

US EPA ARCHIVE DOCUMENT

**ASSOCIATED WASTE REPORT:
COMPLETION AND WORKOVER WASTES**

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U.S. Environmental Protection Agency
Office of Solid Waste
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1.0 INTRODUCTION

1.1 BACKGROUND

In Section 3001(b)(2)(A) of the 1980 Amendments to the Resource Conservation and Recovery Act (RCRA), Congress conditionally exempted several types of solid wastes from regulation as hazardous wastes. Among the categories of wastes exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, and production of crude oil or natural gas...." RCRA Section 8002(m) required the Administrator of the U.S. Environmental Protection Agency (EPA) to study these wastes and submit a report to Congress evaluating the status of their management. The Amendments also required the Administrator to determine whether to propose regulations under RCRA Subtitle C if it was determined that the wastes should be regulated as hazardous wastes. In July of 1988, the Agency completed the above-described activities, and reached a determination that regulation under RCRA Subtitle C was not warranted and that the wastes could be better controlled through improvements to existing State and Federal regulatory programs (53 FR 25446). Among those exploration and production (E&P) wastes exempted are "well completion, treatment, and stimulation fluids" and "workover wastes."

Currently, EPA is developing reports on various wastes that are associated with the exploration, development, and production of crude oil or natural gas and that are exempt from regulation as hazardous wastes under Subtitle C of RCRA. Initially, EPA has focused on evaluating three groups of associated wastes: crude oil tank bottoms and oily debris, dehydration and sweetening wastes, and completion and workover wastes. The purpose of these papers is to provide a better understanding of the wastes and their management. This report addresses completion and workover wastes. Section 1.2 below describes completion and workover operations as well as stimulation techniques and fluids used in both. Chapter 2 describes the wastes generated by well completion and workover operations in terms of volumes and characteristics. Chapter 3 describes waste management practices used for completion and workover wastes, and Chapter 4 provides an overview of the types of waste minimization and pollution prevention techniques that may be applicable to well completion and workover operations. Finally, Chapter 5 presents a brief summary and conclusions.

1.2 DESCRIPTION OF OPERATIONS

After a well has been drilled, it is "completed" if well logging and test data indicate that the well is capable of producing commercial quantities of oil or gas or, in the case of injection wells, capable of oil field related injection activities (i.e., enhanced recovery or oil field waste disposal). Completion includes a number of operations that may be necessary to allow the well to produce oil or gas or to allow injection for oil field waste disposal or enhanced recovery. These include installing and cementing casing, perforating the zone(s) of interest, installing the production tubing and downhole equipment, repairing damage that drilling may have caused to the formation, and possibly stimulating the well. During a well's active life, periodic "workovers" are necessary. Workovers can include a number of procedures intended to maintain or enhance production. These can include repairing or replacing downhole equipment, removing accumulated scale or paraffin from tubing or casing, and stimulating the formation to restore or

enhance production or injectivity. Wells are stimulated, either by treating with acid or fracturing, during completion or workover or both: it is common for wells to be stimulated at completion and then periodically throughout their lives.

Completion and workover operations are highly variable. While such operations have common purposes and use common elements, the operations that may be performed on a specific well at a given time are determined on the basis of a wide range of factors that are often unique to a formation or well. Similarly, although wastes generated by completion and workover operations may be generally similar, they are strongly affected by the specific operations performed on a well. The more common types of operations are described in some detail in the following subsections.

In general, completion and workover operations that are performed, and the fluids used, differ only in their timing: completion occurs when the well is first prepared for production or injection and workovers are maintenance operations performed on producing or injection wells. Few or none of the specific operations described below are performed only during completions or only during workovers. Thus, the inclusion of specific activities in one section should not be taken as an indication that the activity does not occur in other situations as well.

The following two subsections describe various types of completion and workover procedures (sections 1.2.1 and 1.2.2, respectively). Since well stimulation is common to both, stimulation techniques are described separately (in section 1.2.3). Because the fluids used in completions and workovers are similar, fluids also are described separately (in section 1.2.4). Finally, this chapter concludes with a brief discussion of the frequency with which completion and workover operations are performed (section 1.2.5). It should be noted that the "categorization" of operations--completion, workover, and well treatment or stimulation--roughly corresponds to the approach taken by EPA's Office of Water in their proposed effluent limitation guidelines for the offshore oil and gas extraction industry.

1.2.1 Well Completion Operations

As is noted above, completion involves downhole operations that ultimately allow oil or gas to be produced or allow oil and gas related injection activities. Completion operations include setting and cementing the casing; perforating the casing and cement to allow oil or gas to flow from the formation into the well bore; installing production tubing, packers, and downhole pumps and equipment; and gravel-packing. It can also include well stimulation, including acidizing or hydraulic fracturing. In general, the nature of the formation and reservoir dictate the methods of completion. Each of the major types of operations are described below.

Initially, fluids may be circulated down the well bore to control formation pressure and/or to seal off or temporarily plug the face of the producing formation so that fluids and solids are not lost to the formation during completion operations (and to protect the formation from damage by completion fluids). The loss of fluids and solids to the formation can be expensive and also can reduce the formation's permeability and

ultimate productivity. Sealing is accomplished by depositing a thin film of solids ("bridging agents") over the formation surface without forcing solids into the formation. Clearly, completion fluids should not reduce the permeability of the producing formation, and completion fluids and additives are selected so they cause a minimum of permanent plugging of formation pores. The nature of the producing formation thus dictates the composition of completion fluids used. Oil- or acid-soluble bridging agents are used, and are then dissolved by oil, acid, or brine when completion operations are finished.

Casing

Steel casing is installed in the bore hole primarily to isolate the various formations penetrated by the well. Casing seals the wellbore and prevents fluids in cased zones from entering, protects the formations from well fluids, and prevents cave-ins. It also provides an anchor for equipment used for downhole operations. Several types of casing may be installed in wells; site-specific conditions determine which types actually are installed. Each successive casing used in a well is of smaller diameter and is placed inside the preceding casing. Some casing operations (e.g., setting conductor pipe, installing surface and intermediate casings) may be accomplished as part of the drilling process; others (e.g., setting the oil string) are accomplished as part of the completion process.

Generally, prior to drilling, a conductor pipe (typically 20 to 50 feet long) is installed. It serves to support downhole equipment, to prevent cave-ins, and to facilitate the flow of drilling fluids to tanks or pits. Inside the conductor pipe (or if none is used, then inside the wellbore), surface casing is set to a depth of 500 feet or more. Surface casing is frequently set to depths greater than 1000 feet to isolate aquifers which are presently used or are expected to be used as drinking water supplies. The casing depth requirements are established by the State Oil and Gas Regulatory Agency and, in some cases, in conjunction with the Bureau of Land Management. When drilling reaches the depth to which surface casing is to be set, the casing is cemented in place by circulating cement down the casing and up into the annulus between the casing and the wall of the wellbore. Its purpose is to protect shallow fresh water aquifers from contamination by fluids introduced into the well or brought up to the surface from deeper in the well. It also serves to support the blowout preventers and other equipment. After the surface string of casing is cemented in place and drilling continues, smaller diameter intermediate casings may be used to isolate various intervening formations (e.g., to prevent contamination of fresh water aquifers, to prevent fluid loss to permeable formations, or for other reasons).

If a well drilled to the desired depth is found capable of producing commercial quantities of oil and/or gas, a decision to complete the well is made. In "cased" or "set-through" completions, a production casing (or "oil string" or "long string") that extends from the surface to or through the producing formation is installed. The casing is cemented in place throughout the pay zone and for some distance above. In many wells the long string or intermediate casing is cemented from the bottom of the wellbore to the base of the surface casing, or the casing is cemented in stages (stage cementing) to protect all the aquifers or to isolate specific zones. In open hole (or "barefoot" or "top set") completions, however, the production casing is run and cemented only to the top of the producing zone or only partially into the zone; the wellbore through

the producing zone is left open. Open hole completions are often not practical in unconsolidated formations but can provide substantial cost savings if they can be used (for example, in development wells drilled in known formations with well-consolidated rock).

In either type of completion, the casing is cemented into place as described below. The casing and cement are then perforated (also described below) to allow formation fluids to enter the wellbore, and the tubing through which produced fluids will flow is placed inside the production casing. The tubing is suspended from the wellhead and reaches to the producing zone. To seal the annular space between the casing and production tubing, packers are generally installed in wells with multiple producing zones. They are installed above the producing formation and prevent formation fluids from reaching the surface through the annulus; in wells intended to produce from two or more intervals, packers are also set below the producing interval(s). Packers also are used to isolate zones that are undergoing various completion or treatment operations. Where multiple formations are to be produced, separate strings of tubing, all inside the casing and isolated by packers in the tubing-casing annular space, may be installed; alternatively, in multiple completions, a single string of tubing may be isolated by packers and perforated at one or more intermediate levels. Before or after the tubing is run, the well may be treated to repair damage to the formation or stimulated to initiate production. Operations and fluids that may be used in these treatments are described in sections 1.2.3 and 1.2.4.

The annular space above the packer(s) may be filled with fluid, typically mixtures of a polymer viscosifier, corrosion inhibitor, and high-concentration salt solution. In cold climates, diesel or crude oil may be used as a "packer fluid" 10 to 50 feet below the surface to prevent freezing. "Packer fluids" may be removed and then replaced during workovers.

Major completion operations, many of which may be undertaken during workovers as well, are described briefly below.

Cementing

Casing is cemented in place both to stabilize the casing and the wellbore (i.e., by holding the casing in place and by preventing cave-ins) and to isolate formations from the wellbore (e.g., fresh water aquifers or intermediate "thief" zones). When casing is to be cemented, the cement is pumped through a special valve at the wellhead down the casing to the bottom of the hole and up the annular space between the bore hole wall and the casing; this can be the surface casing, intermediate casing, or production casing, although only the latter is truly a completion operation.

Wells are typically cemented with Portland cement that is mixed on-site. The amount of cement needed depends on the height and volume of the annular space to be filled and whether the annular space is to be cemented entirely or stage cemented. In some wells, production casing is cemented throughout the entire

depth of the well, several thousand feet. In others, the zone cemented may extend for tens, hundreds, or thousands of feet above the producing formation but not reach the surface. When the entire length of production casing is to be cemented (and when surface casing is being set), small amounts of cement (and associated additives) may be forced out of the well (i.e., up through the annulus) by the cement operation.

Various additives may be added to cement, and the types and amounts depend on the conditions encountered at the well. Additives include accelerators to promote setting of the cement; these are often used in cementing low-temperature shallower casings simply to save time. Retarders may be added to delay cement setting; this is important for deep wells, where longer pumping times are necessary before cement reaches the zone of interest and where higher temperatures may tend to accelerate cement setting. Additives also may be added to reduce fluid loss to the formation since cement filtrate can form unstable solutions when they react with formation fluids; this can result in precipitation of solids that then block flow paths for hydrocarbons. These and other additives also are added to compensate for temperature, salt water conditions, and other well-specific factors (see also section 1.2.5).

In most completion and workover operations, various types of fluids or materials may be in the well at any one time. In the case of cementing, drilling muds may be in the well; before the cement is pumped down the well, brines or other fluids are pumped to separate the cement and mud and to wash or otherwise remove "mudcake" from the wellbore walls. This not only repairs shallow damage to the formation but also enhances cement adherence. In addition, one or more of the fluids may contain bridging agents that intentionally seal off all or part of a formation in order to prevent filtrate or solids in the cement slurry from entering the formation. The cement is generally followed by water or other fluids that force the cement out of the casing and up the annulus, then by other fluids that perform other completion functions (see section 1.2.4).

Perforation

Unless the completion is open hole, the production casing and cement must be perforated to provide a path for formation fluids to enter the wellbore. Usually, perforating occurs before production tubing is run, but occasionally the tubing is perforated, as well as the casing and cement. Jet and bullet perforations are the methods typically used. Cost, casing size, formation fluids, formation lithology, cementing procedure, pressure, temperature, and other factors are all considered in selecting which perforation technique is used in a particular case.

Both methods require that an explosive-equipped tool be lowered into the wellbore on a wireline and detonated electrically. Bullet perforating simply involves shooting projectiles, usually metal, from a multi-barreled gun through the casing and cement and up to several feet into the formation. Jet perforations require setting off shaped charges next to the casing, which when detonated blow high-speed jets of combustion products in narrow patterns through the casing and cement into the formation. During

perforating (as well as during most other completion and workover operations), the pressure exerted by the fluid within the casing is generally kept sufficiently high so that it exceeds the formation pressure. As a result, no formation fluids can enter the casing until the operator is ready for the well to begin production.

Swabbing

Unless formation pressure is high enough to drive fluids to the surface, the well must be swabbed to remove completion fluids and allow production. Wells may also be swabbed to remove fluids if they could damage production equipment. Fluids inside the well bore are swabbed by a cylindrical rubber cup lowered on a cable through the tubing strings. When raised, the cup expands against the tubing and "swabs" the fluids up the wellbore. Swabbing may also be used following workover operations to remove fluids before a production or injection well is put back in operation.

Sand Exclusion and Removal

In some formations, particularly less consolidated sandstones, sand can present major problems during a well's life. When produced with oil and brines, it can damage or shorten the lives of pumps and other production equipment as well as clog formations and downhole equipment. It also results in a waste that must be disposed or otherwise managed. A number of techniques and operations are used to reduce or minimize sand problems, and they can be implemented during completions, workovers, or both.

Sand or gravel packing is a common practice to reduce the amount of sand that is produced. Gravel packing is generally achieved in two steps. The first step, not used in open-hole completions, involves pumping graded sand (whose size is larger than formation particles), typically in a slurry thickened with gelling agents, through the perforated casing and cement into the formation until the area outside the casing near the wellbore is packed. Then, a slotted, perforated, or screen liner is placed in the well below the production tubing. Next, the sand slurry is pumped through a crossover to fill the annular space between the casing and the liner. The sand/gravel pack stops formation solids but not fluids and the liner then stops the sand from entering the wellbore. If a gelled fluid is used, it is intended to disintegrate over time and leave only the sand. Similar sand or gravel packs and liners may be used in open hole completions by packing sand or gravel and lining the uncased formation interval. Over time, liner slots may be enlarged by the abrasive action of the produced fluids and more and more sand can enter the well. In such cases, the liner may be removed and replaced during workovers.

Other methods of sand control include cementing fine particles near the wellbore with resins pumped down the well. These resins consolidate near-well sand particles in place and prevent their movement into the well. Operators also may install pre-packed liners, in which case resin-bound sand or other filter media is pre-packed in a liner-tubing assembly; this type of sand exclusion may be particularly effective in horizontal wells (Zaleski 1991).

Sand removal, which may be necessary at completion and during a well's production life, is generally accomplished by flushing or bailing. Flushing involves circulating a fluid with sufficient solids-lifting properties (e.g., gelled water, foam, oil) down the tubing and up the tubing-casing annulus, carrying entrained sand. (During workovers, small-diameter macaroni tubing may be run down the production tubing and the sand circulated out the macaroni tubing-production tubing annulus. This avoids the necessity of unseating and then reseating packers, and is necessary in permanently completed wells.) Bailers are long cylindrical containers that are lowered to the bottom of the well on a wire rope (a "sand line"). A valve on the lower end closes when the bailer reaches bottom and is lifted. The bailer and sand are then raised to the surface. Sand may be removed from wells as a single operation but more commonly its removal occurs in conjunction with other operations. Sand may be bailed or flushed before well treatments or stimulation so that treatment fluids do not drive the sand into the formation; following treatment, sand may be removed before the well is placed in production or injection.

Artificial lift

Formation pressure in most oil fields in the United States is not sufficient to drive formation fluids all the way to the surface and allow wells to produce naturally. In such cases, which amounted to over 94 percent of producing oil wells in 1985 and 95 percent in 1990 (API 1992a), artificial lift equipment is installed. Gas lift and various types of pumps are the most common means of providing artificial lift.

If gas is economically available, it is injected down the annulus and through valves in the production tubing. It aerates the fluids in the tubing, thereby lightening the fluids and allowing them to rise under existing pressures. If pumping is necessary, sucker rod pumps or, less frequently, hydraulic or electric pumps are installed to pump fluids to the surface. A pumping unit raises and lowers a valved downhole pump plunger attached to the sucker rod string. When the pump plunger begins to rise, formation fluids are pulled into the pump barrel (this creates a pressure differential which "sucks" fluids from the producing zone into the wellbore). Hydraulic or electric pumps are placed in the bottom of the tubing and simply pump fluids upward to the surface.

1.2.2 Workover Operations

During the life of an oil or gas producing well or injection well, a variety of maintenance and remedial operations are performed. These may include replacing corroded or stuck tubing and downhole equipment, removing and/or inhibiting paraffin or scale accumulation, squeeze cementing, well stimulation, and a variety of other operations.

During workover operations, a well may require "killing" to control formation pressure. In such cases, the first fluid (brine, oil, or other) pumped down the well is of sufficient weight to stop the flow of production fluids from the formation into the well. During any subsequent workover operations, formation pressure continues to be controlled by pressures exerted by whatever fluids are in the wellbore.

Removing/Inhibiting Paraffin and Scale

The heaviest hydrocarbons in produced fluids can solidify at certain temperatures and pressures or when exposed to certain chemicals. When solidified, these hydrocarbons (*e.g.*, paraffin) can accumulate and block pores in the reservoir, block or partially block production tubing, and interfere with production equipment. The effect of downhole blockage is to reduce the area through which produced fluids can flow, thus reducing production or requiring ever-greater pumping pressures. In addition to treatments whose sole purpose is paraffin removal, it may be necessary to remove paraffin before other well treatments are performed. For example, treatments solely for paraffin removal may be necessary when paraffin accumulations have severely restricted flow in the well. Paraffin removal prior to other well treatments is performed both to avoid having other treatment fluids incidentally remove paraffin and transport it into the formation, where it can clog flow channels, and to ensure that accumulations of paraffin do not interfere with efficient movement and distribution of treatment fluids (*e.g.*, by clogging perforations). Whether paraffin removal is the only workover operation performed or a preliminary treatment, the methods used to remove accumulations are the same.

The removal of paraffin in tubing can be as simple as running a mechanical scratcher or scraper down the tubing. Hot liquids, either oil or water, also are circulated downhole to melt paraffin accumulations and return the melted paraffin to the surface. Paraffin also can be removed with chemical treatments: xylene, toluene, and other aromatic compounds may be the most effective (and most costly); kerosene and diesel also are used. In addition, a variety of other chemical additives are effective in removing paraffin accumulations (see section 1.2.5).

Salts and other materials also may accumulate in formations, on tubing, and on production equipment, blocking or partially blocking flow. Such scale deposits can be the result of various chemical reactions, including: reactions between produced fluids and downhole tubing and equipment; between produced fluids and chemicals used in well treatments; between different chemicals used in well treatments; and various combinations of these and other reactions. In sour-gas fields, scales composed of iron compounds may be particularly troublesome. As with paraffin accumulation, operations may be designed specifically to remove scale or may be part of a larger treatment. Hydrochloric and other acids used in acidizing wells (see below) are effective scalants. If scale is not removed before acidizing agents are pumped down the well, the pumped acids may partially spend themselves on scale deposits and also may leave scale in the formation. Many acidizing treatments are thus preceded by a stage in which a scale-removing fluid is circulated through the well (see section 1.2.3 below).

Overall, the most common types of scale are calcium carbonate, calcium sulfate, magnesium sulfate, and barium sulfate. Hydrochloric acid is effective in removing some scales, and other acids are used for this and other types of scale deposits (*e.g.*, ethylene diamine tetraacetic acid--EDTA--for calcium sulfate or iron scales). In addition, scale inhibitors may be used in treatment fluids to remove scale and/or to reduce scale accumulation. Acids or fluids containing scale inhibitors are simply pumped down the well and allowed time to dissolve the salts; then another fluid, often water, is used to flush out the fluid and dissolved scale

(as noted, often this is a stage in an acidizing or other stimulation operation). Some inhibitors also are effective in leaving a scale-resistant coating on tubing and downhole equipment. Finally, inhibitors may be added to fracturing fluids pumped under pressure into the formation. Small amounts of the chemical(s) then remain in the formation and, for at least a short time after the treatment, mix with formation fluids as they move toward the wellbore.

