dispersed gel-forming phase such as colloidal solids and/or emulsified liquids, which furnish the desired viscosity, and wall cake. Muds may be either water- or oil-based with other dispersed solids such as weighting materials and various chemicals added to control the mud properties.

A water-based mud may consist of either fresh-water or salt-water mud. Fresh-water mud can simply be a clay-water mixture, a chemically treated clay-water mixture, or calcium-treated muds. In a salt-water mud, the clay mineral (attapulgite) hydrates and forms a stable suspension in salt water. Such clays are commonly called salt-clays and are used in saline water in about the same manner as bentonite is used in fresh water. In general, the difference between fresh- and salt-water muds is the type of clay used as the gel-forming phase.

Oil-based muds are expensive and are used as a special-purpose drilling fluid. They are insensitive to common contaminants such as salt, gypsum, and anhydrite, since these compounds are insoluble in oil. The principal use of the oil-based muds are:

- Drilling and coring of possible production zones to determine the water content, permeability, and porosity of the formation
- Drilling of bentonitic (heaving) shales that continually hydrate, swell, and slough into the hole when contacted with water
- High-temperature drilling, where possible solidification or other problems make other muds undesirable
- As a perforating fluid (normally, a few barrels spotted opposite the zone to be perforated will prevent contamination of the section after it is perforated) (See below for description of perforation)
- Freeing of stuck pipe, lubricity control, corrosion prevention, and remedial work on producing wells.

The alteration of mud density may prevent problems due to lost mud circulation. This approach includes the use of air and natural gas as drilling fluids. The main benefit of using such practices is the economy from a large increase in penetration rate. However, there are hazards involved (i.e., explosions and fires); and extra safety precautions are necessary.

Drilling Fluid Wastes

Because of the wide range of mud designs in use, the potential contaminants to be found in used drilling fluids varies substantially from site to site. Further, since used muds are stored in the reserve pit, they may be exposed to other contaminants from the operation.

Chlorides from downhole brines, salt domes, or salt water based muds can be found in high concentrations. Muds in the reserve pit may have chloride concentrations of 1.5 to 30.0 ppt (EPA, 1987). Barium, from barite used as a weighting agent, may reach 400,000 mg/l in muds used for deeper wells (Neff; EPA). Because of contact with petroleum bearing formations (as well as the use of petroleum as an additive), used drilling fluids may contain a number of organic compounds of potential concern. These include naphthalene, toluene, ethyl benzene, phenol, benzene, and phenanthrene. Finally, used drilling fluids may contain a number of inorganic compounds, either from additives or from downhole exposure. Such substances include arsenic, chromium, lead, aluminum, sulfur, and various sulfates.

Formation Evaluation

Formation evaluation methods such as well logging and drill stem testing are means of determining whether or not a well can be completed for commercial production. These methods are also useful in defining individual characteristics of the pay zone, which dictate the completion method. Well logging consists of graphical portrayal of drilling conditions or subsurface features encountered that relate to the progress or evaluation of potential zones. Wireline logs are specific types of well logs that are generated by lowering sensors down the well on a wireline. These sensors remotely measure electric, acoustic, and/or radioactive properties of the rocks and their fluids. Drill-stem testing uses the temporary isolation of a prospective formation (from other formations that have been penetrated) by means of relieving the mud pressure so the fluids can flow into the drill stem. Coring consists of cutting and retrieving a relatively large, intact chunk of the formation rock to determine porosity, permeability, and fluid content.

If an exploratory well is successful and has sufficient reserves to be economically developed, the well is completed (see next section), and depending on the reserves characteristics, an oil field may be developed by installing more wells. However, if the exploratory well does not show signs of potential economic production, the well is plugged and abandoned (see section on abandonment).

Well Completion

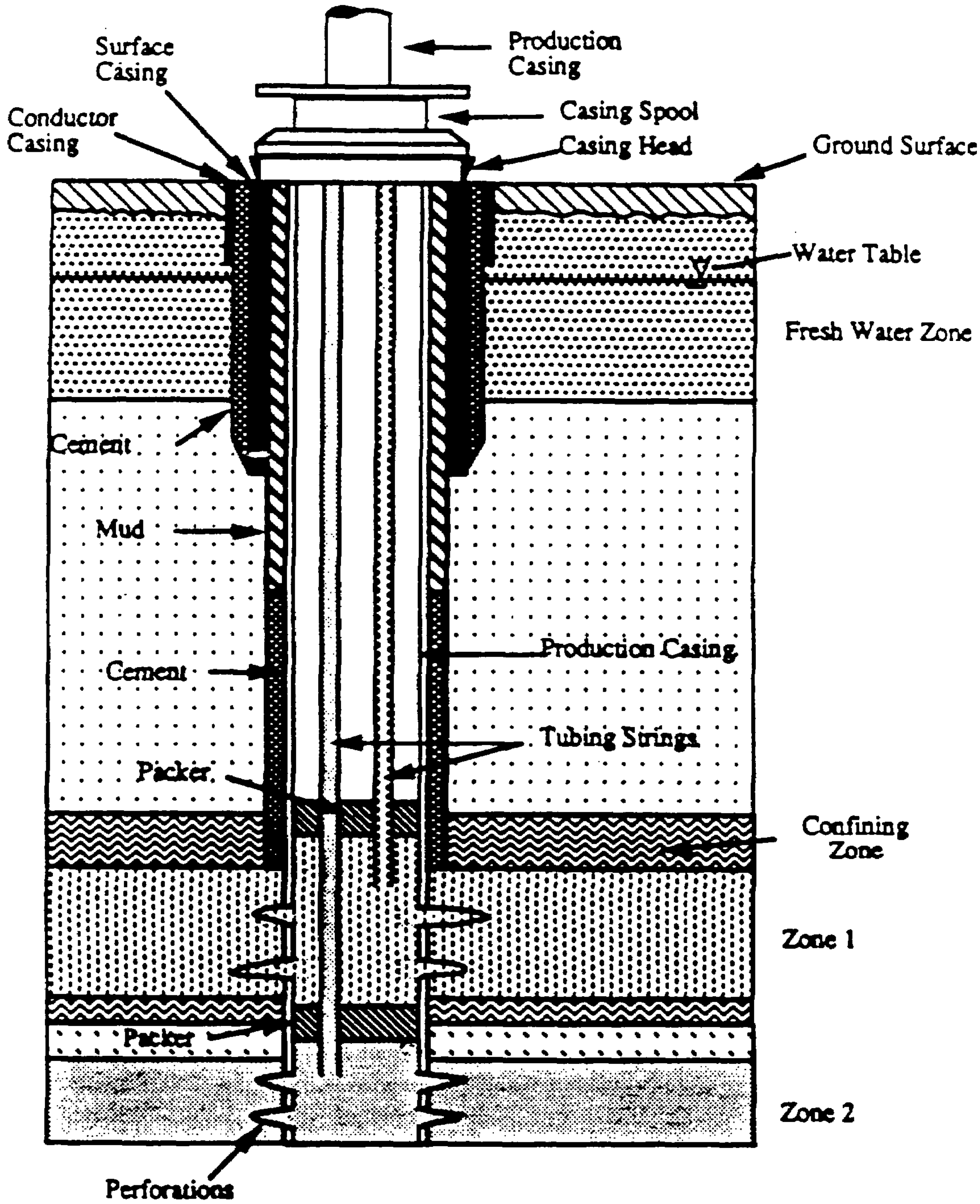
After reaching the desired depth and determining that the well has tapped sufficient reserves to be economically developed, the well is completed. Cased holes are the most common type of well completion. First, casing strings are cemented in the hole (casing strings are joints of casing, and each joint is approximately 30 feet long). Then production tubing strings are set inside the casing (tubing strings are joints of tubing or piping through which the hydrocarbons flow; each joint is about 30 to 32 feet long). Packers (removable plugs) are set to separate producing zones (if desired).

Before the tubing strings are set, to let the pay-zone fluids enter the cemented casing strings, operators use perforating guns to perforate the casing down hole. A perforating gun is lowered into the hole on a conductor cable (a cable that transmits electrical signals) by wireline until it reaches the depth of the pay zone or zone to be perforated. The perforating gun is then fired, penetrating the casing with bullets fired from the gun and creating channels from the formation to the well bore. At this time, the pressure exerted by the fluid within the casing typically exceeds the formation pressure so no formation fluids can enter the casing. To allow formation fluids to enter the well, fluid inside the well bore (brine solution with chemical additives to control flow from the formation) is swabbed by a cylindrical rubber cup on a cable through the tubing strings. This waste (brine and chemical additives) is usually discharged to the reserve pit.

A well may be completed with single completion (completed in one formation); multiple completion (completed in separate formations at the same time with separate production equipment for each formation); or commingled completion (completed in more than one formation at the same time using a common production system). (See Figure 6.)

In some parts of the country, formation sands affect production by interfering with surface production equipment. This occurs most often in West Coast and Gulf Coast areas that produce from zones

Figure 6. Cross Section of a Well with Multiple Completion



where the sand grains have poor cohesive properties. The sand is produced with the oil and water, causing problems in the treating and separating process (e.g., sand grains destroy production equipment). Downhole installation of a gravel-packed liner helps reduce the sand entry into the production line. The gravel-packed liner is made from production casing with small screens instead of holes or slots. The space between the screen and the sides of the borehole is filled with coarse sand, which helps filter out the formation sand.

Completion Wastes

Wastes from well completion include fluids placed in the well to control pressure. These fluids may be water with or without additives (salts, organic polymers, or corrosion inhibitors) used to control density, viscosity, and filtration rates; prevent gelling of the fluid; and reduce corrosion. Generally discharged to the reserve pit or a dedicated completion pit, completion wastes also include waste cement, residual oil, paraffins, and other materials cleaned out of the bore.

Well Stimulation

In some cases, after a well is completed, the formation does not show a promising amount of petroleum products as indicated on a well log or core samples. The porosity or permeability of the zones may be too low for the flow to take place, or the drilling mud may have damaged the formation by plugging up the pores and reducing the permeability near the well bore. Operators use a variety of well-stimulation techniques to correct these problems during the exploratory and development phases of the well. Usually well-stimulation activities are contracted out to service companies. Well stimulation is often conducted initially when the well is completed, and may be conducted on a routine basis throughout the operating life of the well to maintain the flow rate. Stimulation conducted on an actively producing well is often referred to as a "workover."

The two most often used techniques for stimulating a well are acidizing and fracturing. Acidizing increases the permeability of the formation in the area near the well bore and increases local pore size. Acidizing dissolves waxes, carbonates, and other materials clogging the area near the bore. After the acid treatment, the "spent" acid is allowed to flow back. If the well will not flow, it is swabbed to draw liquids out (by means of a rubber cup lowered into a well by a cable). Today, acidizing is applied primarily to carbonate (limestone and dolomite) rock. Hydrochloric acid (HCl) is by far the most common acid because it is economical and leaves no insoluble reaction product. Other acids used are formic acid, acetic acid, and hydrofluoric acid, and mixtures of these acids.

Acidizing is a localized stimulation method. Depending on the formation, type of acid used, volume of acid used, and pump rate, the extent of stimulation varies. Usually between 200 and 2,000 gallons, the spent acid is usually trucked away for disposal at proper facilities by the service company providing the work. The swabbed fluid from the well bore is usually brine, and is handled like produced water.

Another method used to stimulate a well is hydraulic fracturing. Hydraulic fracturing involves pumping a fluid (acid, oil, water, or foam) into the formation at a rate that is faster than the existing formation pore space can accept. The formation will crack due to the high pressure induced by the fracturing process. A proppant material such as sand, glass beads, or ground walnut shells is pumped with the treating fluid to prevent the fracture rrom closing (i.e., they prop open the fractures).

After the desired stimulation technique has been applied, the well is retested for flow rate. If the results are poor, the well is plugged. If the formation shows improvement and it becomes economic to operate, production equipment will be installed to lift the petroleum to the surface where it can be treated to remove impurities and marketed.

Stimulation Wastes

Wastes generated from stimulation are spent fluids including weighting agents, surfactants, muds, produced water, acids, inhibitors, gels, solvents, and other materials. These fluids are generally produced with petroleum as formation pressure forces the fluids back to the well bore. As a result, much of the material is removed from the production stream at the production treatment facilities described later. Initial returns may be discharged to the reserve pit or a dedicated workover pit. Alternatively, some of the fluids may be removed by vacuum truck to offsite disposal facilities.

Well Abandonment

As discussed above, if a wildcat well is not a success, it is plugged and abandoned. In addition, production wells may be plugged or abandoned if the lease is no longer economically feasible, and facilities may be removed to other leased properties where they can be utilized more efficiently.

For wildcat wells that are not successful, the procedure used to plug a drilled hole varies, depending on hole conditions and regulatory requirements. The objective in plugging a hole is to prevent cross flow between major geological formations. A cement slurry, circulated in place with the drill string, is often used to plug dry holes. In some cases, rather than fill the entire hole with cement, operators may plug only those particular formations that regulatory agencies specify must be isolated. The remainder of the borehole space between the cement plugs is then filled with muds chemically treated to degrade more slowly than typical drilling mud.

In cases of production wells that are no longer economical, tubing and liners are pulled out of the well after the well-head assembly is removed. Cement plugs may be installed above and below the fresh-water aquifers, and across all perforated zones (extending some distance above and below the area). A cement mixture or sometimes an upgraded mud mixture is circulated downhole to balance the back pressure or formation pressure. Casing is cut and pulled from about 100 to 200 feet from the surface or ground level depending on local requirements. A final cement plug is set all the way to the surface and, finally, a concrete slab is placed on top of the cement plug at ground level.

Abandonment Wastes

Well abandonment generally includes site closure. Wastes such as residual muds and excess cement may be added to the reserve pit prior to final pit closure. Pit closure is discussed later under Waste Management.

OIL AND GAS PRODUCTION

Field Design

Once a reservoir is determined to be economically producible, field design is required. The wildcat well provides information such as depth of producing zones, water cut, oil and gas quality, and reservoir properties. Additional holes called delineation wells are drilled to determine reservoir boundaries. Depending on the data provided, a recovery method is selected and well spacing and pattern is mapped out to achieve optimum recovery of the petroleum, while also complying with State requirements for well spacing. The network of wells is designed to drain the reservoir while preserving as much downhole pressure as possible. Factors involved include viscosity of the oil and the geological structure and natural flow conditions of the reservoir.

Dedicated gas field development may proceed based on different factors. Because gas produces (rises to the surface) on its own, a field will not be developed until a buyer for the gas is secured. Thus, the number and spacing of the wells must in part be based upon contracted delivery rate in addition to the physical characteristics of the reservoir.

Recovery

After wells are drilled and completed, they are ready to be produced. There are several types of recovery methods in production operations. The first is primary recovery, which uses natural flow and artificial lift to get the hydrocarbons to the surface. Artificial lift may consist of submersible pumping units to pump the hydrocarbons to the surface or gas lift where gas is injected into the tubing/casing annular space of a well. In gas-lift situations, special valves in the tubing allow the gas to enter the tubing at selected depths and mix with the produced fluid in the tubing. This lightens the weight of the produced fluid and helps the well flow by using the available reservoir pressure.

Most fields initially produce by primary recovery methods, but the natural decline rate of wells generally indicates when workovers or other methods of recovery are needed to maintain or improve production.

Secondary recovery methods are used when the natural energy of the reservoir has been depleted and primary production is no longer efficient. Methods include waterflooding or gas injection into the reservoir to maintain pressure. In waterflooding, the produced water may be treated to meet guidelines (set up by the local agencies) for injection. A pattern of injection wells and production wells are mapped out to achieve maximum sweep efficiency (all the producers are receiving their required amount of pressure maintenance). The source of water can be produced water or water from a nearby lake. Gas injection or immiscible-gas injection involves injecting a gaseous substance that will not mix with oil into the reservoir. The process is similar to waterflooding except that it uses methane, ethane, or nitrogen gas as an injection fluid.

Tertiary recovery refers to the recovery of the last portion of economically recoverable oil (by manipulating characteristics of the oil as well as the reservoir). Generally, tertiary recovery involves the injection of a fluid other than water to increase pore pressure of the formation and help thicker or heavier hydrocarbons to flow. Steam injection, and in some rare cases microbial treatment (use of bacteria that break long-chain hydrocarbons) or insitu-combustion may also be used for tertiary recovery.

Miscible injection, a method of tertiary recovery, involves injecting a fluid that will readily mix with the oil in a reservoir. The injection fluid may be alcohol, refined hydrocarbons, propane, butane, or carbon dioxide. Polymer flooding involves injection of polymers (long-chained molecules that thicken water) such as polysaccharides and polyacrylamides. Once the water is thickened, the process continues like a waterflood project. Due to the high cost of the polymers, this method is restricted to thick oil reservoirs that do not respond well to waterflooding.

In steamflooding (like waterflooding) both injection and production wells are used. Water is heated within surface steam generators until it changes to steam. The steam is then injected into the reservoir through injection wells. This method is used for heavy oil (thicker than the polymer-flooding reservoirs), and often a portion of the produced crude oil is used as fuel to run the generators.

Cyclic steam (push-and-pull or "huff and puff") injection uses the production wells for injection. A single well bore serves as a temporary steam injection well. Then, it is converted for use as a temporary producing well. The well may be shut in for a few days so that the energy stored in the reservoir is not depleted too quickly. This injection/production cycle is repeated until the economic limit is reached.

In-situ (in place) combustion (burning) involves burning the oil while it is still within the reservoir pore space. The combination of oxygen (supplied by injected air from an injection well) and fuel (supplied by the reservoir oil) creates a flammable mixture that will burn until the supply of oxygen or fuel is exhausted. The burning of a small portion of the underground oil increases the formation pressure pushing the remaining unburned oil toward the production well. This is not a very popular method of recovery because of high operating costs and massive operational problems (i.e., melted casings); it is uneconomic in most instances. Both secondary and tertiary recovery are often referred to as "enhanced" oil recovery.

Stripper wells constitute a special case of recovery methods, usually near the end of the life of a well. Stripper wells are defined as wells that produce less than ten barrels of oil per day. Relative to nonstripper wells, the water cut for strippers may be high, well over 10 barrels of water for each barrel of oil recovered. Marginally economical to produce, most stripper operations are very sensitive to the price of oil. As a result, they are candidates for various regulatory exemptions regarding waste management. Generally owned and operated by independent companies, the nature of surface treatment facilities may differ from larger operations. Note that stripper wells account for nearly 75 percent of all United States producing wells and produced 15 percent of United States domestic oil in 1989.

Product Collection (Gathering)

As oil and gas is recovered from wells, it is collected or gathered in pipelines for transport to produced fluid treatment facilities (discussed in the next section). Generally, gathering lines (flow lines) are routed from the wellhead to the treatment units and on to storage. The flow lines may be above or below ground. If below ground, they may be equipped with leak-detection systems to prevent damage to the environment and loss of product.

Occasionally, gathering lines may become clogged with the build-up of paraffins and pipe scale (carbonates and other materials on the pipe wall). In such cases, pipeline "pigs" or heated oil are used to remove the blockage. Pigs are cylindrical solid blocks having the same diameter as the inside diameter of the pipeline. Forced through the pipe by the pressure of the crude, the pig scrapes the walls of the flow line and pushes the build-up to a pig trap where the scale and other wastes are removed for recovery or disposal. Alternatively, heated oil injected into the flow line melts the paraffins.

Produced Fluid Treatment

Produced fluid at the wellhead is a complex mixture of gas, oil, water (often called produced water), and other impurities (such as sand and scale). A series of gravitational, chemical, and thermal treatment steps may be used to separate marketable gas and crude oil from the produced water and sand. The goal of treatment is to meet the delivery specifications of oil destined for the refinery or gas destined for the pipeline. Specific treatment units are described below. (See Figure 7.)

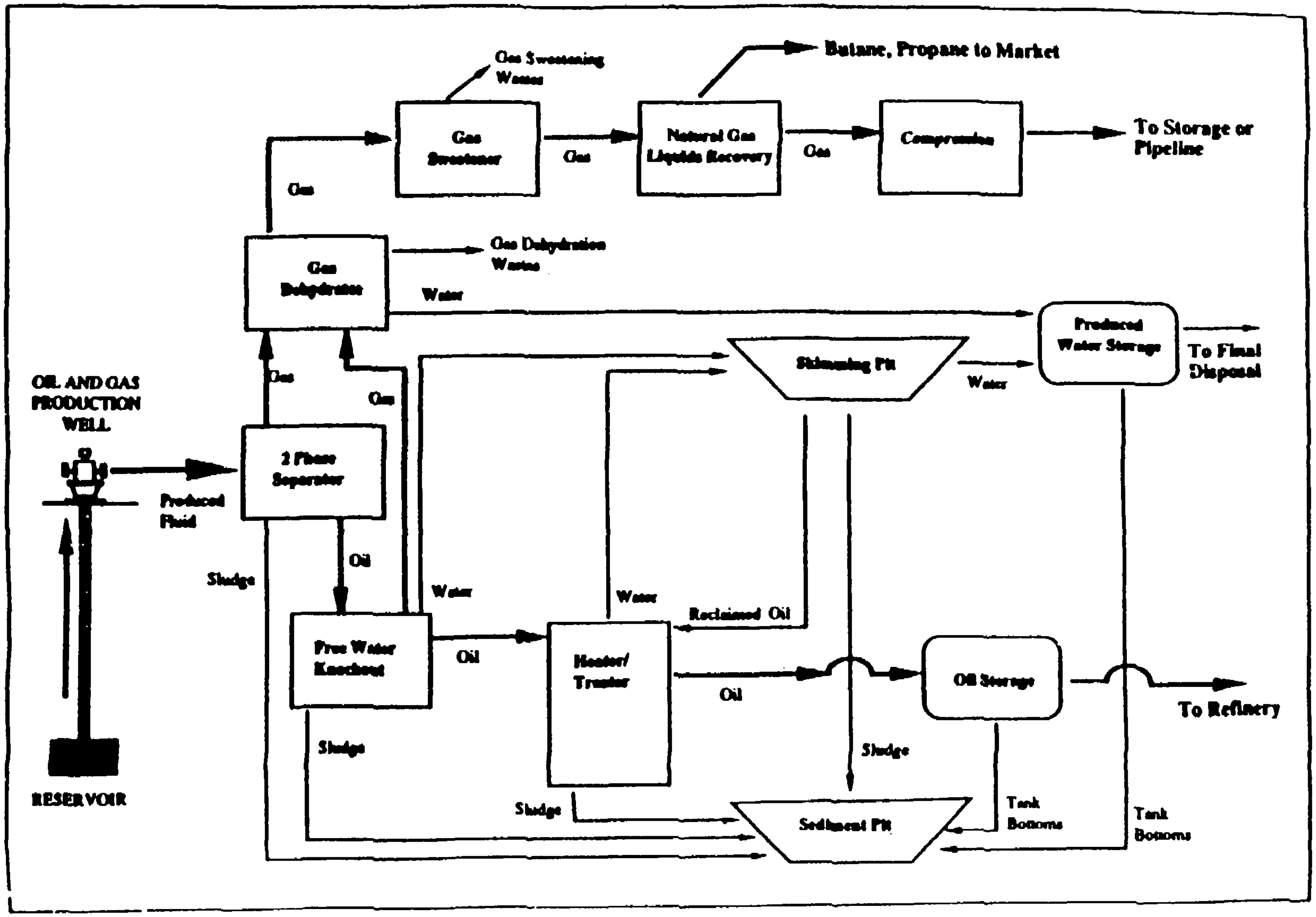
Two-phase Separator

Generally, produced fluid is first treated in a two-phase separator, which separates gas from the fluid phase of the mixture. In a two-phase separator, gas is allowed to rise above the produced fluids to a gas outlet while the remaining oil/water mixture is removed at the base. The gas flows to additional treatment units for dehydration, sweetening, and compression as described below. The oil/water mixture removed from a two-phase separator usually contains a high percentage of water. Much of this may be free water easily separated by gravity. If so, the fluids will be piped to a free-water knockout.

Three-phase Separator

If the lease is a gas producer (or produces a large quantity of gas with oil) the production facility will include a three-phase separator. Like a two-phase separator, gas and liquid phase fractions of the production stream are separated by gravity; the gas is removed from the top. The three-phase separator further splits the gas condensates or natural gas liquids (NGLs) from the water by gravity. Water is heavier than NGLs and so may be removed from the lowest portion of the tank, while NGLs may be skimmed from the fluid surface. More information on gas plants is presented below. At a gas field, when the only produced hydrocarbon is natural gas, an inlet separator may be used rather than a three-phase separator. For safety reasons, inlet separators are equipped with relief valves that vent to emergency containment (usually pits). In the event natural gas is flared, reporting to air quality and oil and gas regulatory agencies may be required depending on the composition and volume of the flare gas.

Figure 7. Flowchart of a Typical Oil and Gas Fluid Treatment System



Free-Water Knockout

A free-water knockout relies on gravity to separate gas, oil, and easily removed or "free" water to different outlets for separate treatment and to avoid unnecessarily heating too much water in subsequent treatments. The free-water knockout has a gas outlet at the top, oil outlet in the middle, and water outlet at the bottom. Gas removed from the free-water knockout is sent to a gas treatment facility while water is discharged to a skimming pit for further settling. The remaining oil/water mixture is piped to a heater treater.

Heater Treater

After removal of free water from the produced fluid, the remaining fluid is an emulsion, which is sent to a heater treater. Because of its polarity, water suspended in oil tends to form small droplets that are difficult to separate by gravity. Such emulsions, therefore, require heat to facilitate the water removal. So-called heater/treaters expose the fluid to a heat source in a closed tank. The heavier water falls to the bottom of the tank for removal. Any trapped gas or light hydrocarbons evaporated in the process rise to a gas outlet at the top of the tank. The resulting treated oil is then ready for storage and transport. The water is discharged to a skimming pit or produced water storage facility.

Gas Dehydration

Gas removed from either type of separator described above may still contain water in vapor form; this requires removal by dehydration. Gas dehydration typically uses a desiccant compound such as silica gel, glycol, methanol, or alumina to strip water from the product. If no sweetening (removal of hydrogen sulfide) is required, the gas is then ready for compression and storage or delivery. Water removed from the gas is piped to produced water storage facilities. The dehydration process may generate other wastes or require treatment for reclamation of dehydration compounds.

Sweetening/Sulfur Recovery

Some natural gas contains hydrogen sulfide, carbon dioxide, or other impurities that must be removed to meet specifications for pipeline sales and requirements for field fuel use. Sweetening consists of lowering the hydrogen sulfide and carbon dioxide content in natural gas. Hydrogen sulfide is removed from natural gas by contact with amine, sulfinol, iron sponge, caustic solutions, and other sulfur-converting chemicals. Heat regenerates amine or sulfinol for reuse.

The most popular method of hydrogen sulfide removal is amine treatment. This process is based on the concept that aliphatic alkanolamines will react with acid gases at moderate temperatures, and that the acid gases are released at slightly higher temperatures. Wastes generated in amine sweetening include spent amine, used filter media, and acid gas which must be flared, incinerated, or sent to a sulfur-recovery facility. Amine can be regenerated by heating and recycled to the process.

In the iron-sponge treatment, iron oxide reacts with hydrogen sulfide to form iron sulfide. Iron sponge is composed of finely divided iron oxide, coated on a carrier such as wood shavings. This process is generally used for treating gas at relatively modest pressure and hydrogen sulfide content. Wastes generated in the iron-sponge process are iron sulfide and wood shavings. Typically, in iron sponge operations, after the iron is consumed the waste iron sponge is removed and allowed to undergo oxidation, it is then buried onsite or taken to an offsite disposal facility. While incineration of spent iron sponge is possible, it is usually done in small quantities in locations where commercial incineration facilities are generally not available.

In caustic treatment, 15 to 20 percent (by weight) sodium hydroxide solution is typically used. Most caustic treatment consists of a simple vessel holding the caustic solution through which gas is allowed to bubble. Spent caustic is generated as a waste in this operation.

Dedicated sulfur-recovery facilities for high hydrogen-sulfide-content gas may use catalytic processes. Hydrogen sulfide is removed from sour gas using amine or sulfinol solutions. As part of the regeneration process, hydrogen sulfide is driven out of solution. The hydrogen sulfide is then burned in the presence of oxygen to produce sulfur dioxide. A mixture of hydrogen sulfide and sulfur dioxide, when passed over a heated catalyst, forms elemental sulfur. This is known as the Claus process. It uses inert aluminum oxide, in pellet form, as a catalyst. The catalyst does not react in the sulfur-making process. It simply provides a greater surface area to speed and assist the process.

Wastes associated with gas production include glycol, amine, sulfinol, caustic filter media, spent iron sponge, and/or slurries of sulfur and sodium salts. These wastes may contain light hydrocarbons and salts. Water from the dehydration process may be released as water vapor or, if it condenses, disposed of via Class II injection wells, National Pollutant Discharge Elimination System (NPDES) discharges, or in evaporation pits.

Natural Gas Liquids Recovery

Natural gas liquids recovery uses either compression and/or cooling processes, absorption processes, or cryogenic processes to separate butane, propane, and other natural gas liquids from methane. These processes either absorb heavier molecular compounds from the process stream with an absorption oil that is recycled or use temperature and pressure to separate fractions with different boiling points. Wastes generated include lubrication oils, spent or degraded absorption oil, waste waters, cooling-tower water, and boiler-blowdown water.

Compression

Plant compression and utility systems (fuel, electrical generators, steam equipment, pump, and sump systems) are necessary to operate gas plants and to raise the pressure of gas to match gas pipeline pressure. Compressors are driven by electric motors, internal combustion, or turbine engines. Wastes generated include lubrication oils, cooling waters, and debris such as rags, sorbents, and filters.

Skimming Pit

During the treatment stages described, the emphasis has been on the removal of produced water from gas and oil. In the process, however, a meaningful amount of petroleum may have been removed with the water. The primary function of the skimming pit, therefore, is to reclaim residual oil removed with the produced water. Because of the relatively high residence time for fluids in the skimming pit, much of the residual oil will rise to the surface where it may be recaptured and returned to the product flow line.

Solids Removal

An additional, valuable function has been served in treatment, the removal of produced sand and other particulates from the production stream. Each treatment vessel is equipped for the removal of accumulated sand and precipitates which settle by gravity at its base. These settled solids are removed to a sediment pit.

Because the settling of solids during treatment is incomplete, product-storage tanks tend to accumulate solids from further gravity precipitation. Tank bottoms, as they are called, are periodically removed from storage tanks by trap doors designed for this purpose. Tank-bottom material is stored in a sediment pit for later disposal.

Produced Water

Produced water may contain a number of pollutants in sufficient concentrations to pose environmental concern. The largest constituent of concern is generally chloride. Chloride concentrations may range from 50 ppt to well over 150 ppt, depending on specific geologic conditions. Cation concentrations typically associated with high chlorides in produced water are sodium, calcium, magnesium, and potassium, in decreasing order of abundance.

Because formation water is coproduced with hydrocarbons, the concentration of organics in the water removed from the production stream may be high. In addition to oil and grease, specific fractions found in produced water (as well as tank bottoms and pit sludges) may include benzene, naphthalene, toluene, phenanthrene, bromodichloromethane, 1,2 trichloroethane, and pentachlorophenol.

Additional pollutants are often found in produced water, arising both from downhole conditions and from production activities. Inorganic pollutants may include lead, arsenic, barium, antimony, sulphur, and zinc. Production chemicals such as acidizing and fracturing fluids, corrosion inhibitors, surfactants, and caustics will also generally be coproduced with formation fluids after being placed in formation.

Finally, Naturally Occurring Radioactive Material (NORM) is often found in produced fluids. Uranium, radon, and radium are among the most common radioactive species found to occur in formation fluids, with strontium and thorium detectable less frequently. Uranium tends to be resident in crude, while radon is divided in crude, gas, and water in decreasing concentrations. Radium is most often in produced water and scales.

Pipe scales, or cement-like solid precipitates found in production tubing, flowlines, and separator bottoms may contain barium, strontium, and radium sulfates. One industry analysis found the activity range of scales to be 50 to 30,000 pico Curies per gram (pCi/gm). Additionally, formation sand, found in tank bottoms, separators, and heater/treaters, may have an activity range of 0 to 250 pCi/gm. Soil contamination around production wells can range from 0 to 2,000 pCi/gm.

Waste Management

Exploration and Production Wastes

Exploration and production operations generate a number of wastes in conjunction with drilling activities, production of fluids, and treatment of produced fluids. Such wastes include used drilling fluids and drill cuttings, produced water, separator sludges and tank bottoms, produced sand, and so forth. The management of such wastes is typically an ongoing activity, often closely linked to the drilling or production process. As a result, the volume and characteristics of generically defined waste streams (such as separator sludges or pit contents) may differ dramatically from operator to operator both from geological factors as well as from the waste management techniques employed.

Used drilling fluids and drill cuttings are the largest waste streams associated with drilling. The coproduction of uneconomic substances with petroleum accounts for the greatest portion of wastes generated during production operations. Produced water, produced sand, sulfur compounds, NORM, and metals can occur in substantial quantities in petroleum bearing formations and must be separated from the production stream before delivery of crude or gas. Thus, depending on the water cut (percentage of produced fluids accounted for by water) and other qualities of the produced fluids, operators may face management of large volumes of waste.

In general, waste management at exploration and production sites revolves around the use of various pits and tanks for onsite storage of materials prior to disposal. Historically, the number of pits was small, sometimes only one, into which produced water and other accumulated wastes were placed. However, increasing regulations and costs of disposal for some waste types has generated an increase in attention paid to the potentially undesirable qualities of some wastes versus others. As a result, many operators employ multiple pits and tanks to sequester easily disposed materials from more problematic wastes.

A number of regulatory, economic, hydrologic, and geologic factors combine to determine final disposal options for wastes generated from exploration and production. For instance, any contemplated discharge of wastes (such as produced water or drilling fluids) to surface waters must be able to meet NPDES effluent criteria. Waste streams exceeding effluent criteria may require pretreatment which may be prohibitively expensive relative to other disposal options, such as deep well injection. Similarly, evaporation pits or surface spreading of tank bottoms may not be appropriate in areas with shallow ground water or nearby surface water, requiring alternative methods.

In some instances, exploration and production wastes may be disposed in fashions beneficial to some other uses. Beneficial uses of produced water include road spreading for ice and dust control, and irrigation with low chloride content waters. Tank bottoms may be used for road building. Among the most lucrative, beneficial uses of unwanted production stream contaminants is the production of elemental sulfur at gas sweetening plants. Recovered sulfur from natural gas processing accounted for roughly 15% of all U.S. sulfur production in 1988 (U.S. Bureau of Mines, Annual Report for Sulfur, 1990). Such beneficial uses stand to reduce overall waste disposal and site operation costs.

As discussed previously, the current RCRA exemption of many exploration and production wastes may have significant influence over operator decisions with respect to waste management. Because of RCRA, operators often try to sequester exempt and non-exempt wastes subject to regulation. For example, unused stimulation fluids are explicitly specified as non-exempt wastes. Mixing unused acids with spent workover fluids may trigger RCRA inclusion such that the total volume of workover wastes would require handling as under Subtitle C rather than only the (presumably) much smaller volume of unused acids.

Aside from RCRA, other state and local regulations may tend to promote source separation at drilling and production sites. For instance, mixing low Ph workover wastes with produced waters may make it difficult to achieve permitted NPDES effluent limitations. Similarly, mixing high chloride or hydrocarbon content wastes with drilling muds may affect loading rates for landfarming, increasing the area or time needed for disposal, and hence the costs.

Since both prevailing regulations and waste constituents can influence disposal options and costs, waste management strategies may be closely linked to typically engineering-dominated operation decisions. This relationship is typified in waste minimization efforts increasingly practiced at exploration and production sites. Closed cycle mud systems reduce both mud and waste management costs by reducing the total volume of drilling fluids employed. Water flooding projects simultaneously dispose of produced waters while using them to increase oil recovery. Casing vent gas recovery systems sometimes used in conjunction with steam flooding projects can increase production flow rates and NGL recovery while eliminating a source of air emissions.

The following sections describe predominant waste management practices employed in conjunction with exploration and production operations.

Reserve Pits

During drilling operations used drilling fluids, cuttings, and other wastes accumulate onsite. The reserve pit serves as the primary storage unit for such wastes, often along with make-up water used in mud preparation. Usually located next to the rig, reserve pits can generally accommodate 2 or 3 times the projected total mud volume for the well being drilled. Depending on regulatory constraints, hydrogeological conditions and mud design, reserve pits may require clay or synthetic liners to prevent vertical migration of pit contents. In some instances an above-ground basin or tank may replace the more typical excavated pit.

Pit contents vary with mud design, formation geology, and operator practices. In addition to used drilling fluids and cuttings, the pit may receive cement returns, rain water, unused mud additives, rig wash, and miscellaneous oil field chemicals. If salt water muds are used, or if drilling encounters salt domes, the chloride content of pit wastes may be quite high. Similarly, oil based drilling muds may substantially increase the hydrocarbon content of drilling wastes. Since the reserve pit may remain open for some time after the initiation of production (6-12 months in modern operations) the possibility exists for the commingling of various completion and/or production related wastes with drilling wastes.

Reserve pits have been found to contain chloride concentrations from 570 to 135,000 mg/l. Oil and grease concentrations may range from 800 to 280,00 mg/l. Barium (resulting from the use of barite as a weighting agent in muds) can range from 30 to 56,200 mg/l. Other constituents of concern include benzene, phenanthrene, naphthalene, toluene, and other volatile and semivolatile organics. Various metals may be present including aluminum, iron, cadmium, chromium, and lead.

Reserve pits may serve as temporary or permanent disposal units for some or all of the wastes they contain. Depending on prevailing regulatory conditions as well as hydrogeological conditions and pit contents, some or all of the wastes may be buried in the pit. Alternatively, a number of onsite and offsite disposal practices may be utilized.

In many instances, operators backfill reserve pits with native soil for permanent disposal of drilling wastes. Generally, burial is preceded by dewatering of pit contents. In situ solidification of wastes using commercial cement, flash or lime kiln dust may serve to reduce waste constituent mobility prior to burial.

Reserve pit wastes may be disposed of in additional ways, such as surface water discharge and landfarming. These methods are discussed separately in conjunction with management of production related wastes.

Annular Disposal of Drilling Wastes

In instances where onsite burial is not feasible (e.g., high chloride or metals concentrations) operators may dispose of pit wastes via annular injection. Pumpable reserve pit wastes are injected into the annular space of the well. This is different from underground injection in that wastes are contained in the well bore and not in an underground formation. Annular injection does not remove the need to cement plug USDWs.

Centralized Disposal Pits

For economic, lease restriction, or regulatory reasons some operators may dispose of reserve pit wastes at offsite disposal pits. Wastes are transported to such centralized facilities in vacuum trucks. (Additional information on centralized facilities appears below.)