Inhibiting corrosion

Harsh subsurface environments make corrosion of tubing, casing, and downhole equipment a common problem. Both sulfur and formation water are corrosive, as are acids and other chemicals used in well treatments. To prevent or reduce corrosion, a variety of chemicals are used (during completion, workover, and well stimulation operations) to coat downhole metal (e.g., tubing) with a layer of corrosion-resistant material. When acids are to be pumped down the well to remove scale or to treat the formation, they may contain inhibitors or retarders that interfere with and/or delay corrosive reactions, and they often are preceded by fluids containing corrosion inhibitors that coat the tubing. Similarly, fluids that follow acids generally contain inhibitors. Where packer fluids are used, they generally contain corrosion inhibitors to protect the production casing and the outside of the tubing from corrosion.

Cleaning

During the course of a well's life, materials may be dropped down the well and formation rock may fall into open holes. Similarly, formation sand may require periodic removal. In addition, pipe or tools may simply become stuck in the wellbore. As a result, the well may be cleaned out, with the tools and techniques used (and wastes generated, if any) dependent on the specific case.

Sand removal is generally accomplished as described previously. Retrieval of objects and material from wells may require bailing or "fishing" operations. Bailers are used to remove small unconsolidated debris from the wellbore. Removal of larger objects can require the use of specialized fishing tools such as "junk baskets," magnets, spears, overshots, or a variety of other tools. "Jars" (which are used to jar or jerk stuck objects) may also be required. In intractable cases, operators may simply drill or mill through obstructions using specialized bits or mills (in which case the debris is generally removed from the hole by circulation or other mechanical means before the well is placed in production). When these methods fail, the operator will generally drill around the obstruction (sidetrack).

Squeeze Cementing

Squeeze cementing refers to the process of squeezing cement into micro-annuli that result from a poor cement job (e.g., poor mechanical integrity) when casing is cemented in place. It may also be used to plug formations or repair leaking casing. Plugging all or part of a formation may be necessary, for example, if excessive fluids are being lost or if a formation is depleted and the well is to be completed in a higher (or lower) zone. Whatever the reason, it is sometimes necessary to block off the well and plug a formation. First, permanent or retrievable plugs or packers are set below the area to be plugged. The tubing-casing

annulus is then sealed, at the wellhead or with packers set just above the zone of interest. Cement is pumped under pressure (either from pumping rates or from fluids that follow the cement, or both) down the well. The sealed annulus keeps the cement at the proper depth and the pressure forces the cement through the leaking casing--or through the perforations and old cement, if all or part of a perforated zone is to be sealed--and into the formation. If the lower zone is to be plugged back (i.e., permanently closed), cement can fill the wellbore and seal off the lower well. As described above for casing cement, a variety of additives may be used depending on the well's needs.

Other workover operations

A variety of other operations may be performed on a producing well. These may include patching casing (e.g., by attaching "sleeves" to sections of bad casing with epoxy resins), installing liners the entire depth of the well (e.g., if damaged production casing cannot be repaired), and re-opening collapsed or narrowed sections of casing (e.g., using a casing roller, or "swaging" tool, to force open narrow areas). In addition, collapsed casing, unretrievable blockages of the casing (e.g., by stuck tubing, equipment, or tools), or other causes may make a well unrepairable. In such cases, "sidetrack" drilling may make it unnecessary to plug and abandon the entire well. To sidetrack, the well is plugged back some distance above the obstruction. Then a hole is milled through the existing casing above the plugged area and drilling proceeds, typically at shallow angles of about two degrees. Once the diverted hole reaches a sufficient distance from the damaged well, the angle of drilling slowly regains the vertical and the drilling continues to the formation of interest. When the sidetracked hole reaches the formation, it is completed in the same manner as the original well (i.e., installation of production casing, etc.).

Finally, wells may be deepened as part of workover operations. This may involve drilling to a new producing zone (e.g., in a developed field where it is known there is such a lower zone) or, more commonly, to clean out the bottom of the well. If deepening to a new zone, the old producing zone may be plugged by squeeze cementing, then the well can be drilled to the new depth, the lower casing installed, and the well "re-completed."

1.2.3 Well Treatment and Stimulation

Well stimulation treatments include a number of methods to increase the permeability of the fluid-bearing stratum and initiate, restore, or improve recovery of hydrocarbons from the reservoir. The density of many formations is such that there is insufficient pore space or fractures to allow production without some treatment. In addition, formations can be damaged when particles (formation sand, drilling mud solids, other fluids solids, scale, paraffin, etc.) block channels and pores and thus hinder or block the flow of produced fluids. When these conditions occur, which can be at the time of a well's initial completion and periodically during its producing life, one or more stimulation techniques are used to initiate or enhance production. Two basic methods are used for well stimulation or treatments: hydraulic fracturing, and acidizing (or "etching"). The purpose of these stimulation techniques is to create, extend, enlarge, and/or open channels through which hydrocarbons can migrate to the well.

For any individual well, the stimulation method selected depends primarily on the characteristics of the well and the formation (e.g., type of rock, depth, formation pressure, characteristics of the crude oil and/or gas, and the relative amounts of water and natural gas). The situation-specific nature of well treatment and stimulation cannot be overemphasized. Explosives were the treatment method initially used to fracture wells. Treatment methods have evolved over time, with the development and widespread use first of acidizing, then of hydraulic fracturing. These have continually been refined, based on an increasing (but still not complete) knowledge of reservoir and well behavior, both generally (e.g., knowledge of fluid movement in sandstone) and specifically (e.g., properties of a specific reservoir). The increasing knowledge has underlined the fact that well-designed treatments have to be adapted to the particular circumstances at hand, and may not be transferable to other circumstances. Similarly, as knowledge of a given reservoir increases over time, so too does the ability to design well treatments that provide optimum return.

Hydraulic fracturing and acid stimulation methods are described below. Although rarely, if ever, used today, explosive fracturing is also described. This discussion helps to underscore the phenomenal evolution of fracturing and stimulation technology during the past seventy years.

Explosive Fracturing

Development of hydraulic fracturing and acid treatment in the 1930s and 1940s all but eliminated the former widespread use of explosives to fracture formations and stimulate wells. However, some formations may not be particularly amenable to hydraulic fracturing or acidizing techniques. In addition, some earlier wells that were stimulated with explosives have remained in production longer than fractured and acidized wells. As a result, there has been renewed interest in stimulation by explosives. In general, this type of stimulation involves the use of explosives (e.g., nitroglycerine or plastic explosives) to enlarge the well hole and fracture the surrounding formation, creating paths along which hydrocarbons migrate to the well bore.

The broken rock created by the explosion serves to keep the fractures open.

One method of explosive stimulation increases the well hole size by detonation in the borehole in the producing zone. A second method involves injecting explosives into fissures and voids away from the bore hole, which increases the size of the fractured zone. Other things being equal, a larger explosion results in larger and longer fractures.

Of historical interest are two tests of stimulation by nuclear explosion, in which underground nuclear devices were used to fracture low-permeability gas-bearing formations in New Mexico (a 26 kiloton device exploded in 1967 in Rio Arriba County in the San Juan Basin) and Colorado (a 40 kiloton device exploded in 1969 in Garfield County, forty miles northeast of Grand Junction). Both tests were apparently effective in stimulating production, but the cost of the devices (\$350,000 for a small one, \$600,000 for a large) was described as restricting their use (Howard and Fast 1970).

Acidizing

Acid stimulation involves introducing an acid solution to the formation. The acid dissolves the rock, thus creating or enlarging flow path openings. Formations composed of carbonate rock (e.g., limestone or dolomite), or with carbonate cementing agents, are the types most amenable to acid stimulation. *Acid fracturing* combines fracturing and acidizing. *Matrix acidizing* avoids fracturing the formation by pumping at lower pressures. In addition, acids can be used to repair damage to formations caused by drilling or other operations. For example, they are often used to dissolve clays (from muds or from the formation) or precipitated solids from cement or mud filtrate that may have clogged near-well pores. They also are used for scale removal and other purposes, either in conjunction with acidizing or fracturing or as a specific treatment.

Hydrochloric acid (HCl) is the most widely used (and cheapest) acid, and is typically used at concentrations of 15 to 28 percent by weight. It is most effective in treating carbonates, either in carbonate rock formations or clastic formations where carbonates are the cementing agent. Hydrochloric acid is less effective on clastic rock, whose sands, shale, clays, or anhydrites are only partially soluble in hydrochloric acid and which are readily precipitated. Hydrofluoric (HF) acid is more effective on the latter. Often used in sandstone and other clastic formations are mixtures of hydrochloric and hydrofluoric acids; such "mud acids" (commonly 12 percent HCl and 3 percent HF) were originally used to treat problems caused by mudcake but have been found also to be effective in some sandstone and other reservoirs. Other acids used include acetic and formic acids, often in mixtures, particularly where high temperatures or other conditions make other acids less effective or desirable. Both are more easily inhibited but are not as strong as hydrochloric.

Matrix acidizing is generally effective only for a short distance from the well, and is used in exploratory wells to gain knowledge about the production potential of the new reservoir and in workovers and completions to repair near-well formation damage (by drilling or by prior treatments). In matrix acidizing, the acid is pumped down the well at near formation pressures and allowed to work the face of the formation and near-well pores. In addition, bridging agents or diverters may be used to close off existing flow channels and divert acid to other areas where new ones can be formed or enlarged. Acid fracturing, by combining fracturing and acidizing, not only creates fractures but also "etches" grooves into the rock matrix. These etched channels may be smaller than where proppants can penetrate and acid-etched channels on the face of a fracture may remain open even when the fracture itself closes.

Acid treatments must be carefully managed to avoid several common problems. After contacting the formation, acid is rapidly spent (i.e., the pH rises). Within a relatively short time (generally several hours), as the acid is spent, materials dissolved and held in solution may begin to precipitate and clog the new pores. Thus, acid treatments must be carefully timed, and chemical additives that aid in keeping materials in solution may be necessary. In addition, acids attack the steel in tubing and downhole equipment, which can cause severe corrosion in a short time. This must be prevented by the use of corrosion inhibitors that slow or prevent either contact (by coating the steel) or the reaction between the

acid and steel (organic chemicals that interfere with the reaction). Acids or reaction products can favor the formation of oil-water emulsions or asphaltene sludges; surfactants are used to alter the surface tension of oil and water and reduce the tendency to emulsify and solvents can reduce sludge accumulation. For economic reasons, acid treatments are designed so the volume of acid used is limited to the amount required to dissolve the carbonate material present in the desired treatment zone. Therefore, when swabbed or produced back to the surface, the treatment fluids are essentially or completely neutralized.

As with hydraulic fracturing, acid fracturing may be accomplished in multiple stages. The first stage, as described above, may be to remove paraffin, scale, or other materials that can interfere with the flow of treatment or formation fluids. Then, there may be alternating stages of acid and other fluids (commonly, gelled water or brine). The gelled water is forced into and coats the faces of fractures; the acid pumped behind it is thus kept away from the formation as long as possible (to avoid spending). The acid, itself gelled, also tends not to make contact with wide expanses of rock, but rather to be forced in narrow channels between the gelled water and the rock face, etching a channel in the rock as it travels. Subsequent alternating stages of gelled water and acid then serve to extend fractures and etched channels. Following the last acid stage, a flush of fluid forces the last of the acid into the fracture. Following the last fluid, the well may be shut in for some time (24 hours or more) to allow the acid sufficient time to work. Following the shut-in period, there may be a "post-flush" of acid or other fluid to dissolve or otherwise remove reaction products. Finally, fluids may be swabbed out of the wellbore or allowed to flow with formation fluids.

Acidizing fluids, as well as the various fluids that precede and follow the acid treatment, may contain a variety of other additives that serve the same functions as when they are added to hydraulic fracturing and other fluids (i.e., gelling agents, gel breakers, surfactants, sequestering agents, corrosion inhibitors, fluid loss additives, etc.). As with other fluids, the choice of which types of fluids and additives are necessary, and the specific ones used, depends on field and well conditions.

Hydraulic Fracturing

The first well hydraulically fractured was in western Kansas in 1947. A gasoline-based napalm gel was the fracturing fluid used. (Howard and Fast 1970) Since that time, hydraulic fracturing has become a common well stimulation technique. Fracturing by hydraulic pressure is achieved by pumping fluids at high pressure (i.e., at high rates) into the well, thereby causing material failure of the rock in the formation of interest (i.e., fractures).

The fractures induced in the formation serve as flow paths for hydrocarbons. Shallow-penetrating fracturing, often accomplished with multiple small batches of fracturing fluid that create numerous shallow fractures, can overcome damage to the wellbore caused by drilling or other operations by creating a flow path through the damaged area. It also is used when water-bearing zones lie close to the producing zone. To obtain deep-penetrating fractures, fluids may be pumped at rates that can cause wellhead pressures to reach and exceed 10,000 pounds per square inch, and the resulting fractures can extend tens or hundreds

of feet from the well. In general, fracturing (and all stimulation methods) extends the drainage area into which fluids can flow. Because the drainage characteristics (as well as other well- and formation-specific factors) are so variable, well-designed fracturing operations are tailored to the specific conditions encountered.

Under the great pressure of the overlying earth, hydraulically-induced fractures tend to "heal" and close, which can stop or seriously slow hydrocarbon movement. Thus, the fractures have to be kept open artificially. This is accomplished by suspending inert materials in the fracturing fluid and carrying them into the fractures; these "proppants" (so known because they "prop" open the fractures) then remain in the fractures and keep them open. Common proppants include graded sand, ground nutshells, aluminum (or "bauxite") spheres, glass or plastic beads, and other materials. To keep proppants in suspension long enough to travel the depth of the well and into the fractures, the fracturing fluid must be sufficiently viscous. Crude oil is used as a fracturing fluid, as is water (or acids) to which viscosifiers have been added. Often, the viscosity of water-based fluids is raised with gels. The fluids may also contain gel breakers, which over several hours, break down the gel and decrease the viscosity.

A fracturing operation often proceeds in stages. The first stage, before the fracturing fluid is pumped down the well under pressure, often involves circulating a fluid (e.g., oil, water or brine, or acid, including additives appropriate to the treatment) to clean out the well and/or the formation. Such "preflushes" may be designed to remove sand, scale, paraffin, particles, and other materials (including the remnants or byproducts of previous treatments). Of particular importance is ensuring that perforations are clear of any type of blockage. Such treatment allows more penetration by the fracturing fluids and also keeps the solid materials from being forced into or farther into the formation.

Following the first stage, or initially if there is no prior stage, fracturing fluids are pumped down the well under pressure. This stage can consist of alternate batches of proppant-laden and clear fluids (water or brine are the more common fluids, but foam and other fluids also are used) or of one or more stages of proppant-laden fluid. Multiple stages are used to allow proppant first to be transported into fractures and then forced farther into the fracture. The fracturing fluid is often highly viscous, to suspend proppant as well as to keep the fluid in the crack (by retarding fluid loss to the reservoir matrix). As fluid, or batches of fluid, continues to be pumped down the well, proppants of increasing size may be added: smaller proppants enter the initially narrow cracks, then larger proppants enter the enlarging fractures, forcing the smaller ones farther into the narrowing channel. Optimum distribution of proppants in fracturing fluids can be maintained by adding appropriate spacer materials that will later be removed by solvents or by produced fluids. Following the last stage of proppant-carrying fluid (or acid, if acid is the fracturing fluid) may be a "flush" of fluid that serves to push the last of the proppant into the fractures. At this stage in the operation (and possibly several times during the hydraulic fracturing process), the well may be shut in for a time. Finally, there may be a "post-flush" of fluid to dissolve or otherwise remove reaction products. In addition, it may be necessary to complete the cleanout by bailing or drilling, since proppant particles can severely damage production equipment (e.g., pumps). Following all treatments, the remaining fluids may be swabbed out of the wellbore or allowed to flow with formation fluids.

In addition to gels and other viscosifiers, gel breakers, and paraffin and scale inhibitors, other additives are commonly used in various fracturing fluids, particularly in water-based fluids (see section 1.2.5). Additives may include:

- Clay stabilization agents, to prevent water absorption by water-sensitive clays and prevent clays from migrating and blocking flow channels
- Friction reducers, to allow the fluid to be pumped down the well at a greater rate (which increases pumping efficiency and allows a greater pressure to be achieved)
- Fluid loss additives, to reduce the loss of fluids to the formation matrix
- Corrosion inhibitors
- Surfactants, to prevent the formation of viscous oil-water emulsions
- Biocides, to prevent the growth of bacteria
- Dyes or radioactive tracers, to allow logging or swabbing procedures to better determine the effects of the fracturing.

1.2.4 Completion and Workover Fluids

Completion and workover fluids are selected for their ability to control subsurface pressures, maintain the stability of the well, and keep solids in suspension. They must also be compatible with the formation and minimize corrosion to tubing, casing, and downhole equipment. They must be able to perform a variety of superficial formation damage-prevention or -repair functions. Finally, the solids content of fluids is typically managed carefully in order to avoid unnecessary clogging of formation pores. Low-solids fluids are most effective. It is common practice to filter fluids (using diatomaceous earth, sock filters, or other media) before they are pumped into the well, and circulating fluids may be continuously filtered as they are circulated back into the well.

Table 1-1 shows various types of completion and workover fluids and the purposes for which they are intended. As described above, a variety of fluids are used in succession during completions and workovers, including during well stimulations. For example, one or a succession of preflush or "pad fluids" may be pumped down the well ahead of other treatment fluids. These fluids may serve not only to separate the drilling mud or formation fluids from the treatment fluid, but also may initiate corrosion inhibition, unclog formation pores or seal the pores, reduce fluid loss, remove scale or paraffin, or perform a variety of other functions. Following the well treatment, a variety of other fluids may be used to completely remove prior fluids, repair "skin" damage to the formation at the wellbore, protect downhole equipment (e.g., corrosion inhibitors to provide some protection against corrosion by formation fluids), and to clean out sand or other downhole material. As is emphasized in preceding sections, the types of fluids that are used in any completion or workover are selected for their intended functions. Appendix A provides, in a series of tables, a variety of specific well treatments. An examination of these tables emphasizes the variability of

completions and workovers (specifically, well stimulation through fracturing and acidizing) and the evolution of treatments as field characteristics are better understood.

The act of drilling a well, and performing various completion and workover operations, can cause severe skin damage to a producing formation that can severely reduce or prevent the production of oil or gas. Clays in drilling muds can form an impermeable mudcake on the formation's surface; sensitive formation clays can swell or migrate and block flow channels when they contact water, brines, mud or cement filtrate, acids, and completion fluids; solids can precipitate and block channels when filtrates from cement or mud enter the formation and react with formation fluids; gelled fluids used to transport sand or proppants can leave residues that block channels; the formation of oil-water emulsions and sludges that block channels can be caused by the use of certain acids and other chemicals; and a host of other reactions between formation fluids, completion and workover fluids, and the tubing and downhole equipment can cause precipitation of solids, paraffin or scale accumulation, and/or corrosion and other damage to equipment and tubing. As a result, the major purposes of many of the various additives used in completion and workover fluids is simply the prevention, repair, or inhibition of damages caused by the fluids themselves or other additives used in the fluids.

Associated Waste Report:			
Completion and Workover Wastes (U.S. EPA, January 2000)			
TABLE 1-1. Types of Fluids and Components Used in Completion and Workover Operations			
Operation	Type	Components/Additives	Purposes
Well Stimulation	Acidizing	Preflush Solution (Pad)	"Kills" the well by preventing the flow of formation fluids into the well. Prepares well and formation for following fluids.
	Acid Solution	Acidizing agents Corrosion Inhibitors Surfactants Viscosifiers Gels, gel breakers Fluid Loss Control Diverters Friction Reducers	Dissolves rock to create/open flow path for produced fluids. Additives to enhance treatment, protect well and formation, overcome effects of other additives.
	Postflush Solution (Chaser)	Ammonium chloride Corrosion inhibitors Weighting agents Viscosifiers Gels, gel breakers Surfactants	Forces acid further into formation, then well may be shut in for 12-24 hours or longer. Prepare well for production: clean out, repair damage to formation.