Drilling Waste Minimization

Because of the potentially high costs of transportation and/or disposal or large volumes of drilling wastes, some operators reduce waste burdens through the use of closed mud systems and mud recycling. Closed mud systems can reduce the total volume of drilling fluids used (and hence disposed) by efficiently recirculating mud returns after removal of cuttings. Such systems may recirculate either liquid or solid mud phases or both, depending on design.

Alternatively, some operators may reduce mud and waste disposal costs through recycling of used muds. Most appropriate for higher cost, oil-based muds, areas where onsite or near-site disposal is difficult, or in fields with multiple wells scheduled for drilling, mud recycling relies on the removal of cuttings and chemical reconditioning to retain needed mud properties. Only drill cuttings and residual muds require disposal.

Storage, Settling, and Skimming Pits and Tanks

Wastes removed from the production stream require onsite storage prior to disposal. Such wastes include produced water from separators and dehydrators, untreatable emulsions from the heater/treater, separator sludges, tank bottoms, and sweetening and dehydration wastes. They may be stored in pits or tanks, separately or together.

Produced water discharged from the various treatment units onsite can vary with respect to solids content, oil and grease, and emulsions (among other things). Water with high solids or hydrocarbons content may require additional settling time for solids removal and skimming of petroleum for recovery. Settling/skimming pits receive such waters prior to storage in tanks or other pits. Removed hydrocarbons return to the production stream while settled solids may periodically be removed from the pit and stored in a sediment pit.

Two- and three-phase separators, free-water knockouts, and heater/treaters continuously accumulate solid material precipitating from the production stream. Produced sand, silt, paraffins, sulfates and other substances along with water and residual hydrocarbons account for the bulk of these sludges. Separator sludges must be removed periodically, usually discharged to a sediment pit or tank. Both produced water and product storage tanks also accumulate settled solids over time, requiring removal. These tank bottoms may be added to settling pit contents.

Underground Injection

As described earlier, produced water is the largest volume waste generated from oil and gas production activities. Nationally, approximately 90 percent of all produced water is disposed through injection wells permitted under EPA's UIC program. Much of this water is injected in conjunction with water or steam flooding enhanced oil recovery. The remainder of the 90 percent is disposed in deep injection disposal wells or through annular injection.

The use of produced water for water or stream flooding generally requires pretreatment of water. Depending on water quality, pretreatment may involve little more than the addition of corrosion inhibitors to protect the integrity of injection wells. In some cases, however, solids, oil and grease, and other impurities in the waste could damage wells and foul injectors. As a result, water and stream flooding projects may require installation of onsite water treatment facilities. Wastes removed from the injection water may be stored in tanks or pits with other oil field wastes or injected in deep disposal wells.

Deep well and annular injection of produced water involves pumping waste fluids to some formation for permanent disposal. In deep well injection, the injection zone is known. The injection may be the original producing formation, salt water formations, or older depleted formations. The UIC program requirements typically specify design, monitoring, and injection pressure restrictions for injection well operators.

Annular injection involves the injection of produced water down the tubing/casing or surface casing/intermediate casing annulus of a nonproducing well. While the specific injection zone may not be known, all known USDWs generally must still be protected with cement plugs.

Discharge of Produced Waters to Surface Water

In some cases, operators may discharge produced water to surface receiving waters. Such discharges require NPDES permits stipulating allowable concentrations of contaminants in the effluent. As a result, produced waters may require pretreatment before release. Typical constituents which may exceed permitted levels include chlorides, oil and grease, total dissolved solids (TDS), pH and sulfates.

Evaporation and Percolation Pits

Evaporation and percolation pits are used for disposal of produced waters. Evaporation pits are typically lined with a clay or synthetic liner, while percolation pits are unlined, allowing waters to seep into soils. The feasibility of either evaporation or percolation pits depends in part on area hydrology and constituent concentrations of the wastes. Operators may construct individual evaporation pits for each site or field, or may haul or pipe waters to centralized facilities servicing multiple operations.

Land Farming

As alternatives to burial of reserve pit solids, pit sludges and other solid and semi-solid wastes, land application may be employed for disposal of these wastes. Land farming of pit wastes typically involves the thin spreading of wastes over soil with or without mechanical tilling to promote biological degradation, adsorption, and dilution of constituents. Depending on intended uses of the area of treatment, loading rates may be modified. Some state and local regulations restrict loading rates according to the total burden of given constituents per unit area of treatment (e.g., kilogram oil and grease per hectare, Kg/Ha).

Often practiced in conjunction with final reserve pit or site closure, land farming may allow rapid revegetation of the affected area. Factors influencing site soil quality and productivity include total chloride deposition, oil and grease concentrations, and the presence of plant-specific phytotoxic constituents. Commercial land farming facilities present additional options for operators.

Surface Spreading of Produced Waters

Several surface spreading methods of produced water disposal may be practiced by operators. For low to moderate salt content waters, produced water may be used for road spreading, both as a dust suppressant as well as a surface deicer. Road spreading may require some level of treatment prior to use. Oil and grease concentrations, Ph, and NORM may be regulated by state or local agencies.

Use of Produced Water for Irrigation

The NPDES program exempts from permitting requirements surface discharges of waters determined to be beneficial to agriculture (limited to west half of U.S.). Therefore, treated produced water may be discharged to irrigation canals or other conduits for agricultural purposes. Some operators dispose of produced waters after treatment in water recycling plants directly to irrigation canals. The level of water treatment often required for stream flooding projects may be sufficient to allow such discharges, providing lease operators with the option of disposing of excess treated water in this manner.

Central Treatment Facilities

Many operators utilize central treatment facilities for disposal of non-exempt and some exempt wastes. Such central facilities may have both Class I and Class II injection wells, incinerators, evaporation pits, land treatment areas, and/or reclamation capabilities. Utilized by small operators and in areas where specific disposal problems exist, central treatment facilities generally have sufficient capacity to handle wastes from several production operations.

Crude Oil Reclaimers

Crude oil reclaimers are independent operators who handle various oil field wastes in an effort to collect and resell residual oils from the wastes. Candidate wastes include paraffins and pigging wastes and tank bottoms. Reclaimers use gravitational, thermal, and chemical means to separate crude from produced water and sludges and to "break" tight emulsions.

Note that crude oil reclaimer wastes are <u>not</u> categorically exempted from RCRA Subtitle C. Pending a final notice of clarification, EPA has tentatively concluded that wastes derived from the processing of only exempt wastes are themselves exempt. thus, commingling of exempt and nonexempt wastes either prior to or after processing could result in the entire waste stream becoming subject to costly Subtitle C requirements.

Road Building Materials

As an alternative to burial or offsite disposal of tank bottom and settling pit wastes, some operators use these materials for the paving of on-lease road surfaces. This use may require pretreatment of tank bottoms to neutralize heavy metals or other hazardous substances prior to application. Typically, sediments are dewatered prior to mixing with other road construction materials, and then applied to road surfaces.

Casing Vent Gas Recovery

Steam flooding projects typically result in an increase in the pressure of formation gases entering production well casings. Gases present may include natural gas, hydrogen sulfide, and lighter organic compounds volatilized with the increased formation temperatures resulting from the infusion of steam. Historically vented from casing vents directly to the atmosphere, these waste gases may be regulated under CAA authorized state implementation plans or other regulations. Some operators control the emission of casing vent gas by drawing the gases into a recovery system. The system separates condensible NGLs from H_2S and other gases and returns them to production flow lines. Concurrently, sulfur dioxide scrubbers remove sulfur compounds from the exhaust of a natural gas flaring unit. Such systems can increase NGL recovery and increase product flow rates by reducing well back pressure otherwise created by the gases. Additionally, hydrocarbon and SO_2 emissions are substantially reduced.

Gas Flares

Oil fields may produce gas below a level at which it would be economical to collect. Left to escape to the air uncombusted, vented natural gas can create a risk of explosion at the site. As a result, some operators will flare (burn) the waste gas. Because waste gas may contain hydrogen sulfide, some operators may be required to scrub flare exhaust for removal of sulfur dioxide produced in combustion of hydrogen sulfide.

Miscellaneous and Nonexempt Oil Field Wastes

Exploration and production operations require the operation of industrial machinery and the handling of a variety of compounds for cleaning, product and waste treatment, maintenance of systems, etc. Many of these wastes may be nonhazardous industrial wastes disposable at conventional landfills or onsite. Others may be nonexempt substances subject to RCRA Subtitle C requirements. Failure to segregate nonexempt wastes may void the exemption for commingled exempt wastes.

Site Closure

As a particular well or well field's reserves diminish and it becomes uneconomical to continue to produce, the operator may decide to stop production and close or abandon the site. Closing the facility may entail properly abandoning the wells by removing equipment and plugging the borehole, as discussed in the well abandonment section. Reserve pits and other excavations associated with the site may be closed (see the waste management section) and the site may be regraded. Typically, any pumping, gathering, or production equipment onsite is removed for use at other operating sites. The drill pad may be regraded and any roads may be ripped to break up the hard packed surface and restore natural soil consistency. If wastes have been disposed of onsite (e.g., land application, burial in reserve pits, etc.), special consideration of permanent containment capability may be necessary.

After site closure (dismantling of equipment and closure of onsite waste units), reclamation may be conducted. If top soil was segregated and stored during initial land disturbing operations, this top soil is spread over the disturbed areas, and the entire site may be reseeded (possibly with native species). Effective reclamation may take several growing seasons to accomplish.

The activities undertaken during site closure and reclamation may depend on state and/or Federal reclamation requirements and the amount of bond held by these authorities to ensure proper closure and reclamation.

COALBED METHANE DEVELOPMENT

In recent years, coalbed methane has emerged as a viable alternative source of natural gas. Historically viewed as a hazard to coal mining requiring pre-mining degasification and constant ventilation, coalbed gas can now be economically produced both in conjunction with mining operations as well as in formations too deep for underground mining. (Mills, R.A. and J.W. Stevenson, May 13, 1991.) Coalbed gas production typically relies on conventional gas techniques, often with modifications to accommodate the differing nature of the source rock. This section reviews the nature of coalbed gas and distinctive practices associated with its development.

Nature of the Resource

Unlike conventional sand or sandstone reservoirs, in which migratory free gas occupies voids in the formation, coal formations contain sorbed gases, typically methane and carbon dioxide, which developed in-situ as by-products of the coalification process itself. These gases occupy surface sites throughout the coal matrix. Because the internal surface area of coal can be quite large (roughly one billion square feet per ton of coal), the gas content of coal seams can far exceed the volume of gas contained in an equivalent area of conventional gas reservoirs. (Kuuskraa, V.A., and C.F. Brandenburg, October 9, 1989.)

All coal contains some methane. The methane content of coal generally varies with its rank (the higher the coal rank the higher the contained gas) and its depth (the deeper the coal the higher the higher the contained gas). In particular, the depth of the coal seam determines in part the formation pressure. The sorption of gas to coal surfaces is a function of formation pressure. The "desorption isotherm" describes the pressure at which gas will begin to desorb (volatilize) as a function of temperature. (Schraufnagel, R.A., et al, May 13, 1991.)

Coal seams are generally saturated with water. Hydrostatic pressure from formation water contributes to the overall formation pressure, and hence the sorption of gas. Thus, the desorption isotherm determines the extent to which hydrostatic pressure may be reduced to liberate methane from the coal. (Schraufnagel, R.A., et al, May 13, 1991.)

The network of intersecting fractures within the seam, called "cleats", determines the permeability of the formation. (Puri, R. et. al., May 13, 1991.) Cleats allow the movement of fluids and gases within the formation. As with conventional gas reservoirs, the permeability of a coalbed can be enhanced though hydrofracturing, inducing the propagation of fractures outward from the well bore.

Factors such as gas content, formation pressure, permeability, and water pressure together determine if a coal seam's gas can be economically produced. For instance, a seam with low gas content and high hydrastatic pressure relative to the desorption isotherm would require excesive water production for the amount of methane produced. Similarly, a formation with very low permeability will require extensive fracturing in order to produce the gas contained. Failure of such stimulation techniques would prohibit gas production.

Types of Coalbed Development Projects

Among the types of coalbed gas development projects commonly practiced are: vertical degasification wells in advance of mining; horizontal degasification wells; vertical gob gas wells; and vertical gas wells independent of mining. Gas well development projects in conjunction with mining initially emerged as techniques to minimize the risks posed by coal gas to mining operations, and to minimize the volume of air needed to ventilate mine workings. However, mine operators and cooperative ventures between the mines and gas developers have evolved to allow profitable production and sale of the gas, rather than simply venting the gas to the atmosphere. Experience with degasification of mines ultimately led to gas development projects independent of mining.

Vertical Degasification Wells in Advance of Mining

Prior to mining a coal seam, vertical degasification wells may be drilled to within a short distance above the seam or into the seam itself. Degasification wells require conventional gas well drilling techniques, though well bores will tend to be smaller than those for conventional gas production. These wells serve to partially remove coal seam gas and reduce formation water prior to mining. Produced gas may be sold after surface treatment and compression.

Horizontal Degasification Wells

Within a mine, horizontal wells may be drilled in advance of mining hundreds of meters into the coal seam to reduce the methane content of the coal to be mined. In this scheme, low pressure gas is collected in large pipes leading to main or ventilation shafts to the surface. The gas may be released to the atmosphere or sold. Sale of the gas, however, requires considerable compression capacity and may require removal of carbon dioxide.

Gob Gas Wells

Modern coal mining often involves the use of long-wall mining techniques. In long-wall mining, a panel up to hundreds of meters wide is constructed. The panel is a mobile machine with a self-supporting roof. As the panel advances, subsidence occurs in the already mined area behind it. This subsidence results in a highly fractured "rubblized" zone, called the gob, often extending hundreds of feet above the seam. (Mills, R.A. and J.W. Stevenson, May 13, 1991.) Gas accumulates in this highly permeable zone and can spill back into the mine, creating a high risk of explosion.

Gob gas wells are intended to remove methane from the top of the gob before accumulation is sufficient to migrate into the mine. Drilled to within a short distance above the top of the mine, these wells produce low-pressured gas of potentially high carbon dioxide content. Production may be treated and repressurized for sale or may be vented to the atmosphere.

Vertical Gas Wells Independent of Mining

Much of the recent interest in coalbed gas development has focused on projects independent of mining. In such projects, the aim is to produce gas from coal formations in much the same manner as gas is produced from conventional formations. To date, target coal seams include formations too deep for underground coal mining as well as formations containing multiple adjacent coal-bearing strata of varying widths.

Degasification projects or other coalbed gas production performed in conjunction with mining operations are beyond the scope of this document. The above operations have been introduced to indicate the range of coalbed gas projects existing. The remainder of the discussion will be limited to dedicated gas production operations only.

Coalbed Methane Well Drilling and Completion

Most coalbed gas wells are drilled using conventional oil and gas drilling practices. Typical practices include using rotary rigs to dill 7 7/8 to 9 1/2 inch holes, depending on desired casing and tubing sizes. Often, smaller-bore holes may be employed to reduce drilling costs. In the western states, operators may site wells on the drilling pads built for conventional gas wells to minimize land development costs. (Logan, T.L. 1989-1990.) Water-based drilling fluids are generally preferred over oil-based or foam muds, both to reduce costs as well as to reduce potential formation damages. Finally, typical drilling operations may use portable tanks to contain drilling fluids, with small on-site pits built to accomodate excess down-hole fluids and large mud returns.

One of the primary concerns when drilling into the coal seam(s) is the possibility of formation damage. Such damages may result from the irreversible sorption of drilling mud constituents to the coal near the well-bore, decreasing permeability. (Puri, R. et. al., May 13, 1991.) Additionally coal fragments and fines may clog fractures near the well-bore, further reducing permeability. Accordingly, operators may opt to drill a well under-pressured such that fines and fluids remain in the well-bore, to be flushed out during completion. (Logan, T.L. 1989-1990.)

A number of completion techniques are utilized for coalbed gas wells depending on formation conditions and production strategies. These include open hole completion, open hole cavity completion, and cased-hole completions with either slotted or perforated casing. Any of these techniques may be used in conjunction with fracturing treatments and/or other stimulation techniques.

Open hole completions require drilling to the top of the formation, casing to just above the formation, and then drilling through the seam far enough to provide a sump or "rat hole" for fines and other down hole debris to accumulate. While common, such wells can experience difficulties with fouling of pumps and decreased permeability from accumulation of fines and down-hole sloughing. (Lambert, S.W., S.L. Graves, and A.H. Jones, 1989-1990)

An alternative open-hole strategy involves drilling through the seam, casing to above the formation, and then creating a large cavity around the well bore by "surging" the well. The cavity forms as a result of coal caving, with material allowed to fall to the bottom of the hole. After cleaning out residual debris, pre-perforated casing is installed in the production zone. While presenting less difficulty from accumulation of fines, this completion technique entails a risk of drill pipe and casing getting lodged in the bottom of the hole, requiring recompletion. (Logan, T.L. 1989-1990.) It is important to note that while either open-hole completion technique will allow fracturing treatment, neither provides a good opportunity to produce from multiple seams. Lambert, S.W., S.L. Graves, and A.H. Jones, 1989-1990.)

Cased-hole completions require drilling though the coal seam(s), casing to beneath the lowest target zone, and cementing the casing string across the zones. The casing is then perforated using a perforation gun or similar method. Both cement and completion fluids may cause formation damage due to irreversible sorption of completion fluid constituents or blockage of the fractures with cement or debris. Again, risk of formation damage may be reduced if the well is completed slightly under-pressured. Cased-hole completions afford the best opportunity to produce from multiple seams.

Coalbed Methane Well Stimulation

As coalbed gas technology evolves, dispute continues over which stimulation methods produce the best results. Choice of stimulation techniques depend on the number of seams to be developed, the depth, thickness, and pressure of target seams, and a number of other factors. Some level of success has been achieved with hydrofracturing both using water and using crosslinked gel as the fracturing fluid. Gels provide the advantage of being able to carry greater amounts of proppant per unit volume of fluid, but may sorb to the coal causing swelling and thus loss of permeability. (Palmer, I.D., et al. May 13, 1991.) Additionally, flushing of fracturing fluid with water/acid mixtures may only partially mitigate the sorption problem. Water can carry less proppant, but is substantially cheaper than gels, and will not sorb to the coal. (Schraufnagel, R.A., et al., May 13, 1991.)

Coalbed Methane Production

As described earlier, coalbed methane production requires reduction of formation pressure below the level at which gas begins to desorb from the coal. This is accomplished through removal of water, thereby reducing the hydrostatic pressure within the coal seam. Once the well is completed and production tubing is installed, water enters the wellbore and is pumped to the surface. As water production continues, formation pressure begins to decrease toward the desorption isotherm, allowing sorbed gas to volatilize. The greater the decrease in pressure, the faster the liberation of the gas. As a result, coalbed wells often exhibit a phenomenon known as "negative decline" in which gas output increases over time to a plateau prior to declining. This is in contrast to conventional oil and gas wells, which achieve peak production at the outset of flow into the well and fall off continuously thereafter.

Initially, water production from coalbed gas wells is very high. Little or no gas is present in the flow as pressure still exceeds the desorption pressure for the reservoir. As the pressure drops, gas begins to desorb, travelling with the water toward the well bore. Finally, once water pressure has dropped significantly, free gas and water enter the well. (McElhiney, J.E., R.A. Koenig, and R.A. Schraufnagel, 1989-1990.) The time from initial pumping to production of gas may be anywhere from a few days to years. (Burkett, W.C., et al., May 13, 1991.)

Production facilities at coalbed methane sites will roughly mimic those at conventional gas sites, with differences in scale. Because water is co-produced with coalbed gas, a free water knockout or other separator will generally be present. On-site water storage tanks at coalbed gas sites will be larger or require more frequent emptying than those at conventional gas sites. Further, evidence suggests that coalbed gas rarely requires sulfur removal (sweetening).[1]

Coalbed gas sites may also require greater compression capacity than their conventional gas counterparts. Generally, some compression is required to pipe produced gas to central compression/treatment facilities. However, production pressures for coalbed gas wells can often be well below transportation pipeline pressures.

Water production from coalbed gas wells generally falls over time to a minimum value. This minimum value (different for each well) generally exceeds the water production rate experienced from conventional gas wells. However, produced water quality from coalbed wells generally exceeds that

[1]. In all the documents reviewed for this report, no mention of sweetening appeared. Though coals may have high sulfur content, the authors have seen no indication that gases from such formations may contain sulfur compounds.

from conventional oil and gas wells. For instance, in eastern basins average TDS values equal roughly 4000 mg/l, while in western basins average TDS values roughly equal 1000 mg/l. For both regions, constituents of concern appear limited to iron and manganese. (Lee-Ryan, P.B., et al., May 13, 1991.)

Coalbed Methane Waste Management

Coalbed methane projects generally do not require unique waste management practices. Exploration and development wastes from coalbed projects will be similar to those from oil and gas projects as techniques and materials used are generally the same. As noted above, the largest waste stream from coalbed gas production is produced water. While typically larger than the volume produced in conjunction with conventional gas production, coalbed gas produced waters may be less than those associated with oil production, and are of generally higher quality. Treatment of produced water typically requires solids separation in settling ponds prior to surface water discharge or deep well injection.

It is worth noting that coalbed wells may require more frequent workovers than conventional gas wells. The need for workovers (up to 4 times per year) results from the accumulation of coal fines and debris down hole, causing pump failures and loss of permeability. (Schraufnagel, R.A., et al., May 13, 1991.) More frequent workovers would entail greater generation of workover wastes.

The remainder of this document discusses potential environmental impacts associated with oil and gas exploration and production operations. Coalbed methane projects will be considered along with conventional oil and gas operations in the analysis. Accordingly, explicit mention of coalbed methane projects will occur only in those instances where potential impacts are unique to, or otherwise distinguishable for, these projects.

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS

The descriptions of potential environmental impacts below are based on specific examples of documented damages caused by oil and gas exploration and production activities. The list of impacts is not comprehensive, nor does every oil and gas activity provide the potential to cause each possible impact described. Rather, potential impacts are identified and discussed in a conceptual framework, with the variables associated with each concept described where possible. In general, research may be necessary to determine site-specific potential impacts.

This section is organized first by media or topic (ground-water, surface water, soil, air, ecosystems and land use). The media-specific sections are then organized by oil and gas activity (exploration and development, production, and waste management) with specific issues or concepts that identify potential impacts described under each activity. The ecosystems section is described in terms of ecosystems (coastal, inland), with concepts and their variables described, and the land use section identifies typical land use activities (e.g., grazing, etc.) and how they might be impacted by oil and gas activities.

POTENTIAL IMPACTS ON GROUND WATER

Ground water refers to water saturating an area or zone below the surface. This zone is referred to as an aquifer if it is capable of producing usable quantities of fresh or potable water. Approximately half of the U.S. population and 95 percent of the rural population use ground water as drinking water. Typically, ground water flows at a very slow rate compared to surface water, and may be recharged by surface water and precipitation. Groundwater may naturally discharge to surfaces waters through springs to the ground's surface or to existing surface water bodies (lakes, streams, etc.).

Identified below are many of the potential impacts to ground water associated with oil and gas operations. These impacts represent pathways for ground-water contamination with possible subsequent impacts to human health and the environment or loss of available ground water with subsequent impacts on availability of potable water and potential dewatering of surface water bodies (e.g., wetlands, etc.). It is again emphasized that site-specific factors (e.g., activities, environmental setting, etc.) determine potential and actual impacts at individual sites.

Exploratory and Development Drilling

Potential impacts to ground water from exploration and development may be a direct result of drilling a hole from the surface, through the unsaturated zone, through the saturated zones (aquifers) and into potential oil producing formations. Often, oil producing zones are also saline water zones, with potential constituents of concern not limited to hydrocarbons, but also including salts and metals. Specific potential impacts are described below.

Vertical Migration of Contaminants

Potential for ground water impacts stems from the storage of drilling fluids, reserve pit wastes, and other fluid stocks (diesel fuel, mud additives) on the surface with the well acting as a potential conduit for released contaminants. Tank or pit seepage or failure, and site runoff may result in migration of contaminants to surficial aquifers. The historic practice of using unlined reserve and mud pits (possibly excavated to below the water table), still used today in some areas, has resulted in instances of ground-water contamination. In addition, the well may act as a conduit between production formations (with hydrocarbon and other contaminants) and usable aquifers. If the well is not cased or the casing and grouting have failed, there is increased potential for migration of contaminants. The extent of potential impacts depends on the volume and constituents of escaping fluids, the depth to ground water, and soil characteristics. Constituents of concern include hydrocarbons, heavy metals, and chlorides.

Ground-water Drawdown

As the well is drilled through water bearing zones, water may discharge from these zones (possibly aquifers) and be pumped to the surface with the mud, potentially resulting in localized aquifer drawdown. However, when water bearing zones are encountered, operators may attempt to quickly prevent the discharge of fresh water to the mud column, as this may cause the clays (e.g., bentonite) in the mud to swell and lose their effectiveness.

Production

For the purposes of the section below, primary production is taken to include artificial lift production with no manipulation of formation energy or downhole properties of the product. Potential impacts from downhole activities associated with each phase of production are discussed prior to potential impacts from surface activities common to all phases of production. Some of the methods discussed do not apply to gas production.

Migration of Stimulation Fluid to Ground Water

Stimulation of production zones through hydraulic fracturing may result in impacts to ground water. In general, stimulation attempts to enhance the movement of formation fluids toward the well bore by increasing formation permeability or creating channels (fractures) along which fluids may travel. If pressure-induced fractures extend beyond the production zone, impacts to ground water may occur due to migration of fracturing fluids to aquifers.

In the case of coalbed methane wells in the eastern U.S., potential for impacts to groundwater from migration of fracturing fluids may be increased due to the often shallow depths of target coal seams.

Damage and Blowout of Existing Wells

In some instances, the downhole pressure created by hydraulic or explosive fracturing may cause damages to nearby water wells or abandoned wells. If the pressure is great enough, well blowouts can occur, resulting in contamination of ground water with fracturing fluids and hydrocarbons.

In the case of coalbed methane wells in the eastern U.S., potential for impacts to existing wells from hydraulic fracturing may be increased due to the often shallow depths of target coal seams.

Migration of Injected Water to Ground Water

Waterflooding presents the potential for contamination of ground water with injected water (often produced brines). Thief zones (naturally fractured shales) or other formation irregularities may allow the migration of injected waters to freshwater zones. Migration may also arise from leaks in injection well casing. Constituents of concern include brines, trace contaminants of produced waters, and hydrocarbons. (See Figure 8.)

Of additional concern is the possible location of abandoned, improperly plugged wells or freshwater wells in hydrologic contact with the injection zones, which may act as conduits of injected waters or may be impacted by the increase in formation pressure. The potential for impacts from injected waters via abandoned wells depends on the geology in the area, the relative pressures of the injection zone and the aquifer in question, and the type, location, and condition of the abandoned well.

Migration of Steam and Other Injected Solutions to Ground Water

Both steam injection and chemical flooding present the potential for the unintended migration of injected fluids and/or hydrocarbons to aquifers or nearby wells. The extent of potential impacts depends on, among other factors, the nature of the injected fluids. Steam, often from produced water, may be highly saline. Chemical flooding may contain surfactants, polymers, and alkaline solutions. As with waterflooding, abandoned wells drilled to the same formation may serve as conductors of injected solutions to aquifers.

Potential Damages from In-situ Combustion

In-situ combustion, rarely used, presents potential impacts similar to those from the methods described above. In addition, in-situ combustion may result in significant damage to well casings, promoting the communication of fluids between fluid-bearing zones.

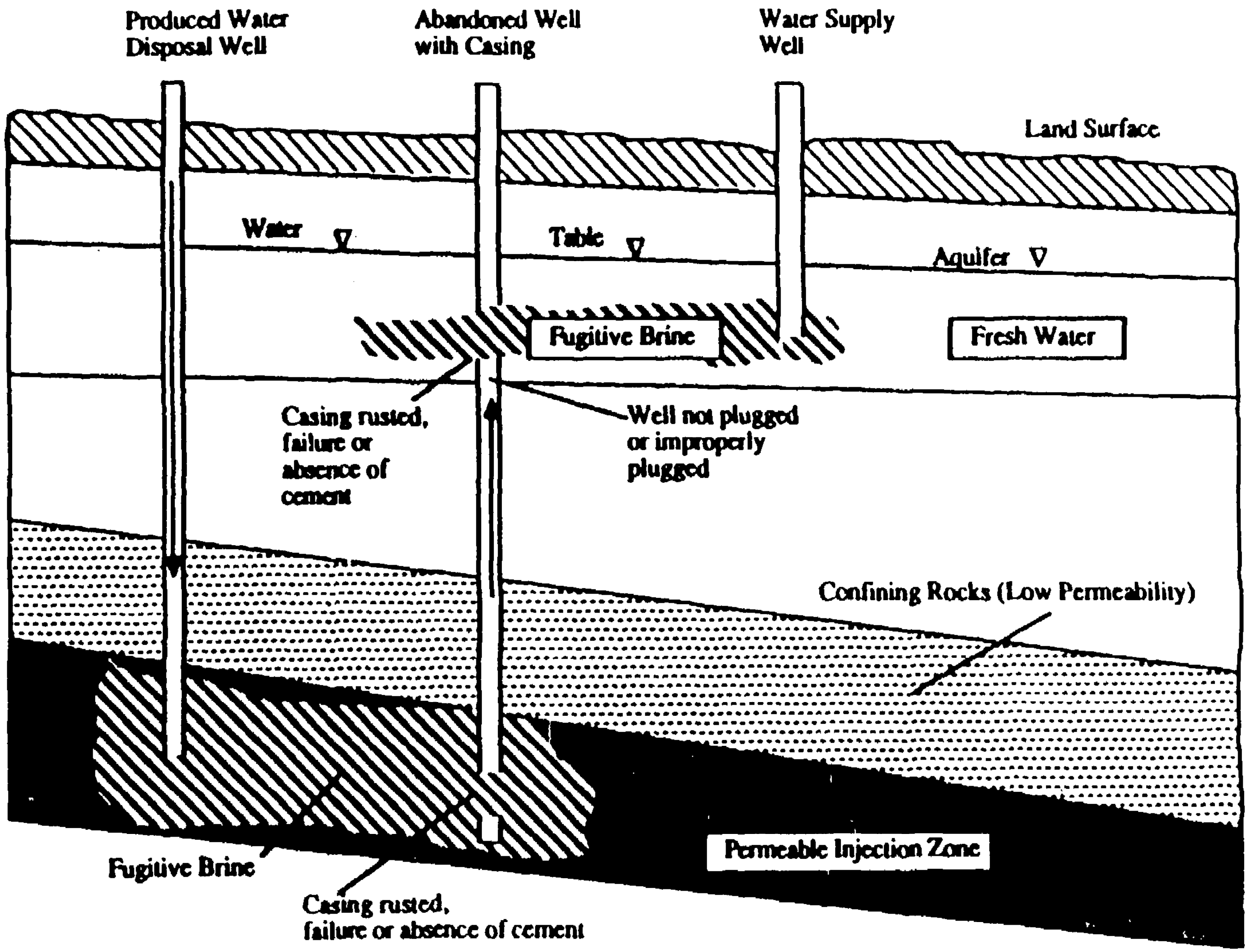
Migration of Gathering Line Spills to Ground Water

Product pumped to the surface from one or many wells on a lease must be collected in gathering lines leading to treatment and storage facilities. Corrosion, chronic leaks or failure of gathering lines may result in migration of hydrocarbons to shallow ground water.

Product Stock Tank Leakage

Oil and gas stocks may be stored in surface or underground tanks prior to delivery. Leakage from storage tanks may result in migration to ground waters. The extent of potential impacts depends on the extent and duration of any release.

Figure 8. Schematic Diagram of Contamination of an Aquifer with Brine



After: U.S. Environmental Protection Agency, 1987.

Waste Management

Some waste management activities at oil and gas operations are closely intertwined with general fluid management practices. For instance, maintenance of mud and reserve pits serves a need for storage of fluids in use as well as storage of waste materials generated during drilling activities. Landfarming of drilling muds after pit closure, on the other hand, is performed explicitly for the purposes of waste management. Some fluid management practices as well as explicit waste management practices may potentially impact ground waters.

Migration of Deep Well Injected Fluids

Nationwide, roughly 90% of produced waters are injected in deep wells, either for enhanced oil recovery or deep well disposal. Additionally, other oil field fluids may be deep well injected. As with waterflooding, discussed above, improper casing installation and/or corrosion of casing can lead to migration of wastes from the injection formation or the well to aquifers. Further, the presence of abandoned wells drilled to the same formation presents the potential for migration of injected fluids to aquifers.

Migration of Annular Injected Fluids

Annular injection is sometimes used for the disposal produced waters and drilling muds. Improper casing cementing, damaged casing, or aquifer plugging can result in migration of fluids to usable aquifers.

Migration of Tank and Pit Wastes

While the reserve or mud pit is often closed soon after the outset of production, other waste sumps may remain in use for the life of the operation. Typically, the largest part of reserve pit contents is muds and cuttings, but nearly any other wastes may be present in pits (including produced water, emulsions, oily debris, etc.). Seepage or failure of reserve pit walls, and/or the absence of pit liners may allow the migration of fluids to ground water of and surface water. Constituents of concern include chlorides, metals, and hydrocarbons. Commingling of wastes in reserve pits or tanks may increase the potential impacts to ground water. The disposal of separator sludges, untreatable emulsions, tank bottoms, and other separator and treatment wastes along with produced water in a produced water pit increases the range of constituents which may migrate to ground water in the event of a release.

Migration of Sweetening Wastes

If the lease requires gas sweetening treatment, the possibility exists for the migration of stored sweetening wastes to ground water and (surface water). The sweetening process may generate elemental sulfur, spent iron sponge, other amine compounds, and glycol compounds in its waste stream. Commingling of these wastes with produced water or other liquid wastes in pits may increase the potential for impact to ground water.

Vertical Migration from Surface Treatment Sites

Excess drilling fluids and produced waters may be disposed via various surface treatments, such as road spreading, land farming, and evaporation. Runoff in areas where road spreading of saline waters is practiced may allow the seepage of chlorides to shallow aquifers. Similarly, evaporation facilities may allow the vertical migration of saline waters to shallow ground waters. Finally, landfarming of wastes (the surface spreading and tilling of liquid and solid wastes such as produced waters and drilling fluids) may allow the seepage of chlorides and oily wastes to shallow ground waters.

Site Closure

In this section site closure will include only those potential impacts from activities not covered elsewhere. For instance, burial of drilling muds is covered under waste management, though this activity may occur as part of final closure operations.

Vertical Migration of Closed Pit Contents to Ground Water

During site closure, on site pits may be backfilled with soil for permanent disposal. Failure to dewater pit contents and/or grade the covering soil to minimize infiltration of rain water may result in downward migration of contaminants to shallow aquifers. Constituents of concern include chlorides, hydrocarbons, metals, NORM, and other oil field waste materials.

POTENTIAL IMPACTS ON SURFACE WATER

Surface water occurs in lakes, streams, rivers, wetlands, etc. and may support a plethora of wildlife and vegetation. In addition, many land uses are dependant on surface water including grazing, forestry, and recreation. Surface water and ground water exist in a dynamic system where surface water may discharge to ground water, replenishing surficial aquifers; ground water may also discharge to surface water, keeping surface water flowing even in times of little or no precipitation. Typical impacts to surface water include heavy loads of total suspended or dissolved solids (often associated with runoff) and contamination with salts, toxics or bacteria. Fish and other in-stream species (flora and fauna) may be especially sensitive to specific toxics (See Ambient Water Quality Criteria in Table 1).

Identified below are potential impacts to surface water associated with oil and gas operations. These impacts represent pathways for surface water contamination with possible subsequent impacts to human health and the environment. It is again emphasized that site-specific factors (e.g., activities, environmental setting, etc.) determine potential and actual impacts at individual sites.

Exploration and Development

Site Runoff to Surface Waters

Road construction may cause erosion and transport of soil and sediments to surface water, resulting in high suspended solids and more rapid sedimentation. In addition, reserve and mud pit seepage and overtopping may result in migration of contaminants to surface waters. Similarly, once drilling activities have begun at the site, oily wastes and miscellaneous chemicals (mud additives, diesel oil, lubrication oil, rigwash, etc.) may accumulate in soils. Seepage or failure of onsite storage tanks may add to the deposition of wastes. Surface runoff may transport such wastes to surface waters, potentially impacting aquatic populations and degrading surface water quality. Potential impacts depend on the contents of the pits, but waste constituents of concern include drill cuttings and other solids, mud additives, brine, NORM, oily wastes, and metals.

Production

Migration of Product Stock Tank Leaks

Oil and gas stocks may be stored in surface or underground tanks prior to delivery. Leakage from storage tanks may result in migration of contaminants to surface waters directly or through runoff from contaminated soils. The extent of potential impacts depends on the constituents, extent and duration of any release.

Migration of Gathering Line Leaks

Product pumped to the surface from one or many wells on a lease must be collected in gathering lines leading to treatment and storage facilities. Chronic leaks or failure of gathering lines may result in migration of oil to surface receiving waters directly or through runoff from contaminated soils. Constituents of concern include hydrocarbons and aromatic hydrocarbons.

Vertical Migration of Injection Fluids

The injection of water into producing formations for secondary recovery may result in the unintended migration of water by way of abandoned or improperly plugged wells in the area. Salt water breakout (surface appearance of downhole waters) may occur, with the possibility of migration to surface waters. This potential may be amplified during tertiary recovery with the higher pressures accompanying steam drive production. Constituents of concern include chlorides, injection fluid additives, and hydrocarbons.

Waste Management

Surface Water Discharges of Produced Water

The production of formation water along with oil and gas is common to all phases of production, and may begin as early as the first day of production. Typically the largest volume waste stream associated with oil and gas production, produced water requires significant surface storage and treatment capacity prior to disposal by any number of means. Direct surface water discharge, pit or tank seepage or failure, or runoff from surface evaporation facilities all present the potential for impacts to surface waters. Constituents of concern include residual oily materials, metals, chlorides, and NORM.

Migration of Commingled Wastes

Commingling of wastes in pits or tanks may increase the potential impacts to surface water. The disposal of separator sludges, untreatable emulsions, tank bottoms, and other separator and treatment wastes along with produced water in the reserve pit may mobilize these wastes and increase the range of constituents that may migrate to surface water in the event of a release.

Runoff from Surface Treatment Sites

Excess drilling fluids and produced waters may be disposed via various surface treatments, such as road spreading, land farming, and evaporation. Runoff in areas where road spreading of saline waters is practiced may allow the migration of chlorides to surface waters. Similarly, runoff from evaporation facilities may allow the migration of saline waters to surface waters. Finally, landfarming of wastes (the surface spreading and tilling of liquid and solid wastes such as produced water and drilling fluids) may allow the surface migration of chlorides and oily wastes to surface waters.

Migration of Sweetening Wastes

If the lease requires gas sweetening treatment, the possibility exists for the migration of stored sweetening wastes to surface water. The sweetening process may generate elemental sulfur, spent iron sponge, other amine compounds, and glycol compounds in its waste stream. Commingling of these wastes with produced water or other liquid wastes in pits may increase the potential for impact to surface water.