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)				
TABLE 1-1. Types of Fluids and Components Used in Completion and Workover Operations				
Operation	Type	Components/Additives	Purposes	
	Fracturing	Hydraulic Fracturing	<p>Fluids: Water (fresh or brine) Liquid Carbon dioxide Liquid Nitrogen Crude Oil Kerosene Foam Invert emulsions</p> <p>Additives: Proppants Gels Polymers Friction reducers Surfactants Biocides Defoamers Fluid loss Lost circulation</p>	<p>Pump fluids at high rate/pressure to fracture formation rock, increase flow of hydrocarbons.</p> <p>Preceded by pad fluid to prepare well/formation for fracturing: remove scale/paraffin, isolate formations, stabilize clays, etc.</p> <p>May be followed by postflush solutions to force fracturing fluid/proppant into formation, then prepare well for production by cleaning out, repairing damage.</p>
		Acid Fracturing	See Acidizing, Hydraulic Fracturing	Etch flow channels in formation rock as well as fracture
Completion and Workover Operations in General (Also may use pad and chaser solutions)	Water-based	Filtered formation water Prepared brines Weighted water	<p>Viscosifiers Corrosion Inhibitors Bridging agents Fluid loss control Biocides Defoamers Surfactants Weighting agents Lost circulation Dispersants Scale Inhibitor pH Buffer Flocculant Paraffin removers/inhibitors Antiscalant agents</p>	<p>Control pressure during operation</p> <p>Operations: Install/reinstall production string and tubing Cement casing Perforate/re-perforate Install/repair/replace packers Sand/gravel pack Sand cleanout Scale removal Replace/repair tubing/casing Replace/repair downhole equipment Squeeze cement Repair formation damage (mud acid, flush, etc.) Swab Stimulate (acid or fracture) Remove paraffin Remove scale Plug back formation</p>
		Modified or Specially Designed Drilling Fluids		

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Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)				
TABLE 1-1. Types of Fluids and Components Used in Completion and Workover Operations				
Operation	Type		Components/Additives	Purposes
	Oil-based	True Oil Fluids:	Viscosifiers Bridging agents Fluid loss control	
		Crude oil Diesel Refined fuel oil	Biocides Defoamers Surfactants Weighting agents Lost circulation	
	Oil-based drilling fluids (modified/ designed)	Dispersants Scale Inhibitors pH Buffer Flocculent Paraffin removers/inhibitors		
		Invert Emulsion Fluids: Water in oil (up to 50 percent)	Viscosifiers Bridging agents Fluid loss control Biocides Defoamers Also see above	
	Packer		See above	Seal annular space between casing and production tubing to prevent formation fluids from reaching the surface; protect casing and tubing from corrosion, etc.
Sources: Many references.				

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1.2.5 Materials and Chemicals Used in Completion And Workover Fluids

As the foregoing discussion indicated, a wide variety of treatment chemicals are added to completion and workover fluids to enhance the fluid's ability to accomplish its function and to reduce or mitigate operating problems. These chemicals range from relatively simple inorganic compounds to complex organic polymers for which the chemical structure is incompletely understood (Cottle et al. 1990). While some natural additives are still used in large quantities (e.g., barite and bentonite), the trend in the development of oilfield chemical additives is toward the replacement of many natural clays previously used with natural and synthetic polymers.

Obtaining information on the composition of particular completion or workover fluids used at specific sites is not straightforward or easy: even where product names are known, the amount and characteristics of the various additives can vary from completion or workover operation to operation, from well to well, and from day to day, depending on the particular problems encountered.

Even if the primary constituents of completion and workover fluids could be ascertained, the possibility exists that the additives may contain contaminants. According to Hudgins (1991), virtually all oilfield treatment chemicals are complex mixtures manufactured from impure, raw materials. Partially because of this, many different molecular compounds of similar chemical and/or biological activity may exist in a batch of reaction product. While the different compounds may not hinder the effect of the chemical treatment, it makes it all the more difficult to identify the exact constituents. Chemicals also may be altered in the treatment process itself, through chemical reaction and heat, resulting in complex secondary mixtures (Cottle et al. 1990).

Finally, a major difficulty in compiling a complete list of additives used in completion and workover fluids stems from the proprietary nature of the chemical business. It is very difficult to assess the concentrations or toxicities of various additives since the chemical formulations are so variable.

The complexity of completion and workover fluids is reflected in the types and numbers of additives that may be added to fluids to accomplish specific functions and in the number of chemicals that may be used as additives. Table 1-2 lists various types of additives and specific chemicals that may be used. It is by no means a comprehensive list, but it does illustrate various additives and chemicals that may be used and gives a flavor of the complexity of completion and workover operations. It should be noted that these additives (other than acids used in acid stimulation perhaps) are not unique to completion and workover operations: many or most may be used in drilling fluids as well. Several of the major agents and additives not discussed previously are described below.

Surfactants

Surfactants consist of a variety of chemicals that prevent formation of oil-water emulsions or precipitates. These additives are used in small amounts to help disperse poorly-soluble components of formation and

completion and workover fluids. Surfactants function by adsorbing on surfaces and at interfaces and decreasing surface tension. Surfactants have many purposes and include chemicals classified as other additives such as emulsifiers, foamers, and defoamers. In addition, surfactants can be used to aid in mitigating corrosion and bacterial problems. The surfactants may supplement the detergent properties of corrosion inhibitors and biocides to allow those compounds to penetrate metal surfaces and may also help dislodge deposits from the tubing (Hudgins 1991). The additives differ depending on the type of fluid (i.e., water-based or oil-based). Some of the more common chemicals used include alkylaryl sulfonates, alkylaryl sulfates, and fatty acid derivatives.

Corrosion Inhibitors

Corrosion can severely damage or destroy well casing and tubing and other downhole metal. Other than that resulting from introduced acids during workover and completion operations, corrosion is caused primarily by the presence of dissolved oxygen and acidic gases (such as hydrogen sulfide and carbon dioxide). A natural source of corrosion is the brine composition typically present in produced water. In addition, the use of brine fluids in treatments can pose a serious corrosion problem (Acosta 1981).

Corrosion inhibitors are one means to minimize internal damage to equipment. Corrosion inhibitors are organic compounds added to completion and workover fluids to prevent or reduce corrosion by forming protective layers on metal surfaces. Corrosion inhibitors are also used for regular ongoing treatment in some wells. They temporarily adsorb onto metal surfaces and can reduce corrosion rates by more than 90 percent (Hudgins 1991). The most commonly used compounds are amides/imidiazolines, amines or amine salts, quaternary amines, and heterocyclic amines. Oil-soluble inhibitors are generally preferred for oil production because of their greater effectiveness.

(text continues on page 30)

<p align="center">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 1-2. Materials and Additives Used in Completion and Workover Operations</p>		
Component	Function	Examples of Additives
Cement ¹	Complete well, install casing, isolate formations, plug back	Portland cement slurry Additives: Accelerators Retarders Fluid loss additives Dispersants
Acidizing agents ¹	Increase formation flow	Hydrochloric acid Hydrofluoric acid Acetic acid Formic acid EDTA Mud acid: mixture of HCl and HF
Fracturing media (proppants) ¹	Keep fractures open	Sand Glass beads Nutshells Metals Plastic beads Aluminum salt of phosphate ether ^B Bauxite ^A Resin-coated sand ^A Zirconium ^A

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Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)		
TABLE 1-2. Materials and Additives Used in Completion and Workover Operations		
Component	Function	Examples of Additives
Surfactants ¹	Prevent formation of emulsions or precipitate; disperse solid particles	Lignosulfonates ^F Calcium lignosulfonate ^F Chrome lignosulfonate ^F Chrome free lignosulfonate ^F Sulfonates ^{A C} Ethanolamines ^C Quaternary ammonium compounds ^{A C} Polyoxyethylated alcohol Alkyl phenols Lignite ^C Modified chrome lignite ^F Causticized lignite ^G Quebracho ^{C F G} Monobutyl ether Polyacrylate ^C Amines ^A Alcohol ether sulfates ^A Fatty alcohols ^A Isopropanol ^A Methanol ^A Oxyalkylated phenols ^A Petroleum naphtha ^A Glycols ^A Sodium tetraphosphate ^G Sodium pyrophosphate ^G Substituted benzoate ^H 4-allyldihydroxybenzene ^H 2,4-dinitro-1,3-dihydroxybenzene ^H Polyethoxylated alkyl phenols ^H Sodium dihydroxynaphthalene sulfonate 1-nitro-2-hydroxy-3,6-disulfonnaphthalene 2-ethyl hexanol Aluminum stearate 2,4-dihydroxyacetophenone ^H 1,3-dihydroxy-2-propanone ^H Monoisobutyrate Quaternary ammonium compounds Octadecyl dimethyl ammonium chloride Alkyl di(2-hydroxyethyl) benzyl ammonium chloride Perfluorooctylsulfonamide isopropyl trimethyl ammonium iodide Oleic acid and hydroxyethyl acetamide ^H Taurates ^L Fatty acids ^L

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)		
TABLE 1-2. Materials and Additives Used in Completion and Workover Operations		
Component	Function	Examples of Additives
Corrosion inhibitors ¹	Prevent or inhibit corrosion of tubing and equipment by formation and treatment fluids, particularly acids	Primary/polysubstituted monoamines and polyamines ^C Long-chain aliphatic diamines ^C Long-carbon-chain imidiazolines ^C Organic sulfophosphate ^C Quaternary ammonium compounds ^C 2-Butoxyethanol ^A 4-4' Methylene dianiline ^A Acetylenic alcohols ^A Amine formulations ^A Ammonium bisulfite ^{A B F} Gelatin ^A Ironite sponge ^A Sodium chromate ^{A B} Sodium dichromate ^A Polyacrylate ^F Sodium polyacrylate ^A Zinc compounds ^{F J} Zinc carbonate ^{A B} Zinc lignosulfate ^{A B} Zinc oxide ^A Zinc chromate ^B Substituted pyridines ^B Quaternary polyvinyl heterocyclics ^B 1-methyl-2-propyl-3,5-diethyl pyridinium acetate 4-vinyl pyridine Quinoline Pyrazine Acylated hydroxyalkyl amino-alkyl amides ^B Nitrogen ^B Morpholine polyethoxyethanol ^B Triethanolamine esters of linoleic acid ^H Arsenic compounds ^L
Paraffin remover and inhibitor ¹	Remove accumulations of paraffin	Vinyl polymers ^K Sulfonate salts ^K Alkyl polyethers ^K Aryl polyethers ^K Aromatic solvents ^M Xylene Toluene Kerosene Diesel Hot oil, water, or other fluid ^M

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)		
TABLE 1-2. Materials and Additives Used in Completion and Workover Operations		
Component	Function	Examples of Additives
Biocides ¹	Inhibit growth of microorganisms	Chlorine or chlorine releasers ^C Sodium hypochlorite Chloramines Chlorinated guanidines Phenols ^C Halogenated phenols ^C Dichloroxylenol ^C Benzyl cresol ^C Organometallics ^C Oxidants ^C Peroxide Aldehydes ^C Formaldehyde ^C Glutaraldehyde ^{C K} Paraformaldehyde ^C Quaternary ammonium compounds ^C Trimethyl alkyl ammonium chloride ^C Phosphate Decanol Dibutyltin bis(didecyldithiophosphate) Polyisobutylene Acrylate-acrylamide copolymer Vinyl-maleic copolymer Amine sulfonates and sulfates Acrolein (Kissel, 1984) Isopropanol ^A Thiozolin ^A
Detergents ¹ /Foamers	See Surfactants	See Surfactants
Defoamers ¹	Deactivate surface-active ingredients; reduce foaming action, particularly in brackish fluids ¹	Phosphate esters ^C (metallic soaps of fatty acids) Organic silicone compounds ^{A C} Dimethyl silicone Aluminum stearate ^{A J} Ester alcohols ^J Fatty alkanolamides Calcium petroleum sulfonate 2-ethyl hexanol ^J Tributyl phosphate ^A

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)		
TABLE 1-2. Materials and Additives Used in Completion and Workover Operations		
Component	Function	Examples of Additives
Viscosifiers ¹ , weighting agents ¹ , and fluid loss additives	Provide fluid viscosity, optimal density, and prevent loss of fluids	Clays ^C Bentonite ^{A F J} Attapulgite ^{F J} Polymers ^C Polyacrylate ^C Polyacrylamide ^C Cellulose ethers ^C Vinyl acetate-maleic anhydride copolymer Olefin-maleic anhydride copolymer ^H Ethylene-maleic anhydride copolymer ^H Ethylene-maleic anhydride diallyl ether polymer ^H Styrene-maleic anhydride copolymer ^H Polyanionic cellulosic polymer ^J Asbestos ^{C H J} (see note) Barites ^{A C F J} Calcium carbonate ^{C F J} Lead sulfite powder ^C Hematite ^{A F J} Xanthum gum ^C Carboxymethyl cellulose ^C Asphalt ^C Starch and lignite ^C Acrylate Paraformaldehyde and sulfide ^H Poly-N-vinyl-N-methyl acetamide ^H Quaternary ammonium salts of starch Quinone forming naphthalenediols ^H Chromium complexes ^H Chromium glutonate Iron complexes ^H Sulfoalkylated tannin ^H Chlorinated lignin Polyethylene glycol Aluminum tri(p-dodecylbenzoate) Vinyl toluene-acrylate copolymer Stearate ^H Fatty alkyl ammonium lignosulfonate ^H Diatomaceous earth ^A Fly ash ^A Ilmenite ^A Pozzolans ^A Organic polymers ^L Silica flour Polyacrylamide Polyvinyl alcohol Polyacrylamide

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Completion and Workover Wastes (U.S. EPA, January 2000)**

TABLE 1-2. Materials and Additives Used in Completion and Workover Operations

Component	Function	Examples of Additives
Lost circulation materials	Prevent loss of liquid from borehole into fractures or openings; prevent loss of cement slurry to the formation	Gilsonite ^C Mica ^{A C J} Diatomite ^H Asbestos ^H (see note) Polyacrylamide ^H Clay-lignite-graphite powdered asphalt ^H Water and oil dispersible oleophilic colloid ^H Quaternary ammonium compounds ^H Wax emulsions ^H Phenolic treated wood or glass fiber ^H Clay, diatomaceous earth, and calcium carbonate ^H Nut shells ^{A J} Cellophane ^{A J} Cane fibers ^A Cedar fibers ^A Corn cob ^A Cottonseed hulls ^A Rock wool ^A
Retarders	Extend cement setting time to allow cement pumping in deep wells	Calcium lignosulfonate ^C Gums ^C Starches ^C Carboxymethyl cellulose ^C Hydroxyethyl cellulose ^C Lignins ^N Sodium chloride (high concentration) ^N See also: Lost Circulation Materials
Accelerators	Speed up cement setting time	Calcium chloride ^{A C} Sodium silicate ^C Gypsum ^A Potassium chloride ^A Sodium chloride ^A Sodium metasilicate ^A Sodium chloride (low concentration) ^N See also: Lost Circulation Materials

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<p style="text-align: center;">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 1-2. Materials and Additives Used in Completion and Workover Operations</p>		
Component	Function	Examples of Additives
Dispersants and Thinners ¹	Improve flow or rheology of cement slurry	Lignosulfonates ^C Chrome lignosulfonate ^J Lignins ^C Acrylimide ^C Aryl alkyl sulfonates ^C Naphthalene condensation products ^C Ethylene glycol Polyacrylates Polyphosphates ^N Sodium tetraphosphate ^J Sodium acid pyrophosphate ^J Sodium chromate Lactones ^N Gluconates ^N
Scale Inhibitors, Removers, Chelating and Sequestering Agents	Inhibit scale formation; remove scale	Ethylenediaminetetraacetic acid (EDTA) ^A Inorganic phosphates ^A Nitrilotriacetic acid (NTA) ^A Organic phosphates ^A Phosphonates ^A Polyacrylate ^A Polyphosphates ^A Disodium maleate ^B Sodium, potassium, or ammonium gluconates (in solution with hydroxide and carbonate) ^B Bicyclic macrocyclic polyether ^B Hydrochloric acid Hydrofluoric acid Lactic acid ^L Acetic acid ^L Gluconic acid ^L Citric acid ^O Aspartic acid ^O Glycolglycerine ^O Hydroxycyclohexyliminodiacetic acid ^O Hydroxyproline ^O Glutamic acid ^O Pyridine ^O 2,6-dicarboxylic acid ^O

US EPA ARCHIVE DOCUMENT

<p style="text-align: center;">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 1-2. Materials and Additives Used in Completion and Workover Operations</p>		
Component	Function	Examples of Additives
Bridging agents, Diverters	Temporarily seals areas so fluids are not lost into the formation; temporarily seals old fractures to allow acid to create new channels	Ground calcium carbonate Sodium chloride Calcium lignosulfonates Particulates (solids, gums, polymers) ^P Sulfamic acid ^P Solid organic acids ^P Benzoic acid Salicylic acid Oil soluble resins ^P Swellable polymers or gums ^P Viscous liquids or gels ^P Guar gum gels ^P Hydroxyethylcellulose gel ^P
pH Buffers	Control the degree of acidity or alkalinity	Calcium hydroxide ^A Potassium hydroxide ^{A J} Soda ash ^A Sodium bicarbonate ^A Sodium carbonate ^{A J} Sodium hydroxide ^{A J} Sodium acetate ^A Sodium diacetate ^A
Flocculants/Filtration control agents	Remove small cuttings, other materials from well	Acrylamide AMPS copolymer ^A Aniline formaldehyde copolymer hydrochlorite ^A Anionic polyacrylamide ^A Causticized leonardite ^A Leonardite ^A Partially hydrolyzed polyacrylamide ^A Polyalkanolamine ester ^A Polyamine acrylate ^A Polyanionic cellulose ^A Potassium lignite ^A Preserved starch ^A Sodium carboxymethyl cellulose ^A Starch ^A Sulfomethylated phenol formaldehyde ^A Vinylsulfonate copolymer ^A Sodium polyacrylate Phosphonates Alkylene diphosphonate Aminomethyl phosphonate Epoxyethane polyphosphonates Ethane diphosphonates Polyoxyethylene ethers of phenol

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)**

TABLE 1-2. Materials and Additives Used in Completion and Workover Operations

Component	Function	Examples of Additives
Friction reducers	Reduce friction between fracturing fluids and pipe and allow greater pumping rate.	Molybdenum complexes ^H Acrylate-acrylamide copolymer ^H Decanol ^H Dibutyltin bis(didecyldithiophosphate) ^H Polyisobutylene ^L Vinyl-maleic copolymer ^H Amine sulfonates and sulfates ^H Sulfurized phenolic compounds ^H Oleic acid and tall oil ^H Organic polymers ^L Guar ^L Polyacrylamide ^L Fatty acids ^L

SOURCES:

- I From "List of Associated Wastes Generated by the Exploration, Development, and Production of Crude Oil and Natural Gas," Unpublished table prepared by EPA, Office of Solid Waste.
- A API (November 1, 1989). American Petroleum Institute Bulletin E1: Bulletin on the Generic Hazardous Chemical List and Inventory for the Oil and Gas Exploration and Production Industry, First Edition.
- B Dryden, F.E. and L.C. Keifer (1983). Industrial Process Profiles to Support PMN Review: Oilfield Chemicals. Walk, Haydel, and Associates, Inc., New Orleans, LA, for EPA, Office of Toxic Substances.
- C Cottle, M.K.W. and T.L. Guidotti (1990). Process Chemicals in the Oil and Gas Industry: Potential Occupational Hazards, Toxicology, and Industrial Health, 6:41-56.
- D ERT (May 1988). Exploration and Production Industry Associated Wastes Report, prepared for American Petroleum Institute.
- E EPA (March 1991). Development document for [Proposed] Effluent Guidelines and Standards for the Offshore Subcategory of the Oil and Gas Point Source Category, EPA/440/1-91/055.
- F Leuterman, A.J.J, F.V. Jones, G.W. Bettge, and C.L. Stark (July 1989). New Drilling Fluid Additive Toxicity Data Developed, Offshore.
- G Jones, F.V., C.M. Moffitt, W. Bettge, R. Garrison, and A.J.J. Leuterman (November 24, 1986). Drilling Fluids Firms Respond to EPA Toxicity Concerns, Oil and Gas Journal.
- H Ranney, M.W. (1973). Drilling Mud and Fluid Additives, Noyes Data Corporation, Park Ridge, NJ, pp 305.
- I World Oil's 1987 Guide to Drilling, Completion, and Workover Fluids.
- J National Academy of Science (1983). Drilling Discharges in the Marine Environment, NAS Press, Washington, DC.
- K Hudgins, C.M. Jr. (1991). Chemical Treatments and Usage in Offshore Oil and Gas Production Systems, presented at the 23rd Annual Offshore Technology Conference in Houston, TX, May 6-9, 1991.
- L Williams, (1979).
- M Skinner, D.R. (1981). Introduction to Petroleum Production, Vol.I, Drilling, Well Completion, Reservoir Engineering, Gulf Publishing Co., Houston.
- N Rike (1973)
- O Walker (1991)
- P Crowe (1971)

Note: It is believed that asbestos is no longer used as an oilfield fluid additive.