Site Closure

In this section, site closure includes only those potential impacts from activities not covered elsewhere. For instance, burial of drilling muds is covered under waste management, though this activity may occur as part of final closure operations.

Sedimentation of Surface Waters

Failure to regrade and revegetate abandoned oil field sites may allow runoff and erosion to transport soils to surface waters. In addition, this erosion can increase the risk of surface water contamination from other sources (e.g., closed disposal sites, contaminated soil, etc.).

POTENTIAL IMPACTS ON SOIL

Typical impacts to soils associated with oil and gas operation are identified below and include compaction (and damage of the root zone of surficial soils), erosion and loss of soils (due to loss of vegetation and runoff), and contamination with organics (e.g., hydrocarbons, etc.) and inorganics (salts and sulfur), resulting in toxicity to plants and contaminated runoff. It is again emphasized that site-specific factors (e.g., activities, environmental setting, etc.) determine potential and actual impacts at individual sites.

Exploration and Development

Compaction and Erosion from Road Building

Typically, unimproved roads are constructed to access areas during exploration and to transport the rig and other equipment for drilling and development. Land disturbance such as leveling areas for roads may result in soil erosion and subsequent travel on these roads may compact the remaining soils such that soil productivity is decreased. Root zones can become damaged and may not support native vegetation. In addition, repeated travel along an area without constructed roads may result in similar compaction and damage to vegetation. Removal of or damage to vegetation and soil may result in increased runoff and further erosion.

Site Runoff

Site runoff from storm events presents the possibility of transporting pit contents and uncontained wastes offsite, with the resulting impacts to soils. Constituents of concern include oily wastes, drilling muds, and salts. If drilling encounters salt domes or other high salt content formations, the contents of the pits may contain high salt concentrations, increasing the potential damages to soils.

Production

Compaction and Erosion During Production

The initiation of production requires additional site preparation, from development drilling to installation of gathering facilities and road construction for transportation of product. In general, such site preparations may directly impact site and area soils, as well as increase the area of potential impacts. Further, the increased use of roads consistent with product and waste transportation may result in greater compaction of soils on and near roads.

Product Stock Tank Leaks

Oil and gas stocks may be stored in surface or underground tanks prior to delivery. Leakage from storage tanks may result in migration to area soils. The extent of potential impacts depends on the extent and duration of any release.

Gathering Line Leaks

Product pumped to the surface from one or many wells on a lease must be collected in gathering lines leading to treatment and storage facilities. Chronic leaks or failure of gathering lines may result in impacts to soil both onsite and beyond site boundaries. Constituents of concern include hydrocarbons and aromatic hydrocarbons.

Injection Fluids and Saltwater Breakout

The injection of water into producing formations for secondary recovery may result in the unintended migration of water to area abandoned or improperly plugged wells in the area. Salt water breakout (surface appearance of downhole waters) may occur, with the possibility of damage to affected soils

This potential may be amplified during tertiary recovery with the higher pressures accompanying steam drive production. Constituents of concern include chlorides, injection fluid additives, and hydrocarbons.

Waste Management

Pit Excavation, Overtopping and Seepage

As previously discussed, drilling activities require the maintenance of onsite drilling mud and reserve pits for the storage and temporary disposal of muds and drilling wastes. Excavation of these pits has a direct impact on soils through land disturbance. If top soils are not segregated from underlying material during excavation, their productivity and effectiveness in reclamation may be lost. In addition, absence of or damage to pit liners may allow seepage of fluids to underlying soils. Similarly, pit wall seepage or failure, and overtopping may allow seepage of wastes into surface soil both onsite and beyond site boundaries. The extent of potential impacts depends on pit fluid constituents and the volume of any releases. Note that brine contamination of soils may lead to soil sterilization. Other impacts to soil may result from ground deposition of rigwash and other oil field wastes, and storage tank leakage or failure.

Sweetening Wastes

If the lease requires gas sweetening, the possibility exists for contamination of soils with stored sweetening wastes. The sweetening process may generate elemental sulfur, spent iron sponge, other amine compounds, and glycol compounds in its waste stream. Commingling of these wastes with produced water or other liquid wastes in pits may increase the potential for impact to soils. Historically, sulphur discharged from sweeteners was often released directly to the ground, forming a storage pad for subsequent releases of sulphur. Water running off the storage area was highly acidic and damaging to soils. Such practices may still be in use.

Onsite Burial of Pit Wastes

Shallow burial of drilling wastes and other pit wastes accumulated during production can result in the vertical migration of salts and hydrocarbons to top soils, resulting in damages to plants and loss of soil productivity.

Landfarming of Pit Wastes

Landfarming of pit wastes, (tilling of sludges and solids into soils), may result in long term damages to soil productivity if the wastes are high in total dissolved salts, especially sodium chloride, or contain oil and grease in significant amounts, or if the natural capacity of the soil to degrade wastes is exceeded. Sensitivity to salts and hydrocarbons varies with soil type and plant type. However, damages may result with electrical conductivity and oil and grease concentrations as low as 4 mmhos cm and 2 mg/l, respectively.

Evaporation of Produced Water

Evaporation of produced water on land may result in accumulation of salt contamination in affected soils. Significant salt concentrations can reduce productivity of soils for many years.

Site Closure

In this section site closure will include only those potential impacts from activities not covered elsewhere. For instance, burial of drilling muds is covered under waste management, though this activity may occur as part of final closure operations.

Sedimentation of Surface Waters from Site Runoff

Failure to regrade and revegetate abandoned oil field sites may promote erosion of surface soils. These soils, by virtue of the site's use, may contain wastes and constituents (e.g. oily debris, hydrocarbons, metals, etc.) that have the potential to migrate to beyond site boundaries, resulting in contamination.

POTENTIAL IMPACTS ON AIR

Impacts to air include release of both toxic and nontoxic pollutants during oil and gas drilling, production and waste management. Toxic gases that occur in the producing formations, especially hydrogen sulfide and poly-aromatic hydrocarbons, may be emitted from active operations. In addition, conventional air pollutants, such as particulates, ozone, carbon monoxide, etc., associated with diesel engines that power the operation are released.

Identified below are potential impacts to air associated with oil and gas operations. These impacts represent pathways for air contamination with possible subsequent impacts caused by deposition of pollutants to soil, in addition to impacts on human health and the environment. It is again emphasized that site-specific factors (e.g., activities, environmental setting, etc.) determine potential and actual impacts at individual sites.

Exploration and Development Drilling

Hydrogen Sulfide Emissions from Active Operations

In some areas of the U.S., hydrogen sulfide occurs as a natural contaminant in oil and gas producing formations. Uncontrolled releases during drilling may threaten human health. Typically, drill rigs are evacuated when hydrogen sulfide is detected in ambient air near the rig.

Fugitive Dust Emissions

Road construction, site clearing, transportation on dirt roads during exploration to and from the well site, and onsite mixing of muds generate fugitive dust.

Machinery Exhaust Emissions

Operation of heavy machinery during site preparation as well as running the rig, the return mud shakers, and other machinery during drilling operations will be accompanied by the emission of fossil fuel combustion exhausts always associated with such equipment. Such exhausts will include oxides of nitrogen, oxides of sulfur, ozone, carbon monoxide, and particulates.

Production

Emissions from Gas Flaring

Some oil leases may co-produce natural gas at rates below what is economical to collect for sale. If no other use for the gas is found, such gas may be flared (burned in the air) for disposal. Flaring of gas will result in the release of carbon monoxide, nitrogen oxides, and, if the gas is sour, sulfur dioxide. Additional emissions may include products on incomplete combustion.

Volatilization of Petroleum Fractions

Crude oil generally contains some fractions that will volatilize at ambient temperatures and pressures. Storage of crude in open tanks as well the accumulation of waste oil and grease in reserve pits may allow the release of volatile organic compounds (VOCs) to the air. Further, fugitive leaks from pipes, closed tanks, and treatment equipment may contribute to the release of VOCs to the air. Such releases may be of particular concern in areas that are not in attainment of ambient air standards for ozone.

Release of Hydrogen Sulfide from Sour Gas

Hydrogen sulfide, with its inherent toxic effects, may be released from sour gas plants. Impacts would be localized and dependent on concentration in ambient air.

Machinery Exhaust Emissions

Operation of production equipment such as pumps, separator motors, heater treaters, generators, and boilers may result in the release of fossil fuel combustion emissions. Such exhausts will include oxides of nitrogen, oxides of sulfur, ozone, carbon monoxide, and particulates. Typical industry practice is to utilize fuel sources produced on site, such that machinery exhausts may contain grater amounts of particulates than from refined fuels. Additional emissions may include products of incomplete combustion.

Waste Management

Volatilization During Evaporation and Landfarming

By design, evaporation pits for produced water or other wastes release water and VOCs to the air. This also may occur during spraying or otherwise applying produced water or other wastes to the soil for landfarming or road spreading.

POTENTIAL IMPACTS ON ECOSYSTEMS

This section is organized differently from previous sections. First, it provides a summary of abiotic and biotic parameters and how they relate to ecosystems. Following this, two subsections discuss the impacts on terrestial ecosystems, and on aquatic ecosystems. Because environmental impacts resulting from oil and gas exploration or development activities are often localized in nature, mitigation of these impacts can best be accomplished by careful siting of the facilities within the ecosystem, and by minimizing the extent of the area impacted. Siting decisions should include consideration of the presence of sensitive areas such as rare habitats, sensitive species, waterbodies, and so on. Where disruptions due to oil and gas activities are unavoidable, all efforts should be made to limit damages through minimizing the area that will be disturbed, and by timing activities to avoid disturbing plants and animals during crucial seasons in their life cycle. This could mean temporarily halting or delaying activities to avoid disturbance to animals during migrations or breeding seasons.

An EIS or EA should address potential impacts on a number of biotic and abiotic characteristics of habitats. These characteristics define the nature of the environment, and in some ways, also define the sensitivity of the environment to man-made stress. Without a basic understanding of the ranges of these characteristics and how they vary by season, it will be nearly impossible to determine whether the most important impacts have been identified or not. Even when these characteristics are discussed thoroughly, however, it may be necessary to contact local ecological experts to determine whether the changes in characteristics associated with exploration or drilling are likely to be significant or minor. Experts can generally be found through contact with local universities, or state universities in nearby locations.

Abiotic Ecosystem Parameters

Abiotic parameters that are important determinants of terrestrial ecosystem type and function. These include the temperature regime and climate, water regime and rainfall, topography, soils, nutrients, and light. Some of the most important abiotic parameters in aquatic ecosystems are size of water body, water flow and flushing, temperature, salinity, and nutrient availability. Each of these parameters is discussed below.

Temperature

The ability to withstand temperature extremes varies widely among animals and plants. Because the optimum temperature for completion of several stages of the life cycle of many organisms varies, temperature and climate impose a restriction on the distribution of species. Generally, the range of many species is limited by the lowest or highest temperature in the most vulnerable stage of its life cycle, usually the reproductive stage.

Water

The means of obtaining and conserving water shape the nature of terrestrial communities. In a practical sense it is difficult to separate a discussion of water from the discussion of temperature or climate because organisms use water for temperature control.

Moisture relationships within an ecosystem are often closely associated with the distribution of rainfall. Because of this, seasonal distribution of rainfall is generally more important than average annual precipitation. For example, organisms do not usually face water stress in a region receiving 50 inches of rainfall spread over the year, but the same rainfall falling over only a few months results in extended periods of drought that may be difficult to survive.

Water is often a limiting factor in defining a habitat. Moisture, or lack of it, influences the distribution of plants on a geographic or local basis. Alteration in the water regime thus may be detrimental to existing populations.

Humidity, water in the air, affects the rate at which water is lost by plants and by soils. Humidity varies with ground-cover and with topography. Relative humidity is generally greater under a forest canopy than on the outside during the day, and the daily range of humidity is greatest in valleys, decreasing with altitude. Local humidity regimes can be altered by the removal of ground-cover, resulting in a pronounced effect on the composition of plant species in nearby areas.

Nutrients

Living organisms require at least 30 to 40 elements for their growth and development. Macro and micronutrients are necessary for plant and animal life. These include calcium, magnesium, phosphorus, potassium, sulfur, sodium, chorine, and trace elements such as copper, zinc, boron, manganese, molybdenum, cobalt, vanadium, and iron. Plants are able to obtain these nutrients directly from the soil. Animals are all ultimately dependent on plant life for their nutrients.

Each plant species has a requirement for a specific quantity of essential elements, and each species is able to exploit the nutrient supply in a manner that may not be duplicated by other species. This enables different plants growing in the same environment to exploit slightly different nutrient sources. For example, shallow rooted species may use the nutrient supply on the upper soil surface, while those with deep tap-roots may draw on deeper supplies of nutrients. Some species are successful in nutrient poor soil, but are less able to compete against other species on richer soils. Therefore, nutrient levels in soil have a pronounced influence on the local distribution of plants.

Soil acidity influences the uptake of nutrients by plants, and therefore has a strong influence on plant distribution. Plants that are tolerant to acid conditions are generally more tolerant to metal ions than plants that are adapted to high pH levels.

Because all animals depend directly or indirectly on plants for food, the quantity and quality of plants can affect the well being of the animals. Where quantities are insufficient, animals may suffer from malnutrition, starvation, or leave the area. Where the quality of the food is insufficient, reproductive ability/success, health and longevity of the animals may be impacted.

In aquatic ecosystems, nutrients are generally introduced from land. Plants growing on river banks or on shore retain nutrient-rich soil and absorb nutrients. The placement of an oil and gas facility may require the removal of vegetation, and can increase the nutrient load to a water body, increasing the probability of eutrophication.

Topography

As discussed above, topography influences the temperature regime and moisture regime of an area, and therefore can be a determinant of plant communities and distribution. In dry areas, small-scale changes in topography must be considered in siting an oil and gas facility. Low-lying areas may be subject to flooding and may accumulate runoff and sustain plant and animal communities that are not found in the surrounding areas.

Soils

Soils are formed from organic and inorganic materials and generally have a clearly defined structure. This structure is a layering of materials of various characteristics, with each layer varying in thickness within certain ranges. Plant communities are dependent on particular soil structures and other factors such as grain size, pH, and nutrient content. Removal of ground-cover may result in soil erosion, removing the surface soil layer, resulting in and changes in plant communities. Mitigating measures must be determined prior to any removal of existing soils and vegetation to limit the area affected by erosion.

Light

Light is important in the biological function of plants. Light energy is used by plants for photosynthesis. Some species require more light than others, and the amount of light or shading has a great impact on the reproductive stages of plants. Some plants require large amounts of sunlight to flower or to germinate. Others are less tolerant to bright sunlight and can only germinate in the shade. Therefore, the removal of ground-cover may prevent some species from reproducing or germinating, and open an area to less desirable, opportunistic species.

Flushing of Aquatic Ecosystems

Freshwater aquatic ecosystems may range from seasonal ponds and streams to rivers and lakes. Saltwater systems include estuaries, coastal areas and oceans. The rate at which water moves through those systems determines, to some extent, their ability to withstand discharges without serious effects. In rivers and streams the flow of a water body can be characterized as a mean flow, x year low flow, and x year high flow. Lakes and ponds can be characterized by the water turnover rate, the rate at which water gets replaced. Extreme flows in streams (that are 3 orders of magnitude or more above mean flows), indicate a propensity for flooding, and can be an important factor to consider in siting a facility.

Salinity

The distribution of aquatic biota is influenced by the salinity of water bodies. Freshwater organisms are generally sensitive to increases in salinity, and this is important when determining whether produced waters should be discharged or re-injected. Even in more saline areas, discharge of saline produced waters is important because transitions between fresh water and the sea consist of brackish waters containing unique species assemblages that require specific salinity regimes for their survival.

Turbidity and Suspended Sediments

Increases in turbidity can occur in an aquatic ecosystem as a result of a discharge, increase in soil erosion, or through the resuspension of sediments. Increased turbidity can adversely impact photosynthesis in aquatic systems by decreasing the light available to phytoplankton. Furthermore, because turbidity is caused by suspended particles, it can interfere with feeding efficiency of filter feeders. Finally, as the suspended sediment settles, it can smother existing bottom vegetation and alter flow regimes.

Biotic Ecosystem Parameters

Biotic ecosystem parameters provide an indication of the health of the ecosystem, and information on the possible impacts of oil and gas operations on individual species or communities. Biotic parameters that should be considered in an EIS or EA include rare and endangered species, and dominant species, along with their relative populations sizes and habitats.

Rare and Endangered Species

Every EIS or EA should consider impacts on rare or endangered species. Generally, a list of such species alone is inadequate to evaluate potential impacts. Information is also needed on the size of the population, and to the extent possible, on their preferred habitats, and the local distribution of that habitat. Locally rare species are sometimes common in other areas of the country, but adverse impacts of oil and gas operations on populations of such species should not be discounted.

Dominant or Important Species

Certain species can be considered dominant because of their large populations, while others are dominant because they exert control beyond their numbers through their voraciousness or specialized niche (food and/or shelter requirements). Dominant species can only be determined with a knowledge of the local ecosystem. It may be necessary to consult with a local expert (e.g. member of the ecology, botany, or zoology department of a local university or college, state fish and wildlife service, etc.). Typically, EISs or EAs generally do not have information on the dominant species, but may identify certain commercially or recreationally important species. Such designations generally have no bearing on the ecological importance of these species. As with rare and endangered species, lists of important or local species alone are inadequate to evaluate the potential impacts of oil and gas activities on their populations.

Habitat

Each habitat, or place where a species lives, is defined by an assemblage of biotic and abiotic factors. A habitat is by no means limited to a particular species, although some species have more specific habitat requirements than others. While some habitat types are common in some areas of the country, the locally rare habitats are typically more at risk. Some species require a minimum area of suitable habitat in order to maintain their population sizes, and any decrease in that area will result in decreases in numbers.

Terrestial Ecosystems

Generally, environmental impacts of oil and gas exploration or production can be tied to one of three environmental changes: the release of toxic (or foreign) chemicals to the environment: the removal of native vegetation to make room for drilling rigs, treatment facilities, or pits; or the modification of the surface topography or soil structure in ways that modify surface and subsurface water flows or indirectly modify the vegetation or animals that can be supported by an area. These are discussed below.

Environmental Release of Toxic Chemicals

A great deal is known about the effects that individual toxic chemicals can have on individual organisms or groups of organisms. Various toxicity tests are designed to measure the concentration of toxicants in soils, water, or air that could have deleterious effects on a number of species of plants and animals. Test results, expressed in terms of EC_{50} or LC_{50}, indicate the concentration at which 50 percent of the organisms demonstrate an effect (EC_{50}) or die (LC_{50}) because of exposure to a chemical. These data provide rough guidelines as to the safe environmental concentrations of various chemicals. As a rule of thumb, divide the EC_{50} or LC_{50} by 100 to determine a safe concentration. The factor of 100 is necessary to account for the many factors that are not measured in toxicity tests such as extreme temperatures, exposure to more than one toxic chemical, or low availability of habitat. If there are species that would be exposed to concentrations approaching an EC_{50} or LC_{50} as the result of releases of toxic chemicals, then those species will be severely impacted at the site.

Generally, the effects of toxic substances are isolated to areas near spills. This is particularly true for substances such as heavy metals (copper, lead, zinc, etc.), and some of the heavier hydrocarbons (e.g., tars, etc.). For volatile organic compounds and those that are soluble in water, the point of release can be some distance from the site of potential impact. Communities downslope, downgradient, or downwind from the release point should be identified to ensure releases have minimal impact or, especially if sensitive communities or locally rare habitats are present, that suitable precautions are taken against accidental releases.

Downslope, downgradient and downwind communities are targeted because the scale of toxic contamination is often site-specific, isolated to within a few hundred yards of a rig or reserve pit. Thus, it may be necessary to know where rigs and pits are to be located in order to understand their relationship to surrounding habitats. Generally, in order to adequately assess environmental impacts, it is necessary to know specifically where drilling is likely to occur. Sites of potential releases can thus be placed where the effects of any potential releases are minimized.

Environmental Release of Other Chemicals

A limited subset of chemicals is considered toxic by EPA at concentrations found in the environment. Toxic chemicals include a variety of materials found in crude oil or drilling fluids, and include metals such as chromium and zinc and various forms of hydrocarbons including PAHs (PNAs). Organic chemicals, however, are generally of concern more because of their potential carcinogenic (cancer producing) characteristics than because of their direct toxicity. There are a whole range of compounds that are integral to oil and gas exploration and production that are not generally considered toxic to flora or fauna but may cause extensive environmental impacts. Also some relatively non-toxic chemicals may be transformed into more toxic forms through interaction with bacteria, or through environmental degradation (e.g. hydrolysis, photolysis). Crude oil, many of the components of crude oil, and saline water are three types of materials that are not generally considered toxins but kill plants, mainly through altering their ability to take up and hold water.

Because of the significance of the saline wastes that comprise most produced water, they should receive special attention. In oil and gas production, produced water has a greater volume and potential for mobility than do sediments. Some constituents associated with sediments (heavy metals, hydrocarbons) might migrate depending on factors such as the pH of the soil, eH, porosity, and water saturation. Saline waters readily percolate through soils, and can cause extensive contamination of natural areas around reserve pits when sufficient precautions are not taken to prevent their release. Trees and shrubs (and most other terrestrial vegetation) are readily killed by contact with soil or water that has a high salt content. The killing of vegetation around a facility by elevated salt levels in the soil and the subsequent leaching of saline wastes through rainfall runoff lead to a wider area of vegetation loss than caused by direct clearing. The greater the loss of vegetation, the greater the potential for damage to other resident species that rely on the vegetation of a particular habitat (e.g. woodland, meadow) for food or shelter.

Physical Disturbance - Woodlands

Loss of Habitat Structure. Many of the characteristics of ecosystems are defined and preserved by their structure. Forests and woodlands are characterized, for example, by varying amounts of above-ground structure comprising the limbs and leaves (needles) of the dominant trees, perhaps including an understory of different species. It is this vertical structure that provides appropriate habitat for different species of birds and other wildlife, and there is a large group of invertebrate species that typically inhabit the woodland canopy or the litter on the woodland floor. Removal of this structure has ramifications for many plant and animal species, not just those obviously present. For example, wildflowers that grow up annually from seeds, and that may provide food for wildlife, may not grow if the woodland canopy is removed.

Removal of trees and associated understory has several effects. First, removal of trees allows more sunlight to reach the ground. This alters the temperature regime of the litter layer, causing higher temperatures to be reached during the day, and possibly lower temperatures to be reached at night. The increase in range of temperatures may not be suitable for the extant flora and fauna of the forest floor, and therefore the native organisms may be replaced by opportunistic "nuisance" species, or the total amount of living matter on the forest floor may be reduced. For small areas, such changes may have minimal significancy (there are exceptions, see below), but with increasing removal of trees and shrubs, changes become more extreme and can affect more than just the area where the trees were removed. However, limiting disturbance to small areas does not always work to limit impacts, as disturbance to many small areas may result in a large cumulative impact.

Loss of Minimum Habitat Areas. Most wildlife species prefer some minimum size of a specific habitat type (or habitat types). Without a minimum area of habitat, they either cannot find sufficient food to feed themselves and their offspring, cannot find nesting sites sufficiently distant from other individuals of the same species, or cannot find sufficient protection from predators. Also, specialized habitats are sometimes required in certain areas to provide resting locations for migrating birds or animals. Thus, reducing the amount of habitat in a give area must be given careful consideration. One of the most damaging activities is the fragmentation of a limited habitat into two or more parts. Contiguous habitat can be divided by clearing a large area in its center for rigs, treatment facilities, or reserve pits or by building a road through it (for small areas). By dividing an area of habitat into two pieces, it is possible to cause effects that are out of proportion to the amount of land being cleared. If, for example, an area supporting six pairs of a species is divided into two areas of equal size by a road that removes only 1% of the area, only four pairs might be able to survive in the remaining area, depending on its shape. Because of the possibility of creating greater disturbances by dividing up habitats, it is generally better to place facilities and roads at some distance from, or along the edges of habitats that are locally limited in distribution.

Changes in Runoff. Trees and shrubs intercept rainfall, slowing the rate at which it hits the ground and providing a ground-level environment that reduces the rate of surface runoff. Rain hitting a woodland is much more likely to be retained at the site and be incorporated into plants and animals than rain hitting a cleared woodland. This has several benefits: first, the propensity for flooding in downstream areas is maintained at a low level; second, erosion of soils necessary to support plant growth is minimized; and third, nearby streams, lakes, and ponds are protected from high loads of sediments and nutrients that can cause permanent changes in their flora and fauna.

Physical Disturbance - Grasslands and Scrublands

Grasslands and scrublands are dominant ecosystems in various parts of the country primarily based on the amount of rainfall they receive. Grasslands typically dominate with rainfall of about 20 inches per year (depending of the seasonality of precipitation), and scrublands (deserts) dominate with less than 10 inches of rainfall per year. In both of these ecosystem types, water plays a key role in determining not only the type of vegetation that occurs, but the kinds and abundance of animals as well.

Grasslands and scrublands have structures similar to those of woodlands, but the scale of the structures is smaller. Both of these types of ecosystems are generally "patchy" in distribution, and isolated patches of locally rare habitats may significantly affect the viability of locally rare, threatened, or endangered species. Thus, the location of exploratory wells and the relationships among the various supporting facilities around exploratory wells can make significant differences in the environmental effects realized by exploration and production.

While the scale of the patchiness of grasslands and scrublands varies (patchiness has been observed on several different scales, from grids of a few square meters to grids of hectares), the scale of significance with exploratory drilling is on the order of an acre, and with production facilities, several acres. To avoid unnecessary disturbance of existing habitats, mitigating measures should be identified in environmental documentation. These measures should be implemented so that decisions to locate drilling or processing facilities take account of the identity of the types of vegetation at potential sites, and the determination of whether this vegetation is relatively abundant or relatively rare in nearby areas. If the species are relatively rare, alternative sites should be chosen in order to preserve the existing large-scale structure of the ecosystem as much as possible.

In general terms, rigs and other facilities should not be located at the lowest point of land in the area (this is a place where water is likely to accumulate, and thus have unique local importance), at the lowest point of a swale or gully (for the same reason), or on significant slopes (unless necessary). Placing structures (rigs, reserve pits, etc.) on slopes where they can interrupt the flow of water over the land surface can sometimes have unexpected effects. Some localized habitats rely on water being provided by overland sheet flow, flow in channels that are indistinct (small or shallow and broad) and are not normally noticed. In drier areas, such overland flow during rain storms may provide critical water to low-lying land in sufficient amounts to nourish more diverse habitats and sustain more diverse communities in an environment that is normally considered to be inhospitable to them.

Physical Disturbance - Tundra

The Arctic tundra is a treeless plain characterized by extremely cold temperatures, a short growing season, and low precipitation. In Alaska, lowland tundra covers large portions of the Aleutian Islands, the delta of the Yukon and Kushokwim Rivers, the Seward Peninsula, and the North Slope. Much of the current oil and gas development is occurring in the North Slope region. The North Slope encompasses approximately 200,000 km^2 and is comprised of three major areas: the Brooks Range, the Arctic Foothills, and the Arctic Coastal Plain. The climate consists of long, dry, cold winters, and short, moist, cool summers. Air temperature is well below freezing for nine months of the year. Little precipitation falls in the area (10-20 cm) annually, and almost 40 percent occurs as rain during the summer.

Arctic tundra is unique because its shallow soil is underlain by a permanently frozen layer (permafrost), sometimes to depths up to 600 m, that is impenetrable to water or roots. Since the permafrost is impervious to water, it forces all water to move above it, saturating the soil, and creating thousands of shallow lakes and bogs in the arctic coastal plain. These saturated soils in combination with the cool summer temperatures greatly reduce the rate of microbial decomposition of organic material. Therefore, the soils of the tundra are generally poor because they lack an abundance of nutrients essential for plant growth.

Although the arctic permafrost remains frozen year round, the active, top layer (anywhere from a few centimeters to a meter) thaws during the summer. In this shallow layer of poor soil, only the few species capable of adapting to the rigors of extremely cold temperatures, long winters and a short growing season thrive. Not surprisingly, most of the tundra's vegetation is structurally simple. The major vegetation types consist primarily of shrubs, grasses, and sedges. Lichens and mosses are also important elements of the tundra habitat. The terrestrial mammal fauna of the North Slope is limited to approximately 24 species. Barren-ground caribou are the most characteristic mammals, however, moose, wolverines, and grizzly and polar bears are other significant wildlife populations. Over 40 species of birds nest regularly in the tundra.

The physical fragility of tundra vegetation is a primary reason for concern about development in the Arctic. Any removal or disturbance of tundra vegetation can destroy its insulation properties, causing thermal erosion of the permafrost. The vegetation of the tundra shades the permafrost, which reduces the heating of the soil, and protects the permafrost from melting. Once the permafrost melts, it is more susceptible to physical damage. In addition, due to the climatic and physical conditions of the tundra, any revegetation of degraded areas occurs very slowly. Evidence of minor physical disturbances can exist for decades.

The primary effects of oil and gas development on tundra are terrain damage or modification, and physical disturbance of wildlife. This can occur in the vicinity of seismic lines, drilling sites, camps, landing strips, production sites, and road or pipeline construction routes. To protect the permafrost, it should be insulated from oil and gas exploration and production facilities, including structures such as buildings and roads. This insulation is provided primarily by gravel pads placed underneath facilities. Gravel pads can provide a stable insulating surface for facilities and reduce the destruction of vegetation, and hence the permafrost. Of course, any reduction in the size of the facility can reduce its direct impacts on the habitat as well.

Tundra ponds in contact with discharges from oil and gas reserve fluid pits have been found to contain significant concentrations of organic and inorganic compounds. And reduced water quality in not the only environmental problems associated with reserve pit fluids. These fluids are discharged to control dust on roads. However, the pollutants in the fluids have the potential to leach from the road to surrounding tundra wetlands.

Oil and gas development activities also may affect wildlife by altering habitat, impeding or deflecting migrating mammals, birds and fishes, and disturbing ungulate calving areas. For example, while gravel pads reduce the degradation of permafrost, they can also cause other habitat impacts. Roads and pads can act like dams and create artificial impoundments that restrict runoff. As a result, flooding can be a major problem. Impoundments may change habitat by retaining water that replaces the tundra, and this can cover critical nesting habitat for tundra birds. Also, fish passage can be obstructed when road culverts are improperly placed and reduce stream flow. In addition, oil and gas development may affect not only the immediate facility, but also the the area surrounding it. Oil fields encompass large areas that include facilities connected by extensive infrastucture. Some sensitive species such as birds and caribou cows with calves tend to avoid these developed regions containing roads and pipelines. So the amount of habitat disturbed by oil development is much larger than the area actually covered by facilities.

Other Disturbances

Physical modification pose the greatest threat to ecosystems, but increased human activity resulting from oil and gas operations can be equally disruptive to wildlife. Human activity may cause wildlife to move out of an area or relocate in less desirable habitats. The effects of human activity can be *mitigated by judicious timing of activities to avoid sensitive stages in the animal's life cycle* (e.g., migration or reproduction).

Aquatic Ecosystems

Unlike terrestrial ecosystems, where the primary effects of oil and gas exploration and production are realized through physical disturbances or changing water relationships, the effects in the aquatic environment are related primarily to chemical and physical alterations caused by waste disposal. The plan for disposal of drilling muds and cuttings and produced water determines potential effects (barring accidents or spills caused by inadequate implementation of the disposal procedures).

When evaluating the effects on aquatic habitats, it is important to remember that aquatic environments include flowing bodies of water such as rivers, streams, and estuaries and relatively quiescent water bodies such as lakes, swamps, marshes, and ponds. In general terms, the potential for environmental damage is related to the amount of water flowing through a system, and shallow, slow-flowing systems, such as wetlands (marshes, swamps), are generally more sensitive to discharges and physical disruption than other systems. Seasonal wetlands are particularly vulnerable to physical disruption because their location is often not identified until the "wet" season, after the environment has been disturbed. Since wetlands provide a unique habitat for wildlife and are among the most productive of the aquatic environments, their identification and location should be of primary importance in discussions of environmental effects.

Discharges to Open Waters and Wetlands

A state may require that drilling muds and cuttings be contained in land-based facilities adjacent to the body of water in which drilling is occurring. This is generally the preferred alternative for the following reasons.

Drilling Muds and Cuttings. First, when drilling muds and cuttings are discharged directly into water bodies, the turbidity of the water is increased, reducing the amount of light that can penetrate through the water, and thus reducing the amount of plant production that occurs. This essentially reduces the ability of the aquatic ecosystem to produce biomass and support a diverse and abundant flora and fauna. Second, the nature of the drilling muds and cuttings is often substantially different from the nature of the sediments at the drill site. Since most plants and animals inhabit sediments with a limited range in grain sizes, changing the grain size of sediments around the drilling rig will cause the local removal or replacement of native species with other species. While in some cases, species replacement may have little effect, it is not usually possible to predict the species that would colonize the new sediments, and thus it would be difficult to determine whether there would be significant influence on rare, threatened, or endangered species in the area.

A third effect of the discharge of the drilling muds and cuttings into receiving waters is the potential for the alteration of water flow. In marine environments, the muds form a barrier to water passage (by forming a delta-like series of small islands, for example), this can alter the salinity and nutrient relationships in estuarine environments. Barriers to free water exchange increase the hydraulic head of fresh water, reduce the inflow of saline water, and thus reduce the overall salinity and salinity range in the water body. With the reduction in saline water input, there is a concomitant reduction in the input of marine larvae to the water body, and the nature of the flora and fauna could change from a predominantly estuarine ecosystem that supports coastal fisheries to a fresh water system that is much more isolated from the marine environment.

The disposal of drilling muds and cuttings in a fresh water body would lead to more rapid filling of the lake or marsh (all very slow-flowing aquatic environments are slowly becoming shallower by continual deposition of sediments), hastening the loss of that habitat, and potentially altering the nature of the flora and fauna.

Produced Water. The disposal of produced water can pose problems because it often has a different chemical composition than surface waters. The toxic components of produced waters have already been emphasized for terrestrial systems, and their effects are potentially magnified in aquatic systems because they can be transported by water far from their point of introduction. All states require that discharges not be toxic, however, and most states have promulgated Water Quality Standards for individual toxic chemicals to control the discharge of these chemicals.

Produced waters are almost always more saline than fresh waters at selected drilling depths, and increased salinity in fresh water environments caused by produced water discharges reduces the utility of the water as a drinking water supply, as a source of irrigation water, and as a natural source of water for terrestrial ecosystems and aquatic biota.

The discharges of produced water that are more saline than estuarine water increase the salinity of the receiving waters. If discharges have low flow relative to the flow of the estuary (10% of estuary flow or less), the change may be small. On the other hand, with relatively high volume discharges relative to receiving water flow (half or more of the estuarine flow), the discharge would substantially increase receiving water salinity. The suitability of such sites for spawning and rearing of estuarine or marine species may be significantly impacted by the increased salinity. Because some species require a particular range of salinities in order to successfully reproduce, increases in salinity might reduce the amount of lower salinity water available for successful reproduction, thus causing declines in those populations.

Summary

The majority of impacts on inland ecosystems are associated with clearing native vegetation from sites for the location of drilling rigs or supporting facilities. While clearing, by itself, can be substantially detrimental to the ecosystem, the impact of clearing can be increased through poor management of wastes. Migration of saline produced water through reserve pit walls can contaminate soils (and groundwater), directly killing the vegetation required to maintain water balances and support animal communities.

The greatest impacts on coastal ecosystems are associated with the discharge of drilling fluids and cuttings (in estuarine and marine areas) and produced waters (in fresh water areas). Both of these processes are generally regulated at the State level, and if State laws and regulations are met, little impact is expected. If, however, the solid or saline components of rig discharges are not regulated, a full analysis of the fate and effects of these discharges should be carried out as part of the impact assessment.

Finally, the major mitigating actions are those that are implemented prior to drilling: locating rigs, reserve pits, processing facilities, and roads in areas where they will have minimal impacts, and designing facilities while considering the environment. Since the greater the area that is disrupted by exploration or production, the greater the environmental disruption, and the greater the chance of severe environmental effects, it is generally best to minimize the area affected. Disruption usually cannot be "undone" by covering an area used for exploration or production with "natural" materials since the "natural" structure of soils and sediments can take millennia to regenerate. So the focus of mitigation should be on finding site locations and site designs that have the smallest potential for adverse impacts, rather than fixing a site at a poor location or with a poor design once ecosystem damage has occurred.

POTENTIAL IMPACTS ON LAND USE

For the purposes of this discussion, land use represents the family of surface activities which may be practiced in a given area. Typical examples of land uses include agriculture, recreation, forestry, housing, and so forth. The practicability of any given land use depends on the land characteristics or other qualities. As a result, current or future land use opportunities may be affected by impacts to ground water, surface water, air, or a combination of these media. The following potential impacts are not exhaustive, nor does their inclusion represent any indication of the likelihood of occurrence.

Loss of Agricultural Land

Both plant and animal agriculture depend, in part, on soil productivity. As described earlier, oil and gas exploration and production activities may result in impacts to soil and soil productivity. Of particular concern is the accumulation of salts in soils, which may result in short- or long-term decreases in productivity. Thus, direct application of saline-produced waters or drilling fluids may result in a loss of soil productivity, thereby reducing the feasibility of agricultural uses for affected areas. Typically, Federal lands are used for grazing. Loss of soil productivity and subsequent impacts to vegetation may affect the potential for grazing usage.

Loss of Agricultural Irrigation

In many arid regions, the feasibility of agriculture depends on the availability of ground water for irrigation. Salt contamination from oil and gas operations to ground water in such areas may result in short-term plant damage and long-term loss of agricultural opportunities. Historical instances of such impacts have occurred in association with waterflooding and disposal-injection operations in proximity to agricultural water sources.

POSSIBLE PREVENTION/MITIGATION MEASURES

This section identifies techniques that may be appropriate for mitigation of potential impacts caused by oil and gas activities. Mitigation should be evaluated on a unit-by-unit site-specific basis, and the following measures should only be used as a guide to measures that might be available should the reviewer determine they might be appropriate.