Paraffin Solvents, Dispersants and Inhibitors

Produced fluid can become unstable after it leaves the formation, and decreased pressure and temperature can cause solid hydrocarbons to deposit on the tubing and other downhole surfaces. The deposits can severely restrict or completely block the flow of hydrocarbons. The composition of the solid depends on the original oil composition, but is generally referred to as paraffin. Chemical methods of removal are used in conjunction with physical ones such as scraping or the circulation of hot oil that simply melts the paraffin.

In addition, solvents, dispersants, and inhibitors are used to control accumulation of solid hydrocarbons. Paraffin solvents are used to remove accumulations of deposits by either dissolving the paraffin or keeping it in solution. Paraffin inhibitors prevent solids from forming or sticking to surfaces where paraffin could accumulate. Vinyl polymers, sulfonate salts, and mixtures of alkyl polyethers and aryl polyethers are the most common. Inhibitors are usually added in the 50-300 ppm range, while the solvents comprise a few percent of the completion and workover fluids (Hudgins 1991).

Biocides

Biocides are generally defined as any chemical material, agent, or substances with the ability to kill living organisms. Biocides are used to inhibit growth of microorganisms such as sulfate-reducing bacteria (that produce hydrogen sulfide), filamentous fungi, or yeasts (that can cause fermentation of completion and workover fluids). Biocides are commonly added to fluids containing starch or polymers that are rapidly degraded by heat, agitation, or microorganisms. Aldehydes, quaternary ammonium compounds, and amine acetate salts are the most common (Hudgins 1991). In addition, many biocides have dual functions because numerous chemical ingredients in biocide products can also be effective as corrosion inhibitors or surfactants.

Defoamers

The use of brine and polymers in completion and workover fluids allow the entrapment of air and gas. The addition of defoamers can reduce both the quantity and stability of the foam by reducing the surface tension of the fluid. Two basic types of defoamers, silicones and polyglycol esters, can be used in either water or oil systems to reduce foam (Hudgins 1991). This permits the release of the entrained air and gas (Acosta 1981).

Viscosifiers, Weighting Agents, and Fluid Loss Preventatives

Viscosifiers, weighting agents, and fluid loss preventatives are included together because many of the same additives may be used for all these functions. For example, clays and polymers can act as viscosifiers, weighting agents, and fluid loss preventatives (National Research Council 1983).

A viscosifier is necessary to make the fluid viscous enough to suspend and carry solid particles from the bottom of the hole to the surface. Additionally, the viscosifier acts to prevent fluid loss by sealing the wellbore. This reduces liquid loss through fractures or cracks in the hole. Viscosifiers and fluid loss additives differ depending on the type of completion and workover fluid (i.e., water-based or oil-based). Although most substances used as viscosifiers are clays or starches, several synthetic chemicals, such as acrylates and acrylamides, are also commonly used.

Fluid loss control in completion and workover fluids may be achieved by using a blend of solids and polymers. The mixture creates an impermeable bridge within the formation pore spaces (Acosta 1981). This impermeable layer prevents the loss of completion and workover fluids and damage to the formation. In completion and workover fluids, any material added to reduce fluid loss must be easily removable, or the blocked pore spaces prevent the flow of formation fluids. (Hudgins 1991).

Close control of subsurface pressures is of prime importance in completion and workover operations. Failure to control pressures can result in major damage to a well, thereby hindering its ability to maintain economic permeabilities (Acosta 1981). Heavy brines or weighting agents perform this function by increasing pressure within the wellbore to control formation fluid flow. Weighting agents are generally of high specific gravity, nonreactive with the liquid phase of the formation fluid, nonabrasive, and of optimal particle size.

Lost Circulation Materials

Lost circulation is a common problem encountered during completion and workover operations. Lost circulation occurs when completion and workover fluids escape into cracks or holes. Lost circulation materials also perform the special function of preventing loss of cement to the formation during completion operations by accelerating or extending the cement setting time. In this special function, the lost circulation materials are referred to as accelerators or retarders, respectively. The function of lost circulation materials is to plug fractures or openings. Lost circulation materials are added to the fluid either as an additive or as a premixed slurry slug (National Research Council 1983). These materials are usually fibrous, filamentous, granular or flaked and are mostly naturally occurring, such as ground nut shells, sawdust, and mica.

Dispersants and Thinners

Dispersants and thinners are used to reduce viscosity. As the completion and workover operations proceed, the oil field fluids have a tendency to thicken. As the completion and workover fluids thicken, they lose their effectiveness in removing solids from the borehole. This creates a need for thinners to disperse the solids, allowing the fluid to flow more easily. Plant tannins, such as quebracho (taken from the oak tree), were the first dispersants, and are still commonly used. Materials commonly used as thinners in water-based fluids are classified as polyphosphates, lignitic materials, and lignosulfonates (National Research Council 1983). In addition, dispersants and thinners may be used to reduce viscosity once intentionally-

"thickened" fluids have performed their function to allow the fluids more easily to be recovered or to enter formation flow.

Scale Inhibitors

In oilfield operations, scale is deposited in the production tubing, casing, screens and liners, and the formation itself. Scale generally forms from a pressure or temperature change in the production or treatment fluid. The scale deposits impede the flow both of production and treatment fluids. In extreme cases, scale formation can result in complete tubing blockage (Dryden and Keifer 1983). Deposition of common oilfield scales such as calcium carbonate and calcium sulfate can be reduced with scale inhibitors. Scale inhibitors control scale deposition by interfering with the growth of crystals (Hudgins 1991). Two basic methods exist for the removal or prevention of scale formation. One is the chemical treatment of the scale to render it acid soluble. The second method uses chelating or sequestering agents (Dryden and Keifer 1983). Three generic chemical types, phosphonates, phosphate wetters, and acrylic-type polymers comprise more than 95 percent of the chemicals being used. A minimum concentration, typically 3-10 ppm, must be present at all times to prevent scale deposition (Hudgins 1991). In addition, hydrochloric acid is effective on some types of scale, and may be used prior to fracturing or acidizing treatments; if it is not removed before the main treatment, the treatment fluids can dissolve the scale and transport it into the formation, where it can then precipitate and clog pores.

pH Buffers

The pH of most water-based fluids (other than acids) may be kept alkaline (*e.g.*, by addition of soda ash) for a variety of reasons. Corrosion control and the control of hydrogen sulfide gas are two of the primary reasons. But other fluid properties, such as the solubility of additives are also affected. Ionic balance is also commonly affected by contamination of the fluid system by cement, salt, or anhydrite (National Research Council 1983).

Flocculants and Filtration Control Agents

Flocculants are used to remove small solids. Thus, they may be used in fluids to clean out wells, particularly after fracturing or acidizing treatments. Acrylic polymers are often used as flocculants and can perform a dual function as filtration control agents (National Research Council 1983).

Friction Reducers

During fracturing operations, fluids are pumped down the well at high rates to ensure that downhole pressure is sufficient to fracture the formation. Friction between the fluid and the pipe can reduce pump efficiency and require substantially more pumping pressure. To overcome this, various additives are added to fluids to reduce fluid-pipe friction.

1.2.6 Frequency of Workovers and Completions

By definition, wells are completed one time, at the time they are placed in production--they also may be recompleted in different formations at any time after original completion. As noted previously, few operations are unique to completion: most or all may be performed one or more times during a well's productive life. API has estimated that wells require workover operations every three to five years (API 1988) and that the average well is treated or otherwise worked over every four years (API 1991).

The Bureau of the Census conducts a census of industries every five years. Among other industries, the Bureau surveys the oil and gas field services industry and reports the number of oil and gas wells that receive acidizing and other chemical treatments and that are hydraulically fractured. Table 1-3 presents the numbers and percentages of producing wells that were treated as reported in each five-year census from 1967 through 1992; Figure 1-1 shows the percentages graphically. As can be seen, the number and percentage of wells stimulated increased steadily through 1982 and then declined substantially, by 41 percent, by 1987 and increased between 1987 and 1992. The increases were likely to have been the result of advances in stimulation techniques that made them more effective and available, together with increasing prices for oil and gas that made treatments economically advantageous; the peak in 1982 coincided with

Associated Waste Report:							
Completion and Workover Wastes (U.S. EPA, January 2000)							
TABLE 1-3. Number and Percentage of Oil and Gas Wells Treated by Acidizing and Other Chemical Treatments and by Hydraulic Fracturing, 1967 - 1992							
Year	Number of producing wells (A)	Acidizing and other chemical treatments		Hydraulic fracturing (A)		Total treatments	
		Number treated (B)	Percent treated	Number treated (B)	Percent treated	Number treated (B)	Percent treated
1967	667,610	27,000	4.0	27,500	4.1	54,500	8.2
1972	629,601	64,700	10.3	24,000	3.8	88,700	14.1
1977	655,052	70,800	10.8	30,000	4.6	100,800	15.4
1982	785,910	101,600	12.9	84,100	10.7	185,700	23.6
1987	864,919	59,100	6.8	49,000	5.7	108,100	12.5
1992	865,574	71,300	8.2	71,200	8.2	142,500	16.5

SOURCES AND NOTES:

A API 1995. Section III, Tables 17 and 18 (onshore and state offshore gas and condensate wells) and Table 18 (on- and off-shore oil wells). U.S. totals of oil wells exclude offshore wells.

B U.S. Department of Commerce 1990 for 1982 and 1987 treatment data, and 1995 for 1987 and 1992 treatment data. Data for prior years are from prior Industry Census reports but for this report were obtained directly from Bureau of the Census.

high oil prices. Presumably, the decline between 1982 and 1987 was related to the lower price of oil and gas. During that time, the increased production that could be gained from treating wells was presumably not worth the cost of the treatment.

Table 1-4 presents data on the numbers and percentages of wells, by State, that were treated by acidizing or hydraulic fracturing in

1985 (see Appendix B table notes for the means by which 1985 treatments were estimated). During that year, nearly one in six wells was acidized or fractured. There seems to be little consistency across the States, however, in the percentages of wells treated.

A number of factors would have some influence on the numbers of completions and workovers performed. The relationship between any of these (except completions, of course) and the level of workover activity is not likely to be linear, but much more complex. Values, for 1985 and 1990, for several of these factors are listed in Table 1-5. It is instructive to note that, with the exception of producing gas wells, all key variables declined substantially from 1985 to 1990.

(text continues on page 37)

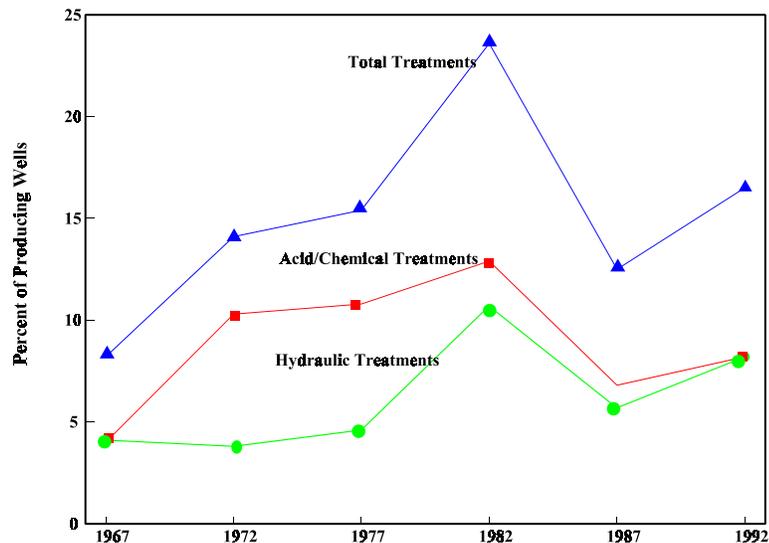


FIGURE 1-1. Percentage of Producing Oil and Gas Wells Treated by Acidizing and Other Chemical Treatments and by Hydraulic Fracturing, 1967 - 1992

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)							
TABLE 1-4. Numbers and Percentages of Oil and Gas Wells Treated by Acidizing and Other Chemical Treatments and by Hydraulic Fracturing, by State, 1985							
State	Number of producing wells (A)	Acidizing and other chemical treatments		Hydraulic fracturing (A)		Total treatments	
		Number treated (B)	Percent treated	Number treated (B)	Percent treated	Number treated (B)	Percent treated
Alabama	1,673	240	14.3	300	17.9	540	32.3
California	51,440	4,840	9.4	3,670	7.1	8,600	16.7
Colorado	9,858	2,000	20.3	1,660	16.8	3,660	37.1
Kansas	67,868	5,540	8.2	1,880	2.8	5,540	8.2
Louisiana	43,070	8,300	19.3	8,180	19.0	16,480	38.3
New Mexico	37,005	3,160	8.5	2,620	7.1	5,780	15.6
North Dakota	3,759	940	25.0	700	18.6	1,640	43.6
Ohio	59,318	1,400	2.4	2,420	4.1	3,820	6.4
Oklahoma	127,098	10,840	8.5	8,460	6.7	19,300	15.2
Texas	253,360	26,860	10.6	20,220	8.0	47,080	18.6
Utah	2,699	820	30.4	860	31.9	1,560	57.8
Wyoming	14,258	2,780	19.5	2,500	17.5	4,820	33.8
Total U.S.	885,643	76,100	8.6	84,100	9.5	139,140	15.7

SOURCES AND NOTES:

A API 1992a. Section III, Tables 17 (onshore and state offshore gas and condensate wells) and Table 18 (on- and off-shore oil wells). U.S total of oil wells excludes 4,327 offshore wells.

B U.S. Department of Commerce, 1990. 1985 figures presented are interpolations of 1982 and 1987 figures provided in source and should be accurate to within ± 50 . See appendix B for 1982 and 1987 data and for means of interpolation.

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 1-5. Changes in Industry Statistics Relevant to Workover and Completion Activity, 1985 - 1990

Measure	1985	1990	Percent change 1985 - 1990
Number of producing wells			
Oil ^A	642,299	583,284	-9.2
Gas ^B	243,344	269,270	
Total	885,643	852,554	
Number of well completions ^C			
Oil	36,458	12,016	-67.0
Gas	12,917	10,187	
Total	49,375	22,203	
Average number of service rigs ^D			
Available	8,006	5,742	-28.3
Active	4,714	3,658	
NOTES:			
A From source 1, Section III, Table 18. Excludes wells in Federal waters.			
B From source 1, Section III, Table 17. Includes natural gas and condensate wells.			
C From source 1, Section III, Tables 1 and 2. Total wells excludes dry holes.			
D Average number of rigs based on monthly totals presented in bimonthly issues of source 2 for 1985 and 1990. It should be noted that the number of active rigs had further declined, to 2,630, by August 1992.			
SOURCES:			
1. American Petroleum Institute. 1992 (May). <i>Basic Petroleum Data Book, Petroleum Industry Statistics</i> , Volume XII, Number 2. Washington, D.C. Data taken from Tables 1 and 2. Total wells excludes dry holes.			
2. <i>Well Servicing</i> (monthly publication of the Association of Oilwell Servicing Contractors) (see note D above).			

2.0 WASTE GENERATION

2.1 WASTES GENERATED

As might be expected from the variety of operations encompassed by completions and workovers, a wide variety of wastes may be generated. Table 2-1 lists workover and completion wastes identified by EPA. To these wastes could be added other types of additives, such as friction reducers, flocculants and filtration control agents, pH buffers, bridging agents and diverters, scale inhibitors/removers, chelating and sequestering agents, and lost circulation materials (see Table 1-2).

As shown in Table 2-1, wastes range from the base fluids (together with additives) and formation fluids to cement that circulates out of the well or that is brought back to the surface (e.g., after drilling temporary plugs). Also included are damaged tubing and pumps and other equipment retrieved from downhole. Among the wastes are several that are generated during exploration and production activities and operations other than completions and workovers. These include the following.

- Produced water is generated during both drilling and production, including during workover and completion operations
- Drilling muds are generated during drilling operations, and various additives may be components of the muds, including during workover and completion operations
- Produced sand settles or is removed from fluids in separation and treatment vessels, tanks, and other places where produced fluids are stored or managed
- Paraffin and scale accumulate in surface piping and equipment as well as downhole
- Used filters are generated during all operations where fluids are filtered

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)	
TABLE 2-1. Wastes Generated by Workover and Completion Operations	
Fluids: Well completion, treatment, and stimulation fluids Muds (water- or oil-based associated with workovers) Produced water (associated with workovers) Crude oil	Components of Fluids (additives): Surfactants Weighting agents/viscosifiers Thinners Acidizing agents Corrosion inhibitors Gels Solvents Paraffin solvents and dispersants Fracturing media Biocides Packing fluids Detergents Defoamers
Non-fluid Wastes: Used filters Paraffin Sludges Pieces of downhole equipment Inert materials from downhole mechanical repair: produced sand, formation or pipe scale, cement cuttings and slurries	
SOURCE: "List of Associated Wastes Generated by the Exploration, Development, and Production of Crude Oil and Natural Gas." Unpublished table prepared by U.S. Environmental Protection Agency, Office of Solid Waste.	

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- Cement cuttings and slurry may be generated during drilling operations (e.g., when surface casing is installed)
- Sludges and emulsions form or accumulate in separation and treatment vessels, tanks, and other places where produced fluids are stored or managed
- Downhole equipment may be retrieved during drilling operations.

Completion and workover fluids may be recovered as wastes when they are circulated out of wells or when they are swabbed or bailed from wells. They may also surface as more or less discrete "slugs" ahead of formation fluids. Depending on the formation and the treatment and over periods that range from hours to days, there may be a transition of fluids from the well: fluids become less and less characteristic of injected fluids and more characteristic of formation fluids. At some point during the transition, fluids would begin to enter production streams as the production fluid component increased.

The means by which the various wastes in Table 2-1 are generated by completion and workover operations are identified in Table 2-2. Other than fluids (and component additives), little or none of the available information bears on the extent to which completion and workover operations contribute to waste volumes or characteristics. Thus, much of the discussion of waste volumes and characteristics in the following subsections, and on waste management in section 3, focusses on the fluid component of completion and workover wastes.

2.2 WASTE QUANTITIES

The only systematic source of information on the quantities of completion and workover fluids that are generated was a survey conducted by the American Petroleum Institute (API 1988). API's methodology is summarized briefly in section 2.2.1 and API estimates are described in section 2.2.2. In an effort to assess API data and/or to estimate rates of generation, section 2.2.3 describes a number of comparisons of API-estimated fluid volumes to a number of other variables. Finally, section 2.2.4 presents limited data on fluid volumes used during completion and workover operations, which could bear on waste quantities.

2.2.1 API Methodology for Estimating Completion and Workover Fluid Generation

The American Petroleum Institute surveyed member companies on their generation and management of drilling, production, and associated wastes in 1985. Among the wastes covered by the associated waste survey were "workover, swabbing, unloading and completion fluids," which were defined to: "include those fluids recovered from a wellbore that are not recombined with the production stream. They include spent acid or stimulation fluids and swab-tank fluids sent directly to disposal. They exclude fluids sent down flow lines, hauled to field batteries, or NPDES permitted pits because these fluids are captured in other waste categories or under water disposal statistics."

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-2. Means by Which Wastes Are Generated by Workover
and Completion Operations**

Waste	How generated
<p>Fluids: Well completion, treatment, and stimulation fluids Muds (water- or oil-based associated with workovers) Produced water (associated with workovers) Crude oil</p>	<p>Base fluids used in completion and workover operations, including treatments and stimulations, and formation fluids produced during and after operations.</p> <ul style="list-style-type: none"> • May be circulated to surface, swabbed or bailed from well, or surface as discrete "slug," transitioning to formation fluids. May be regenerated and reused, reused, or disposed as waste. • May be recovered with formation fluids and enter production lines (separation/treatment vessels, produced water storage/pipelines, and/or production stream).
<p>Fluid additives/components: Surfactants Weighting agents/viscosifiers Thinners Acidizing agents Corrosion inhibitors Gels Solvents Paraffin solvents and dispersants Fracturing media Biocides Packing fluids Detergents Defoamers</p>	<p>Additives that may be in recovered fluids</p>
<p>Solids: Used filters Paraffin, sludges, scale Produced sand Cement cuttings and slurries Pieces of downhole equipment</p>	<p>From filtering fluids to maintain low solids</p> <p>May be recovered as solids during cleanout (e.g., after mechanical removal or flushing) or dissolved or suspended in fluid</p> <p>From flushing or bailing sand cleanout and suspended in recovered fluids</p> <p>From excess slurry circulated to surface, from mechanical or acid removal of excess cement in well, or from drilling through temporary (or accidental) plugs</p> <p>From retrieval of damaged or lost tools or downhole equipment, tubing replacement, etc.</p>
<p>SOURCE: See Table 2-1. Various references for means of generation.</p>	

Only a subset of completion and workover wastes were included in API's survey. API's definition ensures that their estimates do not include at least the following completion and workover wastes, and only for the last of these was an estimate of the volumes generated by completions and workovers found:

- Non-fluid wastes (see Tables 2-1 and 2-2)
- Fluids that may be managed in field batteries or NPDES-permitted pits
- Fluids that are combined with the production stream (presumably fluids that enter produced water lines, separators/treatment vessels, or production pipelines)
- Most importantly, API's reported volumes specifically exclude completion and workover fluids that are injected into on-site underground injection wells (see discussion in section 2.2.2 below).

To extrapolate from survey respondents to all operators in selected States and the United States as a whole, API assumed that within each of those States and for the U.S., the volumes of wastes that were generated (and managed by specific methods) by survey respondents were proportional to the amount of oil produced by the responding companies in the State and the Nation, respectively. This assumption allowed API to estimate the total quantities of wastes generated (and managed) by all operators in those States and the U.S. According to API, at the conclusion of the survey, 53 percent of state crude oil operators had responded. API was careful to note that the statistical estimation of waste volumes assumed that respondents reported accurately and fully. The methodology had a number of other limitations, and several are discussed in sections 2.2.2 and 2.2.4.

2.2.2 API Estimates of Completion and Workover Wastes Generated

Table 2-3 presents API's estimates of the total volumes, of associated wastes in general and completion/workover fluids specifically, that were generated in 1985 (except the wastes noted above). Also presented are the lower and upper confidence intervals for the associated waste estimates--see the table notes for additional notes and qualifications. As can be seen, the confidence levels range from two percent (i.e., generally speaking, the actual volume is 95 percent likely to be within two percent of the estimated volume) in Alaska to 201 percent (i.e., the actual volume could range from 0 to three times the estimated volume) in West Virginia. In general, the narrower confidence intervals are for States where a higher percentage of the States' total oil was produced by respondent companies.

Nationally, API's estimate of completion/workover fluid volume was said to have a 95 percent probability of falling within 20 percent of the reported volume of 5,656,082 barrels; clearly, the estimated volume and the confidence limits rely on the assumptions behind the survey and the extrapolation. (It is not clear if the confidence levels would apply equally to completion and workover fluids, even were all assumptions valid; the estimation method would in no case allow the completion/workover estimates to be more precise than the total associated waste estimates).

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-3. API Estimates of 1985 Generation of Associated Wastes and of Completion and Workover Fluids, and Associated Confidence Levels, 1985

State	Volume of Total Associated Wastes ^a (bbls)			95% confidence levels as percentage of estimated volumes ^c	Workover/Completion Wastes	
	Lower limit ^b	Total wastes	Upper limit ^b		Barrels generated ^d	% of State's associated wastes ^d
Alabama	3,000	8,000	13,000	63	838	10
Alaska	55,000	55,000	56,000	2	5,526	10
Arkansas	10,000	19,000	27,000	42	6,281	33
California	2,174,000	2,379,000	2,584,000	9	124,385	5
Colorado	0	806,000	2,026,000	151	19,381	2
Florida	105,000	163,000	220,000	35	5,400	3
Illinois	0	205,000	441,000	115	3,831	2
Kansas	177,000	290,000	402,000	39	119,325	41
Louisiana	130,000	235,000	340,000	45	45,308	19
Michigan	138,000	161,000	184,000	14	302	0
Mississippi	14,000	50,000	86,000	72	22,494	45
Montana	4,000	337,000	671,000	99	327,115	97
Nebraska	1,000	9,000	18,000	100	1,606	18
New Mexico	193,000	355,000	518,000	46	327,788	92
North Dakota	0	330,000	849,000	157	318,419	96
Oklahoma	1,212,000	2,491,000	3,770,000	51	1,824,092	73
Texas	1,973,000	3,080,000	4,187,000	36	1,931,041	63
Utah	40,000	47,000	55,000	17	5,845	12
West Virginia	0	422,000	1,272,000	201	411,241	97
Wyoming	104,000	150,000	196,000	31	76,137	51
Total U.S. ^e	9,357,000	11,759,000	14,161,000	20	5,656,082	48

(continued)

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-3. API Estimates of 1985 Generation of Associated Wastes and of Completion and Workover Fluids, and Associated Confidence Levels, 1985
 (continued)

NOTES:

- a Data taken from Table 1 of source. See also notes (b) and (c).
- b Based on an approximate 95 percent confidence level (i.e., there is a 95 percent probability that the actual volume falls between the lower and upper limits). See API report for qualifications.
- c Percentages calculated as: $100 * (\text{upper 95 percent limit} - \text{estimated volume}) / \text{estimated volume}$. Lower limits presented by API and here are cut off at 0 bbls.
- d Totals from Table 5, percentages from Table 6 of source.
- e Total U.S. includes AZ, IN, KY, MO, NV, NY, OH, PA, SD, TN, and VA. The values for these States alone or in total cannot be calculated since the values in the rows were calculated independently by API (i.e., the lower and upper limits and the estimated volumes for each State were calculated separately) and are not additive. Similarly, the U.S. totals for lower and upper limits was calculated independently by API and are not simply the total of the State limits.

SOURCE: American Petroleum Institute. 1988 (June). *API 1985 Production Waste Survey. Part II - Associated and Other Wastes Statistical Analysis and Survey Results*. Final Report.

Figure 2-1 shows the percentages of all associated wastes that were made up of completion and workover fluids. As can be seen, fluids were generated in by far the largest volumes of any associated waste. Overall, API estimated that these fluids constituted 49.3 percent of all associated wastes generated. Were on-site injection included, the percentage would be over 75 percent (see discussion of Table 2-6 below).

2.2.3 Rates of Completion/Workover Fluid Generation

As noted above, a number of analyses were undertaken to investigate whether API-estimated volumes and percentages of completion and workover fluids could be related to other data, particularly data for which post-1985 figures were available. If so, then the rate of fluid generation could be calculated and estimates

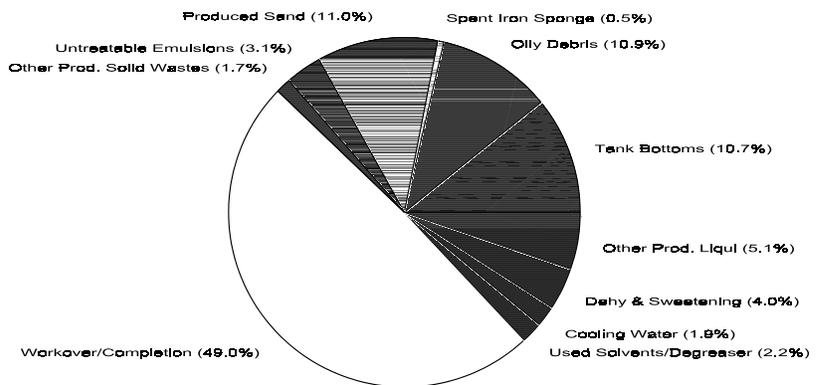


FIGURE 2-1. API Estimates of Completion and Workover Fluid Volumes as Proportions of All Associated Wastes, 1985

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could be made of the volumes of fluids generated in years since 1985. In summary, no such relationship was identified. (It should be noted that the relationships among variables were not tested statistically, so any conclusions presented are based on a simple examination of the data.) A number of tables were prepared that show the types of comparisons made; the results are briefly described below.

Table 2-4 presents, by State, onshore oil production (which was used by API to extrapolate waste volumes), and the volumes of all associated wastes and of completion and workover fluids. State volumes and percentages of oil production appear to show little or no relationship to fluid generation. Similarly, there seems to be no consistency between States in the proportion of all associated wastes that are comprised of completion/workover fluids.

Table 2-5 compares data on the number of producing wells to API estimates of completion and workover fluid generation. There is no apparent pattern in the volume of fluids generated per well. (Again, this conclusion is not statistically valid.) Bureau of the Census data on the total number of wells treated by hydraulic fracturing and by acidizing also were compared to API waste estimates. Specifically, Table 2-6 shows the API-estimated volume of completion/workover fluids generated per well treated by acidizing or hydraulic fracturing for selected states. Among those States, the volume per well ranges from less than two barrels per well treated in Alabama to 194 in North Dakota. The U.S. average was 41 barrels of fluids per well treated. As before, no pattern is apparent.

Unlike the other tables, Table 2-6 presents (for the U.S. but not for States), the volumes of fluids that are injected in on-site wells, which were excluded from the API associated waste survey results--the volumes were included under produced water in API's production survey because of inconsistencies in respondents' data.

(text continues on page 49)

<p align="center">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 2-4. Total Oil Production and Completion and Workover Fluids Generated per State, 1985</p>							
State	Total Onshore Oil Production		Associated Wastes Generated		Completion and Workover Wastes Generated		Percentage of State Completion and Workover Wastes to State Associated Wastes
	1000 Bbls ^A	Percent of U.S.	Barrels ^A	Percent of U.S.	Barrels ^A	Percent of U.S.	
Alabama	21,581	0.8	8,000	0.1	838	0.0	10.5
Alaska	651,599	23.1	55,000	0.5	5,526	0.1	10.0
Arkansas	19,044	0.7	19,000	0.2	6,281	0.1	33.3
California	353,550	12.5	2,379,000	20.2	124,375	2.2	5.2
Colorado	30,246	1.1	806,000	6.9	19,381	0.3	2.4
Florida	11,458	0.4	163,000	1.4	5,400	0.1	3.3
Illinois	30,265	1.1	205,000	1.7	3,831	0.1	1.8
Kansas	75,407	2.7	290,000	2.5	119,325	2.1	41.2
Louisiana	158,806	5.6	235,000	2.0	45,308	0.8	19.7
Michigan	27,300	1.0	161,000	1.4	302	0.0	0.2
Mississippi	30,641	1.1	50,000	0.4	22,494	0.4	45.1
Montana	29,768	1.1	337,000	2.9	327,115	5.8	97.0
Nebraska	6,943	0.2	9,000	0.1	1,606	0.0	16.0
New Mexico	78,530	2.8	355,000	3.0	327,788	5.8	92.3
North Dakota	50,857	1.8	330,000	2.8	318,419	5.6	96.5
Oklahoma	162,739	5.8	2,491,000	21.2	1,824,092	32.3	78.8

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-4. Total Oil Production and Completion and Workover Fluids
Generated per State, 1985
(continued)**

State	Total Onshore Oil Production		Associated Wastes Generated		Completion/Workover Wastes Generated		Percentage of State Completion/ Workover Wastes to State Associated Wastes
	1000 Bbls ^A	0.0	Barrels ^A	0.0	Barrels ^A	0.0	
Texas	867,122	30.8	3,080,000	26.2	1,931,041	34.1	64.1
Utah	40,792	1.4	47,000	0.4	5,845	0.1	12.9
West Virginia	3,555	0.1	422,000	3.6	411,241	7.3	97.5
Wyoming	128,514	4.6	150,000	1.3	76,137	1.3	51.6
Total U.S.	2,818,450	100.0	11,759,000	100.0	5,656,082	100.0	49.3

SOURCE: API 1988. Onshore oil production taken from this source because these figures were used for the statistical extrapolation to get State and U.S. totals.

Associated Waste Report:								
Completion and Workover Wastes (U.S. EPA, January 2000)								
TABLE 2-5. Completion and Workover Wastes Generated per Producing Oil Well and Amount of Oil Produced, 1985 (Excluding Fluids Injected in On-site Wells)								
State	Producing Wells		Onshore Oil Production		Completion and Workover Fluids			
	Number ^A	Percent of U.S.	Thousand Barrels ^B	Percent of U.S.	Barrels generated ^B	Percent of U.S.	Bbls per well	Bbls per 1000 bbls oil
Alabama	810	0.1	21,581	0.8	838	0.0	1.0	0.0
Alaska	977	0.2	651,599	23.1	5,526	0.1	5.7	0.0
Arkansas	9,700	1.5	19,044	0.7	6,281	0.1	0.6	0.3
California	49,874	7.8	353,550	12.5	124,375	2.2	2.5	0.4
Colorado	5,457	0.9	30,246	1.1	19,381	0.3	3.6	0.6
Florida	149	0.0	11,458	0.4	5,400	0.1	36.2	0.5
Illinois	31,100	4.8	30,265	1.1	3,831	0.1	0.1	0.1
Kansas	51,888	8.1	75,407	2.7	119,325	2.1	2.3	1.6
Louisiana	26,354	4.1	158,806	5.6	45,308	0.8	1.7	0.3
Michigan	5,143	0.8	27,300	1.0	302	0.0	0.1	0.0
Mississippi	3,468	0.5	30,641	1.1	22,494	0.4	6.5	0.7
Montana	4,196	0.7	29,768	1.1	327,115	5.8	78.0	11.0
Nebraska	2,091	0.3	6,943	0.2	1,606	0.0	0.8	0.2
New Mexico	18,697	2.9	78,530	2.8	327,788	5.8	17.5	4.2
North Dakota	3,697	0.6	50,857	1.8	318,419	5.6	86.1	6.3
Oklahoma	102,342	15.9	162,739	5.8	1,824,092	32.3	17.8	11.2

<p style="text-align: center;">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 2-5. Completion and Workover Wastes Generated per Producing Oil Well and Amount of Oil Produced, 1985 (Excluding Fluids Injected in On-site Wells) (continued)</p>								
State	Producing Wells		Onshore Oil Production		Completion and Workover Fluids			
	Number ^A	Percent of U.S.	Thousand Barrels ^B	Percent of U.S.	Barrels Generated ^B	Percent of U.S.	Bbbs per well	Bbbs per 1000 bbbs oil
Texas	209,040	32.5	867,122	30.8	1,931,041	34.1	9.2	2.2
Utah	1,944	0.3	40,792	1.4	5,845	0.1	3.0	0.1
West Virginia	15,895	2.5	3,555	0.1	411,241	7.3	25.9	115.7
Wyoming	12,038	1.9	128,514	4.6	76,137	1.3	6.3	0.6
Total U.S.	642,299	100.0	2,818,450	100.0	5,656,082	100.0	8.8	2.0

SOURCES:
 A API 1992. Oil production was not taken from this source as well since source B data were used for statistical estimation of waste volumes by State and for the U.S.
 B American Petroleum Institute 1988 (June).

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-6. Volume of Workover/Completion Fluid Generated per Well Treated by
Acidizing or Chemical Treatments or by Hydraulic Fracturing, 1985

State	Excluding on-site injection			Including on-site injection (D)	
	Workover/ completion Fluids Generated (bbls) (A)	Number of wells treated by acidizing or other chemicals or by hydraulic fracturing (B)	Fluids generated per well treated (bbls) (C)	Workover/ completion Fluids Generated (bbls)	Fluids generated per well treated (bbls)
Alabama	838	540	2	See note (D)	
California	124,385	8,600	14		
Colorado	19,381	3,660	5		
Kansas	119,325	5,540	22		
Louisiana	45,308	16,480	3		
New Mexico	327,788	5,780	57		
North Dakota	318,419	1,640	194		
Oklahoma	1,824,092	19,300	95		
Texas	1,931,041	47,080	41		
Utah	5,845	1,560	4		
Wyoming	76,137	4,820	16		
Total U.S.	5,656,082	139,140	41	17,722,000	127

NOTES:

A From source 1, which noted that workover/completion fluids injected in on-site wells were not included in the totals.

B Interpolated from 1982 and 1987 figures in source 2 for number of wells treated by Acidizing and Hydraulic Fracturing. See Appendix B for table providing 1982 and 1987 data and method of interpolation.

C As noted in note A, excludes fluids on-site underground injection.

D Based on estimate in API economic analysis (in ERT 1988) of total fluids generated, including those injected on-site. This was a National estimate and is not applied to States in the ERT economic analysis or here.

SOURCES:

1 API 1988

2 U.S. Department of Commerce 1990. See note (B).

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As indicated in the notes for Table 2-6, API has estimated (ERT 1988) that 80 percent of all completion/workover fluids that were not recycled or reused were injected in on-site wells. In a project that involved the potential costs of various regulatory scenarios, API estimated that all nonrecycled workover/completion fluids would be injected into Class I wells. In estimating the total volume of fluids, they attempted to account for fluids injected on-site, which were excluded from the 1985 survey. API's contractor, ERT, calculated that a total of 17,495,000 barrels would be injected, using the following equation:

$$TVI = (A * B) - C$$

where:

TVI = Total volume of workover/completion fluids injected.

A = 5,429,000 bbls not recycled/reused (see Table 3-1: 5,656,000 bbls total U.S. minus 227,000 bbls recycled/reused). Calculated by ERT.

B = 4. According to ERT, this multiplier was an API assumption to account for on-site injection. The rationale behind the multiplier was not provided.

C = 4,221,000 bbls. This volume was reported in the API survey as being sent to off-site commercial facilities (see Table 3-1). These were assumed by API and ERT to have been injected, so the total was reduced by this amount to avoid double counting.

Adding the total amount recycled/reused, 227,000 barrels, the total volume of workover/completion fluids generated in 1985 would come to 17,722,000 barrels, of which over 12,000,000 would have been injected on-site.

Thus, rather than 49.3 percent of all API-estimated associated wastes, as shown in Figure 2-1, completion/workover fluids actually amounted to 75 percent of a much larger volume when on-site injection is included in both totals: 17,722,000 barrels of fluids out of 23,541,253 barrels of all associated wastes.

Finally, a number of other variables were compared to API-estimated fluid volumes, among them drilling activity (number of oil and gas wells completed and footage drilled), gas production, percentage of stripper and nonstripper wells, stripper and nonstripper oil production, and other variables. No consistent relationship was found.

In all these analyses, there appears to be no consistent relationship between API-estimated volumes of completion/workover fluids and a number of other obvious variables. A number of reasons could account for this seeming lack of consistency:

- Actual variability in waste generation among completion and workover operations: this would be the result of variations among operators and operations across States.