- Construction of diversion ditches and containment berms can reduce the volume of run-off leaving a site. Reduction of run-off can reduce the chances of erosion and surface migration of sediments and wastes to surface waters.
- Reserve and mud pits may be constructed to contain total expected mud column volumes plus rainfall, reducing the chances of pit overtopping.
- Avoiding the addition to muds of known or suspected hazardous additives with less risk-prone substitutes can reduce the potential impacts to ground water in the event of contact, as well as simplify waste management.
- Installation of surface casing to below the deepest USDW seals the well from water bearing formations.
- The separation of wastes of known or suspected hazard from otherwise low hazard materials may reduce the potential impacts resulting from a release of pit contents.
- Lining of pits can impede percolation of fluid in the pit.
- Squeezing of fresh water sands with cement while drilling can inhibit migration of contaminants into the zone and inhibit ground water draw down.
- Secondary containment for above-ground tanks and containers can reduce impacts in events of failure.
- Dewatering of mud and reserve pit contents before burial may reduce the chance of downward transport of contaminants to shallow aquifers. Similarly, grading of soils covering pits may reduce the chances of infiltration of rain water which may migrate to ground water.
- Because of the potential for migration of injected fluids via abandoned wells in some geological settings, current Class II Well requirements generally specify the need to identify and plug damaged or improperly plugged abandoned wells within some distance of an injection well. This practice may reduce the chances of migration of injected fluids to USDWs.
- The separation of oily material from water based drilling fluids and the skimming of oil from the surface of produced water storage pits can serve to reduce the potential impacts which may result from releases of these pit wastes, and increase the recovery of product.

- Flaring of waste gases at high temperatures may reduce emissions of products of incomplete combustion.

- Casing integrity tests reduces the chances of migration of fluids between zones.

- Directional drilling may be used in conjunction with siting. Directional drilling places the bottom of the well under an inaccessible surface location, i.e. under a river, lake, city or other occupied place where vertical drilling is impractical. Are extreme example is horizontal drilling, which allow -- access to allow formations. However, directional wells are more expensive to drill than vertical wells.

- Monitoring of production water percentage can alert operator to any injection water or formation water migration so that remedial measures can be rapidly taken.

- Injection tracer surveys may reduce chances of injected water going into thief zones.

- Monitoring systems on underground pipelines can prevent soil/ground water contamination. Underground piping may also be made of corrosion resistant materials, or be protected using cathodic protection or other devices.

- Before fracturing jobs are undertaken the engineer/geologist should verify well logs and identify and assess location of nearby wells (both potable water and other wells) to make sure that fluid migration from the fracturing zone will not jeopardize fresh water aquifers.

- Timely closure of all pits and sumps.

- Contaminated soil may be removed to a proper disposal facility.

- Pretreatment of wastes before landfarming can reduce the potential for plant and soil impacts by reducing excessive chloride, oil and grease, and phytotoxic constituent concentrations.

- Quality of injected fluid/steam/chemical/gas should be monitored closely to prevent downhole formation contamination and prevent downhole equipment failure.

- General field facility monitoring and maintenance.

- Educating field personnel on awareness of the environment and environmental requirements.

- Locate facilities at the edge rather than the center of habitat types as much as possible.

- Minimize the area disturbed by each activity and site activities by considering rare habitats, sensitive species, water bodies, etc., and how disturbance may result in cumulative impacts on the entire ecosystem.

- Time activities to avoid disturbing plants and animals during crucial seasons in their life cycles (mating, etc.).

SUMMARY OF INFORMATION THAT SHOULD BE ADDRESSED IN NEPA DOCUMENTATION

The following is a list of questions that may be appropriate to ask about oil and gas operations when reviewing NEPA documentation:

- Has baseline data been collected to establish natural flow rates of ground water prior to disturbance? What are the designated and actual uses of ground water? Where are the nearest users of ground water located? What are the locations of all active, inactive, and plugged wells in the area? What are the uses of each of these wells?

- Has baseline data been collected to establish natural flow rates of surface water prior to disturbance? What are the designated and actual uses of surface water? Where are the nearest users located? Are streams in the area "losing streams" or "gaining streams?"

- What materials will be put into the reserve pit? Will any sampling be conducted to confirm pit contents? Is there a leak-detection system or monitoring system associated with the reserve pit? Is the anticipated closure of the reserve pit described in detail?

- What are the concentrations of all constituents in the mud to be used for drilling at each well? Will the type of mud be changed at any time during drilling? What are the expected constituents and volumes produced?

- What are the expected constituents (and their concentrations) of any produced water at each facility?

- How will the produced water be managed? Will the water be treated prior to disposal? If disposal involves land treatment or evaporation/percolation, have the areas for direct application (and any potential associated run-off areas) been surveyed for important species? If a potential impact is suspected, what actions will be taken? Is the closure of these units described in detail?

- Is the potential area of influence surrounding the well (e.g., aquifers that are penetrated, etc.) monitored for change in chemical compositions or flow characteristics? How often will the monitoring take place? Who will review the results? Does the monitoring account for seasonal variations? Are all ground-water discharge areas (e.g., springs, etc.) monitored? If a potential impact is suspected, what actions will be taken? Is well closure described in detail?

- Will service companies at each facility or site conduct any monitoring or sampling (ground water, surface water, air, soils, waste, ecosystems, etc.) or report these results? What is the planned frequency?

- What is the overall water balance for the site, including drilling, production, and closure? What is the design capacity of each pit onsite, and does this capacity account for a specific storm event (10-year, 50-year, or 100-year)? What is the planned freeboard on each pit?

- What waste will be generated onsite during each activity (e.g., drilling, stimulation, workover, closure, etc.), and how will they be managed?

- What baseline conditions are described? Describe the monitoring of these conditions during active operations, closure, and reclamation (include frequency, sample methodology, sample placement, and methods of analysis).

- Are cumulative impacts over the life of the facility or field (including possible expansions) described?

- Prior to conducting a fracturing job, has the strength of the formation been determined? What is the range of impact expected? Will any other formations be involved? Have all wells in the area (active or abandoned) been located? What is the distance to the nearest aquifer (vertical and/or horizontal)?

- Prior to water, steam, or other injection, have any thief zones been identified? What is the range or extent of injection expected? Will any other formations be involved? Have all wells in the area (active or abandoned) been located? What are the constituents of the injection fluid? What is the distance to the nearest aquifer (vertical and/or horizontal)?

- Is there a leak detection system for any gathering lines or tanks used to store produced water, crude oil, or wastes? Do all tanks have secondary containment? Describe any formalized plans to respond to accidental releases.

- How will air emissions be minimized? What technologies will be implemented for fugitive dust emissions control? What are the constituents of each emission stream?

- Is there containment for releases from emergency or pressure-release valves associated with any phase of the operation?

- Will there be any future consequences of cessation of oil and gas withdrawal?

- Are there any endangered, threatened, or rare species or critical habitats in the area?

- Are the pre- and post-oil and gas land uses compared?

- Have the different types of habitat been surveyed and mapped in the area?

- Will wildlife access to all pits and ponds be controlled?

- Is fencing, road building, or other disturbance expected to cause impacts on species behavioral practices (fragmentation)?

- Are activities timed to occur during seasons not crucial to wildlife (mating, etc.) or plants?
- How will the site be reclaimed?

OTHER WASTES NOT UNIQUELY ASSOCIATED WITH OIL AND GAS EXPLORATION AND PRODUCTION

In addition to the wastes described in the above sections, oil and gas operations generate other wastes, such as spent solvents and used oil, that are not uniquely related to the industry. These wastes do not meet the exclusion from RCRA Subtitle C [40 CFR 261.4(b)(5)] regulation. See the section on RCRA Regulations for further discussion of this exclusion.

Wastes not uniquely related to oil and gas include but are not limited to: unused fracturing fluids or acids; drum rinsate; vacuum truck rinsate; used equipment lubrication oils; waste solvents; boiler scrubber fluids, sludges, and ash; incinerator ash; pigging wastes from transportation lines; sanitary wastes, and laboratory wastes.

In some cases, these wastes are co-mingled with excluded wastes such as produced water in reserve pits, or other units. Aside from possible RCRA compliance issues, managing these wastes in reserve pits or other units may cause potential impacts to the environment. For example, solvents may tend to be fairly mobile and may be released to ground water if disposed of in a unit that is unlined. Management of these wastes should be sufficiently addressed in the NEPA documentation for each oil and gas operation, where applicable. In addition, proper monitoring of storage and disposal units for these wastes should be described.

IDENTIFICATION OF ADDITIONAL POTENTIAL IMPACTS

Although potential environmental impacts are described in the above text, there are additional potential impacts that may be caused by oil and gas operations. Additional issues and their related statutes are identified below:

- Spills or releases of hazardous substances (Comprehensive Environmental Response, Compensation, and Liability Act)
- Underground tanks (Resource Conservation and Recovery Act)
- PCBs or other toxic substances such as asbestos (Toxic Substance Control Act)
- Access roads or other off road vehicle travel (Clean Air Act)
- Endangered, threatened or otherwise protected species (Endangered Species Act, Bald and Golden Eagle Protection Act, Migratory Bird Treaty Act, Wild and Free-Roaming Horses and Burros Act)
- Archaeological Resources (Antiquities Act, Historic Sites, Buildings, and Antiquities Act, Archaeological And Historic Preservation Act, and National Historic Preservation Act)
- Socioeconomic impacts, including impacts on Native Americans (American Indian Religious Freedom Act).

LIST OF CONTACTS

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GLOSSARY

Abandon: To cease producing oil or gas from a well when it becomes unprofitable. A wildcat may be abandoned after it has been proven nonproductive. Usually, when a well is abandoned, some of the casing is removed and salvaged and one or more cement plugs are placed in the borehole to prevent migration of fluids between the various formations. In many States, abandonment must be approved by an official regulatory agency before being undertaken.

Acidize: To treat oil-bearing limestone or other formations, using a chemical reaction with acid, to increase production. Hydrochloric or other acid is injected into the formation under pressure. The acid etches the rock, enlarging the pore spaces and passages through which the reservoir fluids flow. The acid is then pumped out and the well is swabbed and put back into production. Chemical inhibitors combined with the acid prevent corrosion of the pipe.

Adsorption: The adhesion of a thin film of a gas or liquid to the surface of a solid. Liquid hydrocarbons are recovered from natural gas by passing the gas through activated charcoal, which extracts the heavier hydrocarbons. Steam treatment of the charcoal removes the adsorbed hydrocarbons, which are then collected and recondensed.

Aeration: The technique of injecting air or other gas into a fluid. For example, air is injected into drilling fluid to reduce the density of the fluid.

Air Drilling: A method of rotary drilling that uses compressed air as its circulation medium. This method of removing cuttings from the wellbore is as efficient or more efficient than the traditional methods using water or drilling mud; in addition, the rate of penetration is increased considerably when air drilling is used. However, a principal problem in air drilling is the penetration of formations containing water, since the entry of water into the system reduces its efficiency.

Alkalinity: The combining power of a base, or alkali, as measured by the number of equivalents of an acid with which it reacts to form a salt.

Annular Injection: Long-term disposal of wastes between the outer wall of the drill stem or tubing and the inner wall of the casing or open hole.

Annulus or Annular Space: The space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

API: The American Petroleum Institute. Founded in 1920, this national oil trade organization is the leading standardizing organization on oil-field drilling and producing equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas.

Artificial Lift: Any method used to raise oil to the surface through a well after reservoir pressure has declined to the point at which the well no longer produces by means of natural energy. Artificial lift may also be used during primary recovery if the initial reservoir pressure is inadequate to bring the hydrocarbons to the surface. Sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift are the most common methods of artificial lift.

Attapulgite: A fibrous clay mineral that is a viscosity-building substance, used principally in saltwater-based drilling muds.

Barite: Barium sulfate, $BaSO_4$; a mineral used to increase the weight of drilling mud. Its specific gravity is 4.2.

Barrel (bbl): A measure of volume for petroleum products. One barrel (1 bbl) is equivalent to 42 U.S. gallons or 158.97 liters. One cubic meter (1 m^3) equals 6.2897 bbl.

Basin: A synclinal structure in the subsurface, formerly the bed of an ancient sea. Because it is composed of sedimentary rock and its contours provide traps for petroleum, a basin is a good prospect for exploration. For example, the Permian Basin in West Texas is a major oil producer.

Bentonite: A colloidal clay, composed of montmorillonite, which swells when wet. Because of its gel-forming properties, bentonite is a major component of drilling muds.

Blowout Preventer (BOP): Equipment installed at the wellhead at surface level on land rigs and on the seafloor of floating offshore rigs to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations.

Blow Out: To suddenly expel oil/gas-well fluids from the borehole with great velocity.

Borehole: The wellbore; the hole made by drilling or boring.

Brine: Water that has a large quantity of salt, especially sodium chloride, dissolved in it; salt water.

Casinghead Gas: Gas produced with oil.

Casing String: Casing is manufactured in lengths of about 30 ft, each length or joint being joined to another as casing is run in a well. The entire length of all the joints of casing is called the casing string.

Cement Plug: A portion of cement placed at some point in the wellbore to seal it.

Christmas Tree: Assembly of fittings and valves at the tip of the casing of an oil well that controls the flow of oil from the well.

Circulate: To pass from one point throughout a system and back to the starting point. Drilling fluid circulates from the suction pit through the drill pipe to the bottom of the well and returns through the annulus.

Close-in: A well capable of producing oil or gas, but temporarily not producing.

Collar: A coupling device used to join two lengths of pipe. A combination collar has left-hand threads in one end and right-hand threads in the other. A drill collar.

Completion Fluid: A special drilling mud used when a well is being completed. It is selected not only for its ability to control formation pressure, but also for its properties that minimize formation damage.

Completion Operations: Work performed in an oil or gas well after the well has been drilled to the point at which the production string of casing is to be set. This work includes setting the casing, perforating, artificial stimulation, production testing, and equipping the well for production, all prior to the commencement of the actual production of oil or gas in paying quantities, or in the case of an injection or service well, prior to when the well is plugged and abandoned.

Condensate: A light hydrocarbon liquid obtained by condensation of hydrocarbon vapors. It consists of varying proportions of butane, propane, pentane, and heavier fractions, with little or no ethane or methane.

Conductor Pipe: A short string of large-diameter casing used offshore and in marshy locations to keep the top of the wellbore open and to provide a means of conveying the upflowing drilling fluid from the wellbore to the mud pit.

Coning: The encroachment of reservoir water into the oil column and well.

Connate Water: The original water retained in the pore spaces, or interstices, of a formation from the time the formation was created.

Crude Oil: Unrefined liquid petroleum. It ranges in gravity from 9° to 55° API and in color from yellow to black, and it may have a paraffin, asphalt, or mixed base. If a crude oil, or crude, contains a sizable amount of sulfur or sulfur compounds, it is called a sour crude; if it has little or no sulfur, it is called a sweet crude. In addition, crude oils may be referred to as heavy or light according to API gravity, the lighter oils having the higher gravities.

Cuttings: The fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

Deflocculation: The dispersion of solids that have stuck together in drilling fluid, usually by means of chemical thinners.

Defoamer: Any chemical that prevents or lessens frothing or foaming in another agent.

Dehydrate: To remove water from a substance. Dehydration of crude oil is normally accomplished by emulsion treating with emulsion breakers. The water vapor in natural gas must be removed to meet pipeline requirements; a typical maximum allowable water vapor content is 7 lb per MMcf.

Demulsify: To resolve an emulsion, especially of water and oil, into its components.

Desander: A centrifugal device used to remove fine particles of sand from drilling fluid to prevent abrasion of the pumps. A desander usually operates on the principle of a fast-moving stream of fluid being put into a whirling motion inside a cone-shaped vessel.

Desiccant: A substance able to remove water from another substance with which it is in contact. It may be liquid (as triethylene glycol) or solid (as silica gel).

Desilter: A centrifugal device, similar to a desander, used to remove very fine particles, or silt, from drilling fluid to keep the amount of solids in the fluid to the lowest possible level. The lower the solids content of the mud is, the faster the rate of penetration.

Development Well: A well drilled in proven territory in a field to complete a pattern of production.

Drill Collar: A heavy, thick-walled tube, usually steel, used between the drill pipe and the bit in the drill stem to weight the bit in order to improve its performance.

Drilling Fluid: The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspended medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase. Drilling fluids are circulated down the drill pipe and back up the hole between the drill pipe and the walls of the hole, usually to a surface pit. Drilling fluids are used to lubricate the drill bit, to lift cuttings, to seal off porous zones, and to prevent blowouts. There are two basic drilling media: muds (liquid) and gases. Each medium comprises a number of general types. The type of drilling fluid may be further broken down into numerous specific formulations.

Drill Pipe: The heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 ft long are coupled together by means of tool joints.

Drill Stem: The entire length of tubular pipes, composed of the kelly, the drill pipe, and drill collars, that make up the drilling assembly from the surface to the bottom of the hole.

Drill String: The column, or string, of drill pipe, not including the drill collars or kelly. Often, however, the term is loosely applied to include both the drill pipe and drill collars.

Dry Hole: Any well that does not produce oil or gas in commercial quantities. A dry hole may flow water, gas, or even oil, but not enough to justify production.

Emulsion: A mixture in which one liquid, termed the dispersed phase, is uniformly distributed (usually as minute globules) in another liquid, called the continuous phase or dispersion medium. In an oil-water emulsion, the oil is the dispersed phase and the water the dispersion medium; in a water-oil emulsion the reverse holds. A typical product of oil wells, water-oil emulsion also is used as a drilling fluid.

Emulsion Breaker: A system, device, or process used for breaking down an emulsion and rendering it into two or more easily separated compounds (as water and oil). Emulsion breakers may be (1) devices to heat the emulsion, thus achieving separation by lowering the viscosity of the emulsion and allowing the water to settle out; (2) chemical compounds, which destroy or weaken the film around each globule of water, thus uniting all the drops; (3) mechanical devices such as settling tanks and wash tanks; or (4) electrostatic treaters, which use an electric field to cause coalescence of the water globules. This is also called electric dehydration.

Enhanced Oil Recovery (EOR): A method or methods applied to depleted reservoirs to make them productive once again. After an oil well has reached depletion, a certain amount of oil remains in the reservoir, which enhanced recovery is targeted to produce. EOR can encompass secondary and tertiary production.

Field: A geographical area in which a number of oil or gas wells produce from a continuous reservoir. A field may refer to surface area only or to underground productive formations as well. In a single field, there may be several separate reservoirs at varying depths.

Flocculation: A property of contaminants or special additives to a drilling fluid that causes the solids to coagulate.

Flowing Well: A well that produces oil or gas without any means of artificial lift.

Foaming Agent: A chemical used to lighten the water column in gas wells, in oil wells producing gas, and in drilling wells in which air or gas is used as the drilling fluid so that the water can be forced out with the air or gas to prevent its impeding the production or drilling rate.

Formation: A bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface.

Formation Pressure: The pressure exerted by fluids in a formation, recorded in the hole at the level of the formation with the well shut in. It is also called reservoir pressure or shut-in bottomhole pressure.

Formation Water: The water originally in place in a formation.

Fracturing: A method of stimulating production by increasing the permeability of the producing formation. Under extremely high hydraulic pressure, a fluid is pumped downward through tubing or drill pipe and forced into the perforations in the casing. The fluid enters the formation and parts or fractures it. Sand grains, aluminum pellets, glass beads, or similar materials are carried in suspension by the fluid into the fractures. These are called propping agents. When the pressure is released at the surface, the fracturing fluid returns to the well, and the fractures partially close on the propping agents, leaving channels through which oil flows to the well.

Free Water: The water produced with oil. It usually settles out within 5; minutes when the well fluids become stationary in a settling space within a vessel.

Gas Lift: The process of raising or lifting fluid from a well by injecting gas down the well through tubing or through the tubing-casing annulus. Injected gas aerates the fluid to make it exert less pressure than the formation does; consequently, the higher formation pressure forces the fluid out of the wellbore. Gas may be injected continuously or intermittently, depending on the producing characteristics of the well and the arrangement of the gas-lift equipment.

Gas-Oil Ratio: Number of cubic feet of gas produced with a barrel of oil.

Gathering Line: A pipeline, usually of small diameter, used in gathering crude oil from the oil field to a point on a main pipeline.