- The exclusion of on-site injection volumes: this would severely affect the data for individual States, particularly given the apparent magnitude of those volumes. Unless on-site injection were consistent across States, this factor alone would disguise any apparent consistency in API's reported waste data. For a variety of reasons, including regulatory requirements, on-site injection is not likely to be consistent from State to State.
- Uncertainties in the API estimates: depending on their seriousness, such uncertainties could make any consistencies, even if they existed, meaningless. Among possible sources of error:
 - ▶ The use of oil production as the extrapolation factor: first, this does not account for completions and, although limited, workovers of gas wells. Second, the extreme inconsistencies among the States in the waste to oil ratio call into question the use of oil as the extrapolation factor at all (unless it is assumed that there is little or no within-State variation in the ratio). Third, the inconsistency in the waste-to-oil ratio across States calls into question the utility of estimating waste volumes for the total U.S.
 - ▶ The representativeness of respondents: the survey relies on the assumption that respondents' waste generation was representative of all operators in a State. This is not necessarily the case; the extreme variability of completions and workovers among and even within individual fields would weaken this assumption.
 - ▶ Accuracy and comprehensiveness of survey responses: the survey relies on full and accurate reporting. Among factors that could affect respondents' estimates are the variability of completions and workovers, which could tend to cause differences in operators' data; the fact that completions and workovers often (or usually) are performed by service companies may make at least some companies less aware of wastes generated, particularly if wastes are removed by the service company; and the fact that specific types of wastes and waste management are subject to different requirements in different States, thus affecting operators' awareness of specific wastes and the amount of waste data likely to have been available. Any or all of these could have led to respondents in different States having and reporting substantially different information on their waste generation (and management) rates.

The degree to which these factors may have affected API's estimates cannot be assessed, but all of these and other factors are likely to have operated. It should be noted that, given the survey constraints, the need (by API and EPA) to have State- and nation-wide estimates of waste generation, and the variability that clearly exists in the universe of completions and workovers, it is not clear that any limited survey could have been more accurate. Nevertheless, the volumetric estimates by API must be considered as being more suggestive than comprehensive. This should be kept in mind in the discussion below on the volumes of completion and workover fluids that API estimated were managed by specific methods.

2.2.4 Volumes of Fluids Used in Completion and Workover Operations

Another approach to estimating fluid volumes would be to relate the volumes of fluids used during completion and workovers and the volumes recovered. Large amounts of data, representing at least the extremes of recovery, would be necessary to account for the wide variability that exists. For example, fluid recovery could approach 100 percent (or even exceed 100 percent, since the recovered fluids could contain quantities of produced water or hydrocarbons) for some operations that do not involve the penetration of

formations by completion/workover fluids. It could be a much smaller percentage when fluids enter the formation: excluding fluids that enter flowlines of produced water or hydrocarbons, it could approach zero when large-scale fracturing jobs are involved. Little or no data were obtained that present both figures (i.e., fluids used and fluids recovered) for specific completion and workover operations. Maddin (1991), for example, in a study of surfactant toxicity and persistence in marine environments, analyzed well flow-back recovery in two wells. He concluded that 25 to 33 percent of cationic surfactants could be expected to be recovered, compared to 50 to 75 percent of nonionic surfactants (the cationic surfactant was theorized to more easily react with clay minerals as well as to be partitioned to the oil phase more easily than the nonionic chemical). In addition, return fluids from an inhibited hydrochloric acidizing treatment were analyzed; recovery of an amine-based acid inhibitor was estimated at 37 percent (Maddin 1991).

Even if a relationship could be determined, the volume of fluids used in completions and workovers, particularly during fracturing and acidizing, varies enormously depending on the specific operation being performed and the well on which it is being performed. Tables 2-7 and 2-8 present two examples of "suggested" fluid volumes to be used in various operations. Table 2-9 presents "typical" volumes discharged (presumably from offshore operations) and Table 2-10 presents actual discharges during a number of completion and workover operations in one area. As can be seen, the volumes used (or suggested for use) and the volumes discharged each vary by an order of magnitude or more. A number of the tables in Appendix A report the volumes of fluids that were used in several different types of well treatments. Again, the volumes vary by orders of magnitude. Unless fairly similar conditions are encountered (as occurs within individual fields), it is not possible to establish any sort of relationship between fluid use and fluid recovery and, thus, waste generation. (Within individual fields, volumes may be fairly standard, as may be the types and frequencies of well treatments. Because the prime variables affecting the relationship between fluid used and fluid recovered would likely be the treatment type and formation characteristics, it could be valuable to target specific fields or types of fields for future data collection.)

It should be noted that the volumes of workover fluids (including acidizing fluids) shown in Tables 2-7 through 2-10 are well specific and depend on the nature and extent of the problem or damage being treated (e.g., volume of formation damage that must be treated and carbonate content of the formation rock).

(text continues on page 54)

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 2-7. Volumes of Fluids Used for Selected Offshore Workover and Completion Operations	
Fluid	Volume
Completion fluid (clear, high-density)	Up to 80 m ³ per well
Mud acidifiers	Up to 150 m ³ per well
Packer fluids (clear)	"Few" m ³
Acidizing fluids	Not provided
Fracturing fluids	Not provided
SOURCE: Arctic Laboratories Limited, et al. 1983 (April).	

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 2-8. Suggested Volumes and Make-up of Acidizing Fluids		
Treatment	Volume ^a	Components
Sandstone acidizing ("standard three stage treatment")	50 gal/foot	<ul style="list-style-type: none"> • 15 % HCl • 1% corrosion inhibitor
	100 gal/foot	<ul style="list-style-type: none"> • 12 % HCl • 3 % HF • 1% corrosion inhibitor
	50 gal/foot	<ul style="list-style-type: none"> • 15 % HCl • 10% mutual solvent • 1% corrosion inhibitor
Carbonate acidizing ("Standard single stage treatment")	50 - 100 gal/ft	<ul style="list-style-type: none"> • 15 % HCl • 1% corrosion inhibitor
Paraffin/Asphaltene Control (single stage treatment)	50 gal/foot	Xylene or Toluene
NOTE: ^a Gallons of fluid per foot of formation to be treated		
SOURCE: Parker 1989. Source did not delineate between matrix acidizing and/or acid fracturing.		

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-9. Typical Volumes Discharged from Completion, Workover,
and Well Treatment Operations**

Operation	Type of Material	Volume Discharged (bbls)
Completion and Workover	Packer fluids	100 - 1,000
	Formation sand	1 - 50
	Metal cuttings	< 1
	Workover/completion fluids	100 - 1,000
	Filtration Solids	10 - 50
	Excess cement	< 10
Well Treatment	Neutralized spent acids	10 - 500
	Completion/Workover Fluids	10 - 200

NOTE: The distinction between workover and completion fluids and well treatment fluids follows the categories of discharges in EPA's Office of Water proposed effluent limitation guidelines for offshore operations.

SOURCE: Parker 1989

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-10. Volumes of Fluids Discharged During Workover, Completion, and Well
Treatment Operations in Cook Inlet, Alaska**

Type of Operation	Number of Operations ^a	Barrels discharged	
		Range	Average
Workover	8	100 - 1,200	647
Completion	12	25 - 1,295	282
Well Treatment	6	20 - 238.1	106
Acid jobs	4	10.8 - 25	132
Clean Out Tubing (using 15% HCl)	2	12 - 148	80

NOTE: Operations represent discrete batches of fluids used, each with characteristic additives, in completions, workovers, and well treatment operations. Multiple batches were used in some procedures: for example, three separate fluids for clay stabilization followed by an acid job followed by a mud acid job occurred in succession at one well; it appears above as three well treatments and two acid jobs.

SOURCE: EnviroSphere Company (1987)

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2.3 WASTE CHARACTERISTICS

Very little information on the characteristics of completion and workover fluids was found to be available: of over 100,000 acidizing and hydraulic fracturing jobs performed annually from 1977 through 1992 (see Tables 1-3 and 1-4 in section 1) and an unknown number since then, analytical data on a total of 14 completion and workover fluids were located¹ and are presented in Tables 2-11 through 2-13 (see also Section 2.3.1 below for information on EPA's 1992 sampling program). The data include:

- Six acidizing fluids, two of which were sampled after neutralization and three of which were sampled both before and after the acidizing job
- One hydraulic fracturing fluid, after the frac job
- Seven non-acid completion or workover fluids, one of which was described as a "weak acid" (EDTA) job, and two of which were sampled after treatment.

Tables 2-11 through 2-13 present the analytical data for the 14 fluids for which analytical data were available. The specific completion and workover operations sampled, most of which were from offshore wells, are described in the table notes. As can be seen, only one of the fluids was analyzed for organic constituents, and that one for only a few compounds. Of particular interest are the data in Table 2-12: acid fluids were sampled before and after workovers and then after treatment. Prior to the acid job, pH values were 1.4 to 1.6; recovered fluids had pH values between 7.2 and 7.6. Oil and grease and metals concentrations were uniformly lower in the post-treatment fluids (whether this was due to dilution could not be determined from the data). As has been true when discussing operations, wastes generated, waste volumes, and fluids/additives used, the analytical data show considerable variability.

Because a substantial number of additives used in completion and workover fluids are organic compounds, and because complex hydrocarbons from the formation are involved, organics would be expected in the fluids recovered following the operation. As noted above, however, only one of the 14 fluids was analyzed for specific (and very few) organic constituents (see Table 2-11). Several were analyzed for total organic carbon, as shown in Tables 2-12 and 2-13, with widely varying results. The temperatures and pressures to which fluids are subjected downhole could lead to changes in the types and concentrations of organic compounds, but no such data were obtained.

Acids used in completions and workovers may be partially or completely neutralized (spent) by contact with formation rocks. Very little data were obtained on neutralization, however. Dunlap and Houchin (1990) provided data showing that the first 1,000 barrels of returned fluids from a Gulf Coast area sandstone acidizing treatment showed a pH below 1, with the pH rising to about 4 after 1,200 barrels. In the Prudhoe

¹ It is likely that at least some States would have much more data, particularly underground injection control programs that require waste analyses. Similarly, some EPA Regions would have some data. The amount and availability of State and Region data were not determined, however, since the report relied only on readily available information. It was determined that the UIC program at EPA Headquarters does not have such data.

Bay area, the pH of one returned fluid declined from over 4 to below 2 during the first 200 barrels, then rose to 5 or higher after about 1,000 barrels. Thus, at least the first fluids that return to the surface after acidizing may still be acidic. This would depend on the carbonate concentration, and spending time. For some jobs, the acid may be left in the hole for a short time (minutes or a few hours). However for other jobs, the acid may be left in the hole for a matter of days. This may affect the degree the acid is spent.

As acids dissolve formation rock, metals in the formation matrix may be dissolved as well, and various additives used in acid and other fluids could be expected to return in their original form or as other compounds. Several of the additives used in stimulation, completion, and workover fluids are known to be toxic (Cottle et al. 1990, Leuterman et al. 1989). For many additives, however, the toxicity and/or the chemical composition is not known. According to Cottle, the agents of most consistent toxicity are biocides and dispersants. In addition, many viscosifiers, corrosion inhibitors, and scale inhibitors are groups of chemicals with known or suspected toxicity.

(text continues on page 59)

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-11. Composition of Four Fracturing and Acidizing Fluids

Parameter	Concentration (units)			
	Frac fluid ^{a,1} (mg/kg)	Neutralized spent acid ^{a,2} (mg/L)	Neutralized spent acid ^{a,3} (mg/L)	Acidizing Treatment Fluid ^{b,4} (mg/L)
pH (s.u.)	5.0	7.31	6.69	2.48
Oil and grease	NR	NR	NR	619.0
Aluminum	NR	NR	NR	0.0531
Antimony	42.96 - 46.7	9.4	1.0	< 3.9
Arsenic	< 0.002	< 0.01	< 0.05	< 1.9
Barium	7.24 - 7.25	12	9.5	12.6
Beryllium	0.06	< 0.01	< 0.05	< 0.1
Boron	NR	NR	NR	31.9
Cadmium	0.13	0.14	0.05	0.4
Calcium	NR	NR	NR	35.3
Chromium	0.06 - 0.07 (III)	0.11 (III) < 0.01 (VI)	< 0.1 (III) 0.2 (VI)	19.0 (total)
Cobalt	0.18	0.5	0.5	< 1.9
Copper	0.39 - 0.40	0.13	0.5	3.0
Fluoride	NR	1.3	40	
Iron	NR	NR	NR	572.0
Lead	0.214 - 2.40	0.9	0.4	< 9.82
Magnesium	NR	NR	NR	162.0
Manganese	NR	NR	NR	8.0
Mercury	0.0042 - 0.0048	< 0.01	< 0.05	< 0.1
Molybdenum	0.1	< 0.1	< 0.5	< 0.96
Nickel	0.23	0.5	0.8	52.9
Selenium	0.082 - 0.13	< 0.01	0.22	< 2.9
Silver	0.03	0.11	< 0.05	< 0.7
Sodium	NR	NR	NR	1,640.0

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-11. Composition of Four Fracturing and Acidizing Fluids
 (continued)

Parameter	Concentration (units)			
	Frac fluid ^{a,1} (mg/kg)	Neutralized spent acid ^{a,2} (mg/L)	Neutralized spent acid ^{a,3} (mg/L)	Acidizing Treatment Fluid ^{b,4} (mg/L)
Thallium	0.3	2.6	0.7	5.0
Tin	NR	NR	NR	6.66
Titanium	NR	NR	NR	0.68
Vanadium	0.1	0.4	< 0.05	36.1
Yttrium	NR	NR	NR	0.19
Zinc	2.06 - 2.14	0.37	4.7	28.5
Percent solids	10.91	NR	NR	NR
Aniline	NR	NR	NR	434
Naphthalene	NR	NR	NR	ND
o-Toluidine	NR	NR	NR	1,852
p-Cresol	NR	NR	NR	ND
2-methylnaphthalene	NR	NR	NR	ND
2,4,5-trimethylaniline	NR	NR	NR	ND
NOTES: NR Not reported ND Not detected 1 Composite sample of pad fluid and recirculated fluids from fracturing job done on well Shell California Production well 542-L-29. Samples taken June 30, 1982. Duplicate subsamples were analyzed, and both concentrations are presented where the analytical results differed. 2 Sample described as "neutralized waste spent acid," collected on 11/22/85, at Wayside Honor Rancho Well A-23 (in California, location otherwise unspecified). 3 Sample described as "spent acid from well stimulation after neutralized [sic] with lime." Sample taken on 4/18/85 following well stimulation, apparently from frac tank at Baker Tank Yard (Santa Paula, CA?). 4 This was described as a sample from one well being acidized for production enhancement at a coastal facility. Sampling details were not obtained (original source not obtained).				
SOURCES: a ERT 1988 b U.S. Environmental Protection Agency, Office of Water 1991 (March). Table VII-23: "Composition of Acidizing Treatment Fluid During Three-Facility Study." Original source (not obtained): ERCE, "The Results of the Sampling of Produced Water Treatment System and Miscellaneous Wastes at the THUMS Long Beach Company Agent for the Field Contractor Long Beach Unit - Island Grissom City of Long Beach - Operator," Draft, March 1990.				

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-12. Composition of Fluids From Three Acid Workovers,
Cook Inlet, Alaska

Parameter	Ranges of Concentrations (mg/L) ^a (number of samples taken)		
	Prior to workover (3)	After workover, prior to treatment (3)	After treatment, during discharge ^b (5)
Field pH (s.u.)	1.4 - 1.6	7.2 - 7.6	6.9 - 7.5
Oil and Grease	23 - 66	13 - 21	8.1 - 21
Cadmium	0.0063 - 0.21	<0.002 - <0.01	< 0.002 - < 0.01
Chromium	< 0.01 - 3.3	< 0.01 - 0.12	< 0.01
Copper	0.18 - 2.8	< 0.01	< 0.01
Lead	0.05 - 0.35	< 0.01	< 0.01
Mercury	0.00074 - 0.0019	< 0.0002	< 0.0002
Zinc	0.175 - 2.2	0.013 - 0.15	0.01 - 0.16
Field Dissolved Oxygen (ppm)	NR	0.1 - 0.4	0.1 - 0.3
Biological Oxygen Demand	NR	600 - 660	560 - 720
Chemical Oxygen Demand	NR	965 - 1,130	965 - 1,410
Total Organic Carbon	NR	249 - 350	294 - 321
Salinity (ppt)	NR	22.78 - 30.63	21 - 30.63
NOTES: NR Not reported ND Not detected. "Less than" signs (<) also denote nondetects, with the concentration presented the detection limit. a Samples of fluids from three acid workover jobs, one by Arco and two by Shell, were sampled as noted in column titles. b Two samples were taken for each of two of the three discharges.			
SOURCE: EnviroSphere Company, (1987). Data taken from Table 8.			

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)			
TABLE 2-13. Composition of Fluids From Seven Non-Acid Completions and Workovers, Cook Inlet, Alaska			
Parameter	Ranges of Concentrations (mg/L) ^a (number of samples)		
	Two completions, no treatment (2)	Three workovers, no treatment (3)	Two workovers, during discharge ^b (3)
Field pH (s.u.)	7.1 - 8.5	6.7 - 7.2	4.1 - 7.1
Oil and Grease	0.23 - 6.1	.34 - 21	1.9 - 74
Field Dissolved Oxygen (ppm)	4.7 - 6.2	0.4 - 2.8	0.1 - 0.5
Biological Oxygen Demand	6 - 108	3.4 - 400	460 - 865
Chemical Oxygen Demand	590 - 865	236 - 1,500	980 - 1,820
Total Organic Carbon	4 - 90	23 - 203	70 - 1,700
Salinity (ppt)	2.14 - 25.76	17.65 - 27.81	16.2 - 29.51
NOTES:			
a Two non-acid completions by Unocal, discharged off platform. Three non-acid workovers (two by Unocal, one by Marathon) discharged off platform. Two non-acid workovers (by Shell and Marathon) discharged after treatment; one of these workovers was actually a "weak acid" workover (EDTA).			
b Two samples of one of the treated non-acid workovers (not the "weak acid" one) were taken.			
SOURCE: EnviroSphere Company, (1987). Data taken from Table 8.			

Some have acknowledged that many chemicals used or produced in the oilfield are hazardous, or contain certain hazardous or toxic components (e.g., Buys 1991). Whole categories of oilfield chemicals contain hazardous substances: biocides, pH buffers, cement additives, corrosion inhibitors, defoamers, deflocculants, explosives, fuels, lost circulation materials, scale inhibitors, solvents, surfactants, and weighting agents. Many are hazardous chemicals within the definition of the Superfund Amendments and Reauthorization Act (SARA Title III) and operators must provide information on hazards, inventories, and management to State and local agencies (API 1989b).

In addition, Material Safety Data Sheets (MSDSs) are developed for all chemicals, including many (probably hundreds) used as additives, as part of OSHA's Hazard Communication Standards. An operator (or the service company performing the completion or workover operation) must review MSDSs for all chemicals used to determine which are hazardous or contain hazardous components. Table 1-2 listed several hundred (of the many thousands) additives that may be used in completion and workover fluids. It was beyond the scope of this report to undertake a systematic review of MSDS for the various chemicals

used in completions and workovers to determine their relative risk. It should be noted that most additives are used in fairly low concentrations, up to a few percent by weight of specific fluids; when recovered from wells in produced fluids, they would be even more highly diluted. In addition, as noted above, organic compounds may have undergone chemical changes in the temperature and pressure regimes encountered downhole.

2.3.1 EPA's 1992 Sampling Program

Because of the paucity of available analytical data, EPA undertook a sampling effort in 1992 to characterize a number of associated wastes, including workover and completion fluids. During this effort, EPA collected seven workover and completion samples for analysis from six oil and gas facilities located in New Mexico, Oklahoma, and Texas. Table 2-14 illustrates the type and location of the facilities where samples were taken, as well as brief descriptions of the samples. (Tables A-9A through A-9C show the treatments performed and the components of the fluids used at some of the facilities.) Tables 2-15 through 2-18, respectively, show the maximum and minimum concentrations of the parameters detected for metals, volatile organic compounds, semivolatile organic compounds, and general chemistry analytes. Appendix C presents analytical data for each sample. As aqueous samples, analytical results allow comparison to concentrations established under RCRA Subtitle C to identify wastes that exhibit the hazardous characteristic of toxicity. The wastes sampled are exempt from Subtitle C, so the characterization of wastes below is for illustration purposes only.