Glycol Dehydrator: A processing unit used to remove all or most of the water from gas. Usually a glycol unit includes a tower, in which the wet gas is put into contact with glycol to remove the water, and a reboiler, which heats the wet glycol to remove the water from it so the glycol can be recycled.

Hard Water: Water that contains dissolved compounds of calcium, magnesium, or both.

Heater-treater: A vessel that heats an emulsion and removes water and gas from the oil to raise it to a quality acceptable for pipeline transmission. A heater-treater is a combination of a heater, free-water knockout, and oil and gas separator.

Hydraulic Fracturing: The forcing into a formation of liquids under high pressure to open passages for oil and gas to flow through and into the wellbore.

Hydrocarbons: Organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solid.

Hydrostatic Head: The pressure exerted by a body of water at rest. The hydrostatic head of fresh water is 0.433 per foot of height. The hydrostatic heads of other liquids may be determined by comparing their gravities with the gravity of water.

Inhibitor: An additive used to retard undesirable chemical action in a product; added in small quantity to gasolines to prevent oxidation and gum formation, to lubricating oils to stop color change, and to corrosive environments to decrease corrosive action.

Intermediate Casing String: The string of casing set in a well after the surface casing to keep the hole from caving in. Sometimes the blowout preventers can be attached to it. The string is sometimes called protection casing.

Interstice: A pore space in a reservoir rock.

Joint: A single length (30 ft) of drill pipe or of drill collar, casing, tubing, or rod that has threaded connections at both ends. Several joints screwed together constitute a stand of pipe.

Kelly: The heavy metal shaft, four- or six-sided, suspended from the swivel through the rotary table and connected to the topmost joint of drill pipe to turn the drill stem as the rotary table turns. It has a bored passageway that permits fluid to be circulated into the drill stem and up the annulus, or vice versa.

Log: A systematic recording of data, as from the driller's log, mud log, electrical well log, or radioactivity log. Many different logs are run in wells being produced or drilled to obtain information about various characteristics of downhole formations.

Manifold: An accessory system of piping to a main piping system (or another conductor) that serves to divide a flow into several parts, to combine several flows into one, or to reroute a flow to any one of several possible destinations.

Marginal Well: An oil or gas well that produces such a small volume of hydrocarbons that the gross income therefrom provides only a small margin of profit or, in many cases, does not even cover the cost of production.

Mud: The liquid circulated through the wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, the mud used in modern drilling operations is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, diesel oil, or crude oil and may contain one or more conditioners.

Mud Pit: A reservoir or tank, usually made of steel plates, through which the drilling mud is cycled to allow sand and fine sediments to settle out. Additives are mixed with mud in the pit, and the fluid is temporarily stored there before being pumped back into the well. Mud pits are also called shaker pits, settling pits, and suction pits, depending on their main purpose.

Oil and Gas Separator: An item of production equipment used to separate the liquid components of the well stream from the gaseous elements. Separators are vertical or horizontal and are cylindrical or spherical in shape. Separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top. A float valve or other liquid-level control regulates the level of oil in the bottom of the separator.

Oil-based Mud: An oil mud that contains from less than 2 percent up to 5 percent water. The water is spread out, or dispersed, in the oil as small droplets.

Oil Field: The surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area but also the reservoir, wells, and production equipment.

Packer: A piece of downhole equipment, consisting of a sealing device, a holding or setting device, and an inside passage for fluids, used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore by sealing off the space. It is usually made up in the tubing string some distance above the producing zone. A sealing element expands to prevent fluid flow except through the inside bore of the packer and into the tubing. Packers are classified according to configuration, use, and method of setting and whether or not they are retrievable (i.e., whether they can be removed when necessary, or whether they must be milled or drilled out and thus destroyed).

Packer Fluid: A liquid, usually mud but sometimes salt water or oil, used in a well when a packer is between the tubing and casing. Packer fluid must be heavy enough to shut off the pressure of the formation being produced, must not stiffen or settle out of suspension over long periods of time, and must be noncorrosive.

Perforate: To pierce the casing wall and cement to provide holes through which formation fluids may enter or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires bullets or shaped charges electrically detonated from the surface.

Permeability: A measure of the ease with which fluids can flow through a porous rock.

Pig: A scraping tool that is forced through a pipeline or flow line to clean out accumulations of wax, scale, and so forth, from the inside walls of a pipe. A cleaning pig travels with the flow of product in the line, cleaning the walls of the pipe with blades or brushes. A batching pig is a cylinder with neoprene or plastic cups on either end used to separate different products traveling in the same pipeline.

Porosity: The quality or state of possessing pores (as a rock formation). The ratio of the volume of interstices of a substance to the volume of its mass.

Primary Recovery: Oil production in which only existing natural energy sources in the reservoir provide for movement of the well fluids to the wellbore.

Produced Water: The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. It can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process. Its quality can vary from low salinity (acceptable for livestock or irrigation) to salt levels several times that of sea water.

Producing Zone: The zone or formation from which oil or gas is produced.

Production: The phase of the petroleum industry that deals with bringing the well fluids to the surface and separating them and with storing, gauging, and otherwise preparing the product for the pipeline.

Production Casing: The last string of casing or liner that is set in a well, inside of which is usually suspended the tubing string.

Propping Agent: A granular substance (as sand grains, walnut shells, or other material) carried in suspension by the fracturing fluid that serves to keep the cracks open when the fracturing fluid that serves to keep the cracks open when the fracturing fluid is withdrawn after a fracture treatment.

Radioactive Tracer: A radioactive material (often carnotite) put into a well to allow observation of fluid or gas movements by means of a tracer survey.

Reserve Pit: Drilling related pit used to store and/or dispose of used drilling muds and drill cuttings.

Reservoir: A subsurface, porous, permeable rock body in which oil or gas or both are stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The three basic types of hydrocarbon reservoirs are oil, gas, and condensate. An oil reservoir generally contains three fluids--gas, oil, and water--with oil the dominant product. In the typical oil reservoir, these fluids occur in different phases because of the variance in their gravities. Gas, the lightest, occupies the upper part of the reservoir rocks; water, the lower part; and oil, the intermediate section. In addition to occurring as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. In a condensate reservoir, the hydrocarbons may exist as a gas, but when brought to the surface, some of the heavier ones condense to a liquid or condensate. AT the surface the hydrocarbons from a condensate reservoir consist of gas and a high-gravity crude (i.e., the condensate). Condensate wells are sometimes called gas-condensate reservoirs.

Resistivity: The electrical resistance offered to the passage of current; the opposite of conductivity.

Rig: The derrick, drawworks, and attendant surface equipment of a drilling or workover unit.

Rotary: The machine used to impart rotational power to the drill stem while permitting vertical movement of the pipe for rotary drilling. Modern rotary machines have a special component, the rotary bushing, to turn the kelly bushing, which permits vertical movement of the kelly while the stem is turning.

Secondary Recovery: Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from extraneous sources) into the wellbore. This injection effects a restoration of reservoir energy, which moves the formerly unrecoverable secondary reserves through the reservoir to the wellbore.

Sediment: The matter that settles to the bottom of a liquid; also called tank bottoms, basic sediment, and so forth.

Shale Shaker: A series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. It is also called a shaker.

Sour: Containing hydrogen sulfide or caused by hydrogen sulfide or another sulfur compound.

Specific Gravity: The ratio of the weight of a substance at a given temperature to the weight of an equal volume of a standard substance at the same temperature. For example, if 1 $in.^3$ of water at 39°F weighs 1 unit and 1 $in.^3$ of another solid or liquid at 39°F weighs 0.95 unit, then the specific gravity of the substance is 0.95. In determining the specific gravity of gases, the comparison is made with the standard of air or hydrogen.

Spud: To move the drill stem up and down in the hole over a short distance without rotation. Careless execution of this operation creates pressure surges that can cause a formation to break down, which results in lost circulation.

Spud In: To begin drilling; to start the hole.

Stock Tank: A crude oil storage tank.

Stripper: A well nearing depletion that produces a very small amount of oil or gas.

Sump: A low place in a vessel or tank used to accumulate settlings that are later removed through an opening in the bottom of the vessel.

Supernatant: A liquid or fluid forming a layer above settled solids.

Surface Pipe: The first string of casing set in a well after the conductor pipe, varying in length from a few hundred feet to several thousand.

Surfactant: A substance that affects the properties of the surface of a liquid or solid by concentrating on the surface layer. The use of surfactants can ensure that the surface of one substance or object is in thorough contact with the surface of another substance.

Tank Battery: A group of production tanks located in the field that store crude oil.

Tertiary Recovery: A recovery method used to remove additional hydrocarbons after secondary recovery methods have been applied to a reservoir. Sometimes more hydrocarbons can be removed by injecting liquids or gases (usually different from those used in secondary recovery and applied with different techniques) into the reservoir.

Tubing: Small-diameter pipe that is run into a well to serve as a conduit for the passage of oil and gas to the surface.

This short paper discusses the results of a survey of pending and resolved complaint reports on file with the Department of Agriculture and the Texas Railroad Commission. The complaints allege damages from oil and gas wells. Types of damages known or believed to have occurred are described.

U.S. Environmental Protection Agency. September 1990. Reducing Risk: Setting Priorities and Strategies for Environmental Protection.

Reducing Risk is a report from the Science Advisory Board (SAB) to the administrator of EPA concerning its recommendations for the inclusion of risk based considerations in establishing EPA strategies and priorities. The SAB identifies the potential benefit of including total risk and non-human-health related risk considerations into the process of determining how best to allocate resources. In particular, SAB recommends a policy of maximum risk reduction and the inclusion of ecological risk to be considered on par with direct human health risk.

U.S. Environmental Protection Agency. September 10-13, 1990. Proceeding of the First International Symposium on Oil and Gas Exploration and Production Waste Management Practices. New Orleans, LA, USA.

These proceedings contain 91 papers from government, industry, and academic sources on topics ranging from waste stream characterization to existing and novel management and disposal practices as well as contaminant remediation and waste minimization.

Warner, D., and C. McConnell. Evaluation of the Groundwater Contamination Potential of Abandoned Wells by Numerical Modelling," *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 477-483.

This paper discusses results of numerical modelling efforts to estimate the potential for migration of pollutants via abandoned wells to subsurface waters. Results indicate the potential may range from probable to zero depending on well condition and geological factors.

Welker, A.J. 1985. The Oil and Gas Book.

The Oil and Gas Book is a thorough overview of oil and gas exploration and production written for the layman. The book describes E&P from leasing through spudding, primary recovery to thermal EDR, and abandonment. Little attention is paid to waste and waste management.

Zimmerman, P.K., and J.D. Robert. Landfarming Oil Based Drill Cuttings *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 565-576.

This paper discusses the methods and results of landfarming oil based drill cuttings at 32 well sites in Alberta, Canada. After 3 years, constituent analysis revealed adequate decreases in oil, salt, and electrical conductivity levels to expect each site to meet or exceed government revegetation standards.

Deuel, L.E., Jr. Evaluation of the Limiting Constituents Suggested for Land Disposal of Exploration and Production Wastes *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 411-430.

> This paper discusses the technical basis for suggested threshold values of limiting constituents for land application of exploration and production wastes. Thresholds are presented as generic limits below which soil, plant, and ground water damages may be minimized from burial, land farming, and road spreading disposal options.

Englehardt, F.R., J.P. Ray, A.H. Gillam, eds. 1989. Drilling Wastes. Elsevier Science Publishing Co., Inc., New York, NY.

> This book is a compilation of 42 papers presented at the 1988 International Drilling Conference on Drilling Wastes, held in Calgary, Alberta, Canada. The papers relate to on- and off-shore operations and focus on fate and effects, waste constituents, management approaches, or some combination of these. Ranging from general to fairly technical, the reports provide industry, government, and academic perspectives on the generation and management of drilling wastes.

Hardisty, P.E., et al. Nature, Occurrence, and Remediation of Groundwater Contamination at Alberta Sour Gas Plants *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 635-645.

> This paper presents the results of a study of ground-water contaminant occurrence and remediation at 55 sour gas plants in Alberta. Results indicated some level of contamination at all but one of the plants, with remediation activities underway at very few of the facilities. Most contamination incidents were linked to migration from onsite ponds and landfills. Chlorides, dissolved organics, and free phase condensates were the most commonly detected pollutants.

Kennedy, A.J., et al. Oil Waste Road Application Practices at the Esso Resources Canada LTD., Cold Lake Production Project *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 689-701.

> This paper presents the case history of the use of separator sludge solids, tank bottoms, and residual oil field solid wastes for road surfacing materials.

Macyk, T.M., F.I. Nikiforuk, and D.K. Weiss. Drilling Waste Landspreading Field Trial in the Cold Lake Heavy Oil Region, Alberta, Canada *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 267-279.

> This paper discusses the results of field tests designed to measure the impacts of various loading rates for land application of freshwater gel, NaCl, and KCl drilling wastes. EC, pH, plant yield, and various physical and chemical soil properties were measured. As loading rates were varied according to rate Cl/unit area, no

information of hydrocarbons or other constituents of the wastes was presented. Results indicate impacts ranging from minimal to severe for lowest to highest loading rates.

McFarland, Mark L., D.N. Ueckert, and S. Hartman. Evaluation of Selective Placement Burial for Disposal of Drilling Fluids in West Texas," *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 455-466.

The paper discusses results of field trials of pit waste burial varying depths beneath surface soil. Mobility of salts and metals as well as success of revegetation is discussed.

Miller, H.T., and E.D. Bruce. Pathway Exposure Analysis and the Identification of Waste Disposal Options for Petroleum Production Wastes Containing Naturally Occurring Radioactive Materials *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 731-744.

This paper discusses the occurrence of NORM in formation fluids and gas, the distribution of NORM in surface processing equipment (e.g., pipes, tank bottoms, soils) and various options for disposal of contaminated materials.

National Research Council. 1989. Land Use Planning and Oil and Gas Leasing on Onshore Federal Lands. National Academy Press. Washington, D.C.

This document presents the results of study performed by the Committee on Onshore Oil and Gas Leasing concerning oil and gas leasing on Federal lands. The report specifically addresses existing BLM and Forest Service practices for granting leases and the extent to which such practices address environmental values vis-à-vis competing resource interests. Regulations affecting the agencies and operators are discussed. Further, wildlife and other environmental considerations are addressed.

Nefl, J.M. No date. Bioaccumulation and Biomagnification of Chemicals from Oil Well Drilling and Production Wastes in Marine Food Webs: A Review.

This paper presents a review of general literature related to the bioaccumulation and biomagnification of exploration and production waste constituents in marine life. Descriptions of used drilling fluids and produced waters are provided, including typical constituent concentration ranges. Physical and biochemical pathways of exposure and accumulation are examined.

Texas Department of Agriculture, Office of Natural Resources. No date. Agricultural Land and Water Contamination from Injection Wells, Disposal Pits, and Abandoned Wells Used in Oil and Gas Production.

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Adamanche, I. No date. Contaminated Sulfur Recovery by Froth Flotation.

The paper discusses the design and performance characteristics of a froth flotation sulfur recovery cycle used to reclaim contaminated sulfur block base pad sulfur in Canada. Comparison with "remelt and filter" processes suggests greater recovery with less hazardous waste products may be achieved using froth flotation.

API. January 15, 1989. Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations.

This document discusses general waste and management considerations related to onshore oil and gas operations. The emphasis of the recommendations is on the distinction between RCRA exempt and non-exempt wastes and suggestions for minimizing the volume of wastes which may be subject to Subtitle C review. Separate sections describe wastes generated, waste management and fluid management units, suggested waste management practices, and the Area Waste Management Plan concept.

Berry, et al. An Assessment of Produced Water Impacts to Low-Energy, Brackish Water Systems in Southeast Louisiana: A Project Summary *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 31-42.

The report presents summarized results of study of impacts of produced water discharges to surface receiving waters in Louisiana. Hydraulic behavior, Radium 226 activity, biotoxicity, chemical characteristics, chemical impacts, and bioaccumulation of constituents in systems were examined.

Boyle, C.A. Management of Amine Process Sludges *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 577-589.

This paper discusses waste characteristics and waste management options for wastes generated at sour gas processing plants using diethanolamine (DEA) of monoethanolamine (MEA). Landfilling, land treatment, deep well disposal, surface water discharge, and incineration options are compared. The authors recommend land treatment of process sludges as the most desirable disposal option.

Braun, J.E., and M.A. Peavy. Control of Waste Well Casing Vent Gas from a Thermally Enhanced Oil Recovery Operation *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 199-210.

This paper discusses one operator's experience with casing vent gas recovery systems used to reduce sulfur emissions and reclaim NGLs at its thermal enhanced oil recovery projects in California. The system separates NGLs and volatilized petroleum fractions from the gas stream for recovery while scrubbers remove SO_2 from flare exhausted. Stated benefits include increased production flow rate by reducing downhole back pressure, 99 percent hydrocarbon removal, and 95 percent sulfur removal.

Buchler, P.M. The Attenuation of the Aquifer Contamination in an Oil Refinery Stabilization Pond *in* Proceeding of the First International Symposium on Oil and Gas Exploration Waste Management Practices, September 10-13, 1990, pp. 109-116.

This report discusses the modification of bentonite clays to increase adsorption of polar organic molecules to the clays when used as pond liners. Results suggest that treating clays with quaternary ammonium cations can attenuate migration of organics by adsorption in addition to the normally expected reduction in permeability afforded by the clay liners.

Bureau of Land Management. May 7, 1990. Planning for Fluid Mineral Resources. U.S. Department of the Interior.

This document provides guidelines for the mandated preparation of Resource Management Plans for Federal lands including BLM, Forest Service, and Indian Lands. The document explicitly focuses on the inclusion of consideration of fluid mineral resources in preparation of RMPs. Chapters are organized around the sequence of administrative actions and decisions to be made in relation to proposed oil and gas exploration and production operations.

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The paper presents the analytical methods and results for tests of the physical and hydrological properties of subsoils at a commercial oil field waste land treatment unit. Results indicate that the vertical mobility of contaminants, including chlorides, is very low due to site specific conditions. After 5 years of treatment at the site, chlorides had migrated to a maximum depth of 18 inches.

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This paper describes the State's UIC Class II well program as currently implemented. Disposal and water flooding injection well restrictions and practices are described in addition to annular injection and road spreading disposal methods. Specific problems associated with annular injection are discussed.

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Viscosity: A measure of the resistance of a liquid to flow. Resistance is brought about by the internal friction resulting from the combined effects of cohesion and adhesion. The viscosity of petroleum products is commonly expressed in terms of the time required for a specific volume of the liquid to flow through an orifice of a specific size.

Volatile: Readily vaporized.

Waterflood: A method of secondary recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Usually, a waterflood involves the injection of water through wells specially set up for water injection and the removal of the water and oil from the wells drilled adjacent to the injection wells.

Weighting Material: A material with a specific gravity greater than that of cement; used to increase the density of drilling fluids or cement slurries.

Wellbore: A borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased); or a portion of it may be cased and a portion of it may be open.

Well Completion: The activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. the method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, conventional perforated completions, sand-exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

Wellhead: The equipment used to maintain surface control of a well, including the casinghead, tubing head, and Christmas tree.

Well Spacing: The regulation of the number and location of wells over a reservoir as a conservation measure.

Well Stimulation: Any of several operations used to increase the production of a well.

Wildcat: A well drilled in area where no oil or gas production exists.

Workover: One or more of a variety of remedial operations performed on a producing oil well to try to increase production. Examples of workover operations are deepening, plugging back, pulling and resetting the liner, squeeze-cementing, and so on.

Workover Fluids: A special drilling mud used to keep a well under control when it is being worked over. A workover fluid is compounded carefully so it will not cause formation damage.