(text continues on page 67)

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)**

TABLE 2-14.

Workover/Completion Fluid Samples Collected During EPA 1992 Sampling Program

Facility	SCC Episode	Facility Type/Location	Sample number and Description
G	4410	Producing field (wells/ battery, mostly oil) Southwest Texas	23167: Sample collected from outlet side of separators after two weeks of pumpback following acid (HCl) fracturing job of well in Austin Chalk.
I	4410	Workover well (mostly oil) Southwest Texas	23174: Sample collected from wellhead after one hour of pumpback following acid (HCl) fracturing job of well in Austin Chalk. 23175: Sample collected from outlet side of separator after 12 hours of pumpback.
L	4456	Workover well (oil) West Texas	23628: Collected from wellhead from two swabbing runs of produced fluid, following HCl acid treatment
M	4457	Injection well drilling (for oil field EOR) Eastern New Mexico	23631: Spent fluid from completion of injection well (HCl treatment) collected from 500-bbl tank used to store recovered fluids prior to off-site removal.
O	4459	Centralized oil field production facility West Texas	23639: Collected during two swabbing runs from spigot in pipeline prior to storage tank and from rig floor. Irregular flow limited quantity available.
S	4464	Workover gas/condensate well Northwest Oklahoma	23652: Collected from wellhead during the initial swabbing run following acid (HCl) fracturing treatment using CO ₂ and gelled water three days before. Well had flowed back (to frac tank) for three days for sand cleanout but had not previously been swabbed for frac fluids.

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-15. EPA 1992 Sampling Program:
Workover and Completion - Detected General Chemistry Analytes

Analyte	Units	Detects Per Total Analyzed	Maximum	Minimum
Acidity	mg/L CaCO ₃	3/5	4,120	1,350
pH	std. units	6/6	6.63	3.61
Carbon, total organic	mg/L	4/5	546,400	94
Chloride	mg/L	5/5	157,000	14,426
Corrosivity	mmpy	2/5	1.75	0.09
Cyanide, Total	mg/L	1/7	0.052	0.052
Flashpoint, closed cup	deg. F	5/6	210	98
Fluoride	mg/L	3/5	2.25	0.65
Nitrogen, ammonia	mg/L	4/5	742	12.266
Nitrogen, Nitrate + Nitrite	mg/L	3/5	2.130	0.572
Oil & Grease, Total	mg/L	6/6	18,200	15
Oxygen Demand, Biochemical 5-day Tot.	mg/L	5/5	17,000	125
Oxygen Demand, Chemical	mg/L	5/5	38,275	475
Phenols	mg/L	5/6	1.53	0.097
Salinity	Salinity #	5/5	160.66	26.84
Solids, Total Dissolved	mg/L	5/5	368,880	19,380
Solids, Total Suspended	mg/L	5/5	14,000	65.5
Specific Conductance	umhos/cm	2/2	44,600	37,700
Sulfate	mg/L	5/5	1,692	212
Sulfide	mg/L	3/5	31.1	5.3

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-16. EPA 1992 Sampling Program: Workover and Completion - Detected Metals

Metal	Detects Per Total Analyzed	Maximum (µg/L)	Minimum (µg/L)
Aluminum	6/7	13,100	202
Antimony	2/7	148	100
Arsenic	4/7	693	15
Barium	7/7	3,360	66.5
Beryllium	4/7	25.1	4.7
Boron	6/7	45,200	4,840
Cadmium	7/7	82.3	7.6
Calcium	7/7	28,000,000	9,060
Chromium	6/7	1,320	48
Cobalt	2/7	46.5	40.9
Copper	6/7	6,070	6.8
Iron	7/7	1,140,000	7,190
Lead	2/7	6,880	907
Magnesium	7/7	13,500,000	875
Manganese	7/7	18,800	187
Mercury	1/7	6	6
Molybdenum	4/7	285	48.3
Nickel	5/7	510	38.9
Selenium	3/7	139	30.4
Silver	1/7	8	8
Sodium	7/7	45,200,000	33,900
Strontium	7/7	343,000	104
Sulfur	7/7	646,000	58,300
Thallium	1/7	67.3	67.3
Tin	3/7	291	135
Titanium	4/7	283	17.7
Vanadium	5/7	4,850	90.1
Yttrium	3/7	131	8.4
Zinc	6/7	3,610	7.3

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 2-17. EPA 1992 Sampling Program: Workover and Completion - Detected Volatile Organic Compounds					
Compound	AQUEOUS			SOLID	
	Detects Per Total Analyzed	Maximum (µg/L)	Minimum (µg/L)	Detects Per Total Analyzed	Single Sample Concentration (µg/Kg)
ACETONE	3/6	13,508	273	1/1	99,419
BENZENE	6/6	14,194	477	1/1	> 20,000
ETHYLBENZENE	6/6	3,597	154	1/1	> 20,000
METHYL CHLORIDE (CHLOROMETHANE)	1/6	57	57	1/1	ND
METHYL ETHYL KETONE (2-BUTANONE)	2/6	115	81	1/1	ND
METHYLENE CHLORIDE	1/6	24	24	1/1	ND
M-XYLENE	6/6	3,490	335	1/1	671,567
O- + P-XYLENE	6/6	2,670	161	1/1	671,567
TETRACHLOROETHYLENE	1/6	69	69	1/1	ND
TOLUENE	6/6	14,166	298	1/1	> 20,000
4-METHYL-2-PENTANONE	3/6	5,862	193	1/1	ND

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-18. EPA 1992 Sampling Program: Workover and Completion - Detected Semivolatile Organic Compounds

Compound	SOLID			AQUEOUS		
	Detects Per Total Analyzed	Maximum (µg/Kg)	Minimum (µg/Kg)	Detects Per Total Analyzed	Maximum (µg/L)	Minimum (µg/L)
BENZOIC ACID	2/4	8,707	7,995	0/3	*	*
BENZYL ALCOHOL	2/4	5,958	5,244	0/3	*	*
BIS(2-ETHYLHEXYL)PHTHALATE	1/4	381	381	0/3	*	*
DIBENZOFURAN	1/4	1,809	1,809	2/3	138	136
DIBENZOTHIOPHENE	1/4	5,666	5,666	1/3	222	222
FLUORENE	1/4	1,041	1,041	1/3	123	123
HEXANOIC ACID	1/4	1,289	1,289	0/3	*	*
NAPHTHALENE	4/4	33,050	4,379	1/3	1,050	1,050
N-DECANE (N-C10)	3/4	117,824	10,054	2/3	161,455	550
N-DOCOSANE (N-C22)	3/4	42,716	2,779	3/3	121,990	237
N-DODECANE (N-C12)	3/4	2,382,160	13,700	2/3	430,966	1,152
N-EICOSANE (N-C20)	2/4	7,402	2,951	2/3	125,332	451
N-HEXACOSANE (N-C26)	4/4	3,939,260	1,677	3/3	67,777	173
N-HEXADECANE (N-C16)	3/4	4,398,800	8,944	2/3	360,469	808
N-OCTACOSANE (N-C28)	4/4	255,672	1,844	2/3	30,457	422
N-OCTADECANE (N-C18)	4/4	3,183,400	3,573	3/3	337,028	281
N-TETRACOSANE (N-C24)	4/4	2,731,600	2,227	3/3	82,292	312
N-TETRADECANE (N-C14)	4/4	4,036,000	3,998	3/3	538,421	513

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE 2-18. EPA 1992 Sampling Program: Workover and Completion - Detected Semivolatile Organic Compounds
 (continued)

Compound	SOLID			AQUEOUS		
	Detects Per Total Analyzed	Maximum (µg/Kg)	Minimum (µg/Kg)	Detects Per Total Analyzed	Maximum (µg/L)	Minimum (µg/L)
N-TRIACONTANE (N-C30)	4/4	236,416	1,070	1/3	11,655	11,655
O-CRESOL	2/4	8,423	6,955	0/3	*	*
O-TOLUIDINE	0/4	*	*	0/3	*	*
P-CRESOL	2/4	1,505	1,307	0/3	*	*
P-CYMENE	1/4	11,337	11,337	1/3	144	144
PENTAMETHYLBENZENE	0/4	*	*	1/3	108	108
PHENANTHRENE	2/4	32,466	1,726	1/3	128	128
PHENOL	2/4	22,074	20,380	2/3	271	255
1-METHYLFLUORENE	2/4	107,318	1,985	1/3	163	163
1-METHYLPHENANTHRENE	1/4	66,832	66,832	0/3	*	*
2-ISOPROPYLNAPHTHALENE	1/4	21,164	21,164	0/3	*	*
2-METHYLNAPHTHALENE	4/4	179,690	2,172	1/3	1,634	1,634
2,4-DIMETHYLPHENOL	2/4	5,438	4,555	0/3	*	*
3,6-DIMETHYLPHENANTHRENE	1/4	152,296	152,296	0/3	*	*

As Table 2-14 illustrates, the types of samples included a spent completion fluid, spent workover fluids, and spent fracturing fluids.

There were several orders of magnitude differences between the maximum and minimum concentrations of the various analytes. As the tables show, relatively few metals or organics were found in all, or even most, of the samples. One sample (Sample No. 23639) exhibited the hazardous characteristic of toxicity based on its concentration of lead. Benzene was detected in all samples and ranged from 477 to 14,194 $\mu\text{g}/\text{L}$ in six samples (and $>20,000 \mu\text{g}/\text{Kg}$ in another sample reported by the laboratory in these units). Toluene showed similar variability. Six of the seven samples (all except No. 23628) exhibited the hazardous characteristic of toxicity for benzene². No other constituent was detected at concentrations that exceeded the toxicity characteristic threshold level.

The wide variation across samples is likely due to differences in processes and formation fluids at each respective facility. One sample (Sample No. 23174), fracturing fluid pumpback taken immediately after "bottoms up" from a southwest Texas oil production facility, dominated the maximum observed concentrations for semivolatile organics but not for volatile, metals, or general chemistry analytes. Concentrations reported for fluids (Sample No. 23175) taken from the same workover twelve hours later had decreased for most analytes by several orders of magnitude. The pH of the fluids sampled ranged from 3.61 for produced fluids collected during swabbing runs shortly after an acid treatment (Sample No. 23628) up to over 6.0 at several wells that had undergone acid treatments from 12 hours to several days before. In addition, one sample (Sample No. 23628), spent workover fluid taken from a northwest Texas facility, exhibited the hazardous characteristic of ignitability since its flashpoint was 98°F (see Appendix C, General Chemistry Table).

2.3.2 Other Associated Workover and Completion Wastes

Characteristics of drilling muds that are used as completion fluids (and few are now so used) are described in EPA's *Report to Congress* on oil and gas wastes (EPA 1987) and elsewhere (e.g., Leuterman et al. 1989; EPA 1985; Englehardt et al 1988). Similarly, water produced during completions and workovers are also described in the *Report to Congress* and elsewhere (albeit with some fluids/additives present as well).

² EPA used the Toxicity Characteristic Leaching Procedure (TCLP) to evaluate the toxicity of samples. As stated in the 1987 Report to Congress, "The TCLP was designed to model a reasonable worst-case mismanagement scenario, that of co-disposal of industrial waste with municipal refuse or other types of biodegradable organic waste in a sanitary landfill." Typically, oil and gas exploration and production (E&P) wastes are not disposed in municipal landfills. Additionally, sludge and oily samples can create operational and equipment difficulties leading to unreliable analytical results. This was a problem with a number of EPA's 1992 tank bottom TCLP samples. Therefore, "[t]his test may not reflect the true hazard of the waste when it is managed by other methods."

The characteristics of completion/workover wastes other than fluids were not examined in detail: as noted previously, these wastes also are generated by operations other than completions and workovers and the extent to which completions and workovers contribute to total waste volumes or affect waste characteristics could not be determined. In summary, these wastes and characteristics could include:

- Produced sand (and any recovered proppants) would surface suspended in fluids and could be coated with oil, solvents, emulsions, or other fluids.
- Paraffins would be dissolved or suspended in recovered fluids and would consist of heavy hydrocarbons. (Also of note: components of some fluids from treatments of wells that produce paraffinic crudes would be the aromatic solvents--xylene, toluene, etc.--that are often used to remove the paraffins, either before other well treatments or as specific workover operations.)
- Similarly, scale would be dissolved or suspended in recovered fluids or be present on downhole equipment that is brought to the surface during workovers. Scale may precipitate or settle in separators and/or treatment vessels or remain in solution in water or oil streams. Solid scales could be coated or saturated with various chemicals as well as hydrocarbons. Scale also may be radioactive, as discussed separately below.
- Cement slurry and cuttings would be Portland cement, additives included, and could contain some downhole material and fluids as well. Cuttings (e.g., from drilling through plugs) would be coated and/or partially saturated with drilling muds or other fluids.
- Used filters would contain whatever materials were filtered. Among other solids removed from completion/workover fluids, sand, scale, cement cuttings, paraffin, excess proppant, and clays could be expected, as could components of the fluids themselves (e.g., crude oil or diesel, invert emulsions, brines).
- Asphaltene sludges resulting from the reaction of acids with oil as well as oil-water emulsions may be produced with completion/workover fluids and would be characteristic of the fluid and formation hydrocarbons; they would obviously contain a variety of organic constituents, including benzene.
- Retrieved downhole equipment (e.g., tubulars, pumps, etc.).

Naturally Occurring Radioactive Materials (NORM)

Of concern in the case of some scale is naturally occurring radioactive materials (NORM). Scale may be "generated" as a waste during workovers, either with scale-specific treatments or incidentally during other treatments; during completion, scale would generally not yet have precipitated on downhole equipment and so would not be a waste of concern. As many as one-third of domestic oil and gas wells may produce some radium-contaminated scale. The geological location of the oil reserve and the type of production operation strongly influences the prevalence of NORM accumulations (EPA 1991b).

Depending on the formation, the mineral salts that constitute scale may be radioactive as a result of uranium or thorium and their decay products in the formation. Radium present in the formation is more soluble than

uranium or thorium and most likely to become mobilized by the liquid phases in the reservoir. As a Group IIa element, radium (as radon daughters Ra-226 and Ra-228 with half-lives of 1,600 years and 5.75 years, respectively, the decay product of most concern) behaves in a somewhat similar fashion to calcium, barium and strontium compounds and, like those compounds, can precipitate to form complex sulfates or carbonates, and deposit scale and sludge within the oil and gas production equipment. (A radium daughter, radon, may also be produced, particularly in gas streams (Grice 1991) although, with a half-life of 3.8 days, radon contaminated equipment does not likely pose a waste disposal problem (EPA 1991b)).

As produced from the well during and following workovers, scale could be dissolved or suspended in acid or other fluids and would be characterized by its basic structure (e.g., sulfates, silicates, and carbonates of barium, calcium, strontium). Scale may also be present on downhole tubing and equipment removed - and destined for disposal, reuse, reclamation, or repair - during downhole repair and maintenance operations. Scale dissolved or suspended in workover fluids (or, not relevant to this report, in produced water) may precipitate or settle in the bottom of tanks or treatment vessels, pits, and other storage or disposal units. As a result, sludges and bottoms may also contain NORM as a result of workovers.

Little or no information was obtained on the means by which NORM-containing scale in the various studies was brought to the surface (*i.e.*, in scale-specific or other treatment). One study suggested that it is possible to reduce the amount of NORM solids deposited on production equipment by reducing the scale formation. The driving forces for NORM scale precipitation in wells is the temperature and pressure changes resulting from production. 'Squeezing' and surface injection of scale inhibitor chemicals into producing reservoirs are recommended procedures for treating and controlling scale. The most effective scale inhibitor evaluated in the laboratory was the phosphinopoly-carboxylate (Oddo et al. 1993). However, this study did not address NORM carryover in the liquid stream or its final disposition.

API conducted a survey of NORM occurrence in oil and gas operations: in general, the Gulf Coast, northeast Texas, southeast Illinois, and southern Kansas were the areas that showed the highest equipment readings, although many areas showed levels of some concern (API 1989a). In a thirteen-State survey, up to 90 percent of production wells in Mississippi were reported to have NORM, compared to none or a few in Colorado, South Dakota, and Wyoming (McArthur 1988, cited in EPA 1991b). Ten percent of Mississippi wells were estimated to have scale with elevated radium concentrations (cited in EPA 1991b). An example was barium sulfate scale in production tubing in a Mississippi well; this was found in 1986 to contain 6,000 pCi/g of radium-226 and 1,000 pCi/g of thorium-232 co-precipitated in the scale matrix (EPA 1991b).

The higher radiation levels are typically found closer to the wellhead. Radium concentrations in separators were found to be a factor of ten less than those found at the wellhead. NORM scale deposits on wellhead equipment have concentrations ranging from one thousand to tens of thousands pCi/g, scale deposits in separators range from one to one thousand pCi/g, and the radium in sludges in tanks are generally around 50 pCi/g, a reduction of up to an order of magnitude. The highest concentrations of radium are typically found in hard scale deposits that form on the insides of pipes and valves (EPA 1991b).

Scales removed from various types of equipment in Aberdeen, Scotland, and Amelia, Louisiana, demonstrated the following radium activity levels (Reed et al. 1991):

- Scales from downhole assemblies ranged from 27 to 6,027 pCi/g, with a mean of 1,351
- Scales from downhole pumps ranged from 14 to 27,243 pCi/g, with a mean of 7,729
- Scale from tubing ranged from 27 to 9,729 pCi/g, with a mean of 1,459.

Sludges from U.S. oil production separators (the area of the U.S. was not described, but the context of the article would suggest Louisiana) showed radium activity levels ranging from 1,000 to 22,220 pCi/g, and sludges from gas separators showed polonium activity of 0.5 to 326 pCi/g (Reed et al. 1991).

In 1992, EPA's Office of Water obtained a sample described as produced sand from a workover of an oil well in coastal Louisiana. This sample was analyzed for radionuclides only. Results are shown in Table 2-19. This sample exceeded the Primary MCL for radium-226 (8.5 pCi/L) and radium-228 (13.0 pCi/L).

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 2-19. EPA 1992 Sampling Program: Detected Radionuclides	
Radionuclide	Sand from Well Workover (23598) pCi/L
LEAD-210	13.2
RADIUM-226	8.5
RADIUM-228	13.0

3.0 TYPICAL WASTE MANAGEMENT METHODS

3.1 OVERVIEW

As discussed in Chapter 2, the American Petroleum Institute associated waste survey (API 1988) is the only comprehensive examination of the means by which completion and workover fluids are managed in the United States. In the survey, respondents reported the volumes of fluids managed by the following methods:

- Recycling/reuse: recycled through crude oil reclaimers or returned to service companies. Fluids returned to service companies may or may not actually be reused or recycled, since the service companies may simply remove them for off-site disposal (e.g., injection).
- Roadspreading
- Landspreading
- Evaporation and other on-site pits
- On-site burial
- Surface discharge
- Off-site commercial facilities (including off-site injection)
- Other: "injection" was not a survey category and API indicated that on-site injection was often reported under "Other," but these volumes were excluded from survey results.

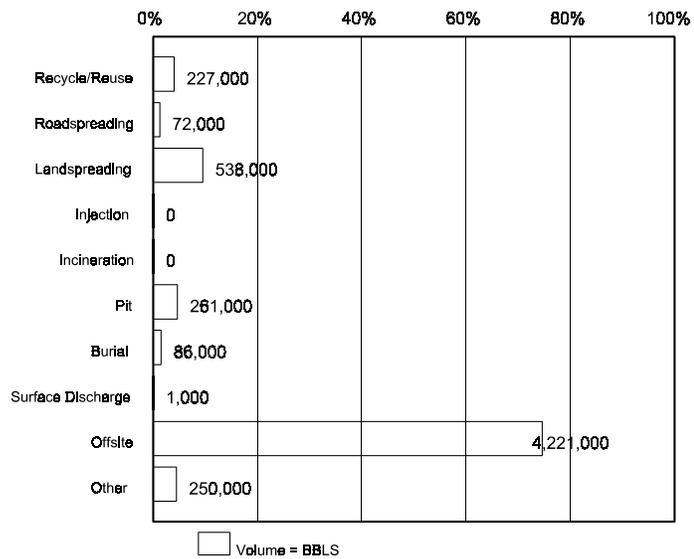


FIGURE 3-1. Percentages and Volumes of Completion and Workover Fluids Managed Using Various Methods
(SOURCE: API 1988)

The percentages and volumes of completion and workover fluids managed by each of these methods

are shown in Figure 3-1. As can be seen, the volume sent to off-site commercial facilities accounted for nearly 75 percent of the total. Although not explicitly stated by API, it is likely that the largest part of this volume is sent to off-site Class II underground injection control (UIC) wells--in an economic analysis performed for API, ERT (1988) assumed this, for example. As noted previously, using API data and assumptions in a report prepared for API (ERT 1988), the volume injected in on-site wells would be over

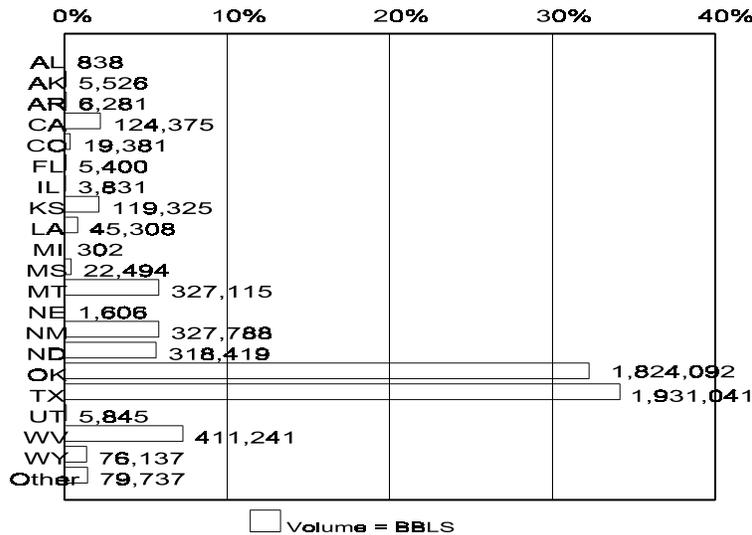


FIGURE 3-2. Percentages of Total U.S. Volumes of Completion and Workover Fluids Generated, by State, 1985 (SOURCE: API 1988)

12,000,000 barrels, over twice the volume of fluids managed in all other ways combined (ERT 1988). Keeping this in mind, and notwithstanding any other limitations on the API data (see Chapter 2), the results of the API survey remain instructive of the types of waste management methods used and at least the approximate proportions (if not volumes) that may be managed using specific methods. Accordingly, they are discussed in some detail in section 3.2 below.

Figure 3-2 shows the volumes of completion and workover fluids estimated by API to be generated and managed in individual States. As shown, Oklahoma and Texas dominate the percentages: API

estimated that over 60 percent of all completion and workover fluids were managed in these States alone (excluding, of course, those fluids injected on-site). The exclusion of volumes injected in on-site wells and other uncertainties described in Chapter 2 make the State volumes suspect at best. In general, the API data seem more useful for discussing waste management, not waste volumes.

The various management methods, and brief discussions of the potential environmental impacts arising from the use of such methods for completion and workover wastes, are discussed in section 3.2 below. Following this, since naturally occurring radioactive materials (NORM) are a special case, section 3.3 provides a brief overview of NORM waste management.

3.2 TYPICAL WASTE MANAGEMENT METHODS

Data from one table is discussed repeatedly in this section and bears some introduction. Table 3-1 shows the percentages of fluids within each State that were estimated by API to be managed by various methods. This table, for example, shows that 10.0 percent of all completion/workover fluids in California were recycled/reused, 2.6 percent of Texas fluids were recycled/reused, and so on. The States shown are those for which API provided waste management data. Also instructive would have been data that showed percentages, across all States, of fluids managed within each State by each method. However, because the API estimates were derived independently for each State and for the U.S. as a whole, they cannot be summed across methods (for example, API estimated that, for the U.S. as a whole, 86,000 barrels of completion/workover fluids were buried on-site; however, if on-site burial totals for the 10 States for which API derived independent estimates are added, the total comes to over 101,000 barrels, more than the National total).

The following subsections describe each of the waste management methods identified as being used for completion and workover fluids. Other nonfluid completion/workover wastes are also discussed briefly. Also included are brief discussions of the use of the methods in various States, as reported in Table 3-1.

3.2.1 Recycling and Reuse

API estimated that only about four percent of completion/workover fluids were recycled or reused in 1985. Initially, this would seem surprisingly low, but since fluids introduced to production lines were excluded (see notes in Tables 3-1 for the definition API used in the survey), it becomes less surprising. Relatively few completion and workover fluids would be sent to crude oil reclaimers, except possibly crude oils that are used as fluids and that become excessively contaminated; as a result, the category is likely to include mostly those fluids actually reused by operators and those returned to service companies. It is not known if this includes unused fluids that are removed by service companies when they finish well completions or workovers and leave the site. As noted above, at least some of the fluids returned to service companies are likely to be disposed of rather than reused. Specialty fluids, including weighted brines and oil-based muds/fluids, are more likely to be reused than are other fluids (API 1988a). Chapter 4 also discusses reuse and recycling.

Fluids in several States were recycled/reused more than one would expect based on the National average (four percent) and on the States' total fluid generation: these include California (10 percent of the State's total), Florida (83 percent of a low total), Kansas (12.2 percent), Louisiana (25.1 of a surprisingly low total, given the State's production), Michigan (100 percent of a very low total), and Wyoming (18 percent). In part because of uncertainties in the data, no clear reasons are evident. In contrast, API data for Oklahoma indicate a lower percentage than expected: only 0.7 percent of Oklahoma fluids were recycled/reused compared to the four percent National figure. Again, the reasons are not clear, but are likely related to the very high percentage of State fluids that are managed (primarily by injection) in off-site facilities.

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)**

TABLE 3-1. Waste Management Practices, By State, Used for Workover and Completion Fluids, 1985^a

State	U.S.		Volume Generated (bbl) and Percentage Disposed, by Method of Disposal ^c											
	Total Managed (bbl) ^b	%	AK		CA		FL		KS		LA		MI	
			bbls	%	bbls	%	bbls	%	bbls	%	bbls	%	bbls	%
Recycle/Re-use ^d	227,000	4.01	0	0.0	12,464	10.0	4,503	83.4	14,515	12.2	11,358	25.1	302	100.0
Roadspread	72,000	1.27	0	0.0	147	0.1	0	0.0	16,412	13.8	0	0.0	0	0.0
Landspread	538,000	9.51	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Pit ^e	261,000	4.61	5,526	100.0	1,556	1.3	897	16.6	12,530	10.5	5,553	12.3	0	0.0
On-site burial	86,000	1.52	0	0.0	2,532	2.0	0	0.0	42,178	35.3	0	0.0	0	0.0
Off-site ^f	4,221,000	74.63	0	0.0	106,501	85.6	0	0.0	33,690	28.2	27,635	61.0	0	0.0
Other	250,000	4.42	0	0.0	1,174	0.9	0	0.0	0	0.0	762	1.7	0	0.0
TOTALS	5,656,082	100.00	5,526	100.0	124,375	100.0	5,400	100.0	119,325	100.0	45,308	100.0	302	100.0

State	Volume Generated (bbl) and Percentage Disposed, by Method ^c							
	NM		OK		TX		WY	
	bbls	%	bbls	%	bbls	%	bbls	%
Recycle/Re-use ^d	204	0.1	13,253	0.7	50,357	2.6	13,685	18.0
Roadspread	0	0.0	0	0.0	53,330	2.8	228	0.3
Landspread	0	0.0	0	0.0	53,597	2.8	0	0.0
Pit ^e	2,584	0.8	56,014	3.1	138,447	7.2	26,504	34.8
On-site burial	851	0.3	26,449	1.5	28,382	1.5	1,232	1.6
Off-site ^f	324,148	98.9	1,583,902	86.8	1,548,731	80.2	34,487	45.3
Other	0	0.0	144,475	7.9	58,197 ^g	3.0	0	0.0
TOTALS	327,788	100.0	1,824,092	100.0	1,931,041	100.0	76,137	100.0

<p>Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE 3-1. Waste Management Practices, By State, Used for Workover and Completion Fluids, 1985 ^a (continued)</p>
<p>NOTES:</p> <p>a In conducting the survey, API used the following definition of workover/completion wastes: "Workover, swabbing, unloading and completion fluids include those fluids recovered from a wellbore that are not recombined with the production stream. They include spent acid or stimulation fluids and swab-tank fluids sent directly to disposal. They exclude fluids sent down flow lines, hauled to field batteries or NPDES permitted pits because these fluids are captured in other waste categories or under water disposal statistics."</p> <p>b Total U.S. includes AZ, IN, KY, MO, NV, NY, OH, PA, SD, TN, and VA. <u>Totals for these States cannot be calculated, individually or collectively, since the values for each reported State and for the total U.S. are independent statistical estimates made by API and are therefore not additive across States.</u> Total U.S. also includes totals for AL, AK, CO, IL, MS, MT, NE, ND, VT, and WV, for which API reported total volumes but not volumes managed by specific methods.</p> <p>c In addition to the disposition categories shown, API reported that 1,082 barrels were "surface discharged. None were reported as being incinerated or burned as fuel. On-lease injection in Class II UIC wells was reported in the total volumes of produced water in Part I of the API survey and were not reported separately as workover/completion wastes. Off-lease UIC injection was to be captured by the "off-site commercial category," although this was not explicitly stated by API. ERT (1988), as discussed in chapter 2, used API data and assumptions to estimate the total volumes of fluids generated; on-site injection would come to over 12,000,000 barrels. It should be noted that the percentages shown are the percentages managed using the specific management methods.</p> <p>d As defined by API: "storage for reuse" or "returned to service company."</p> <p>e As defined by API: "evaporation pits" or other "on-site pits"</p> <p>f Off-site commercial facility, presumably including off-site injection (see note c above).</p> <p>g API reports 67 of these barrels were incinerated.</p>
<p>SOURCE: American Petroleum Institute 1988. Data on quantities of workover/completion wastes taken from source. Percentages are calculated.</p>

3.2.2 Roadspreading

Roadspreading refers to the application of road mixes or paving materials formulated with asphaltic tank bottoms and oily debris, and to the application of certain oilfield liquid wastes such as in the case of road oiling. Roadspreading is often limited to lease roads and farm lanes which are typically unpaved. In such instances, and when conducted in accordance with State requirements, roadspreading can be considered a beneficial use of a material that would otherwise require disposal. Various oilfield wastes may be applied to roads (if permitted by State regulations) as dust suppressants, as surface deicers, or simply for disposal. Completion and workover fluids may be stored in tanks or pits (perhaps after passing through separators/treaters) prior to roadspreading or may be diverted directly to tank trucks for spreading. Nationally, API estimated that less than two percent of completion/workover fluids were roadspread in 1985. Two States accounted for most of the roadspread fluids: Kansas, where 13.8 percent of the State's fluids were roadspread; and Texas, where 2.8 percent were roadspread (it should be noted that this is 2.8 percent of the largest State fluid total). The API survey did not distinguish between roadspreading on private (i.e., on-lease) and public roads. API recommends a pH range from 6 to 9 for roadspread wastes.

Deuel (1990) recommended "threshold guidance values" for waste:soil mixtures for land disposal, including roadspreading, of exploration and production wastes: electroconductivity < 4 mmhos/cm, sodium adsorption ratio < 12, exchangeable sodium percentage for salinity < 15 percent, and oil and grease < 1 percent. Deuel was examining salinity and hydrocarbons, not metals or organic constituents that might be present in completion/workover fluids.

At the Cold Lake Production Project, Esso Resources Canada Ltd. requires that "oil sand waste" (predominantly bitumen, fine sand, and water [which can be workover wastes]) have a pH from 6.9 to 7.2, chloride less than 1,000 ppm, and phenols less than 0.005 ppm before they are used as road application materials. Run-off that can transport contaminants to roadside soils and vegetation is one of the major concerns. (Kennedy et al. 1990)

Wastes that completion and workover operations may generate other than fluids also may be roadspread. Among these are emulsions, sand, tank bottoms, and oily debris. As noted previously, the extent to which completions and workovers contribute to their generation is not known.

The primary environmental concern for roadspreading would be surface run-off, from storm water and snowmelt as well as from the application of excess volumes. Run-off that leaves the roadway could carry whatever constituents from roadspread materials that were on the road's surface. These could contaminate soils and sediments and could affect vegetation directly or could be accumulated in plants, then affect animals that use the plants as forage. In addition, volatilization of organics could present a localized problem, as could dust that carried metal or organic constituents. Because workover-generated scale may be present in tank bottoms or other wastes that are roadspread, NORM could also be a localized concern where very high radioactivity levels occur or where wastes were roadspread over a period of time.

However, no incidents were identified where roadspread completion/workover fluids or other completion/workover wastes were responsible for environmental damages.

3.2.3 Landspreading

The term "landspreading" encompasses a number of overlapping practices. These include land treatment (by volatilization or biodegradation of organics), land application (for evaporation, infiltration, or simple dilution), landfarming (for biodegradation and/or soil enrichment), and possibly landfilling. API recommends that free oil be removed from landspread wastes and that wastes be spread evenly and disked into the soil (API 1989). The extent to which operators who landspread completion/workover fluids follow these recommendations is not known, although many States regulate various forms of landspreading .

In 1985, API estimated that nearly 10 percent of completion/workover fluids were disposed/managed by landspreading (off-lease but noncommercial landspreading would presumably be included under landspreading, but commercial landspreading would be captured under off-site commercial facilities). Of States for which API provided data, Texas was the only State where completion/workover fluids were reported as being landspread, and 2.8 percent of Texas' fluids were landspread. Unless the data are in error, the States for which data were not provided (see Table 3-1, note (b)) accounted for fully 90 percent of landspread fluids. One possible explanation for the apparent discrepancy: landspreading is an ultimate treatment/disposal method and other methods may be used to store completion/workover fluids prior to their being landspread (e.g., tanks, pits). Some fluids that ultimately are landspread may have been reported under the method used for storage or solids disposal (e.g., pits, on-site burial). The structure of API's survey does not allow fuller explanation.

Deuel (1990) recommended identical "threshold guidance values" for waste:soil mixtures for landspreading of exploration and production wastes as noted above for roadspreading. API simply recommends that the wastes "not contain constituents at concentrations harmful to animals, soil or vegetation..." (API 1989).

For landspreading, API recommends that soil pH be maintained between 6 and 9, soil conductivity be less than 4 mmho/cm, and the oil and grease content be less than 1% in the final soil-waste mixture (API 1995a). API also developed general guidance values for 10 of 12 metals it considers to be of potential environmental concern (API 1995b). API's recommended guidance values for maximum soils concentration of metals are shown in Table 3-4 along with those from Louisiana State Wide Order 29-B and the Canadian Interim Soil Remediation Criteria for Agriculture as published by API (API 1995b).

As with roadspreading, nonfluid wastes that may be generated by completion/workover operations as well as other exploration and production activities may also be landspread, including sand, oily debris, and tank bottoms.

Environmental concerns from landspreading are similar to those of roadspreading and would involve all media: soils, ground and surface water, and air. Metals, organics, and particularly salts could contaminate

soils if fluids contain excess concentrations of any constituent or if excess fluids are applied. Excess salts can effectively sterilize soils for years, and some metals and organics can be incorporated into plant tissue and present risks to animals or humans who consume the plants. Precipitation-induced run-off or excess volumes of applied fluids can contaminate sediments and surface waters with salts, metals, and/or organic contaminants and constituents could leach into groundwater as well. Finally, volatilization of organics could present a localized problem, as could dust that carried metals or organic constituents. Because workover-generated scale may be present in tank bottoms or oily debris, NORM could also be a localized concern where very high radioactivity levels occur or where large volumes of wastes are landspread over a period of time. However, like with roadspreading, no incidents were identified where landspread completion/workover fluids were responsible for environmental damages.

US EPA ARCHIVE DOCUMENT

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
Table 3-2. API, Louisiana 29-B, and Canadian
Maximum Soil Concentration Values for Metals**

Element	API Guidance	Louisiana 29-B	Canadian Agriculture
Arsenic	41	10	20
Barium	180,000	20,000 40,000 100,000	750
Boron	2 mg/L	--	2 mg/L
Cadmium	26	10	3
Chromium	1500	500	750
Copper	750	--	150
Lead	300	500	375
Mercury	17	10	0.8
Molybdenum	--	--	5
Nickel	210	--	150
Selenium	--	10	2
Zinc	1400	500	600

All concentrations in mg/kg unless otherwise specified.

Source: API 1995b

3.2.4 On-site Pits

In general, workover/completion fluids are stored in two types of pits: reserve pits, which receive all or most drilling wastes and possibly completion fluids; and production pits, which may be constructed specifically for individual workover operations or may be used for a variety of other production wastes (e.g., settling or sediment pits, general purpose evaporation pits). Reserve pits may be used for temporary or long-term storage, or for permanent disposal of wastes. Production pits are generally not long-term. Most States require pit "closure" within specified periods after drilling or workover operations end (depending on the type of pit).

Nearly five percent of completion/workover fluids were managed in on-site pits in 1985. Reserve pits would have received mostly completion fluids while production pits would have received mostly workover fluids (as noted previously, similar operations are performed during completions and workovers and they use similar fluids, so the distinction between operation type may not be important). All of Alaska's completion/workover fluids were reportedly managed in pits, as were over 10 percent of Florida, Kansas, and Louisiana fluids, and almost 35 percent of Wyoming's. In addition, over seven percent of Texas fluids were managed in pits. In contrast, about one percent of New Mexico and California fluids were managed in pits, largely because most went to off-site facilities, as was also true of Oklahoma. Examinations of the numbers of producing wells and of well completions per State shed no light on the variability in pit management among States. The variability is likely related to regulatory requirements and the availability of alternative methods.

Reserve pits

Reserve pits are generally used to store drilling fluids, cuttings, and other wastes that accumulate at drilling sites. When a well is completed, completion fluids often join the other wastes in the reserve pit. In API's drilling wastes survey (as opposed to the associated waste survey), API obtained information on the types, but not volumes, of completion fluids that were disposed in reserve pits at 659 newly drilled wells, about one percent of all wells drilled in 1985.

Table 3-3 presents the percentages of wells in the survey at which completion fluids of various types were managed in reserve pits (as the table notes indicate, the percentages apply only to the surveyed wells, not to entire States or the U.S. as a whole). As can be seen, operators at 60 percent of the surveyed wells reported no completion fluids were managed in the reserve pit. Twenty-eight percent of reserve pit fluids were based on salt or formation water or were (presumably non-acid) water-based fracturing fluids. Of interest is that 35 percent of the reserve pits in the survey were lined, with significant differences among the States in the percentages of lined reserve pits. Notable for few lined pits were California (with one of 93 wells in the survey reporting a lined reserve pit), Illinois (none of 13), Kansas (none of 17), Louisiana (one of 29), Oklahoma (three of 43), West Virginia (two of 11), and Wyoming (eight of 44)--note that the table reports percentages of lined pits, whereas the parenthetical numbers above are the back-calculated number of lined pits. States with relatively high percentages of lined pits included Michigan,

Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000)											
TABLE 3-3. Types of Completion Fluids Discharged to Reserve Pits for Surveyed Wells, by State, 1985											
State	Number of onshore wells completed ^a	Number of wells in survey ^b	Lined pits ^{c, d} (%)	Type of Completion Fluid (percent, based on wells in survey) ^{b, c}							
				Acid	Air Foam	Fresh Water	Gel/ Polymer	Oil	Salt/ Formation/ Frac Water	Other	None _e
Alaska	242	6	33	0	0	0	0	0	33	0	67
California	3,208	93	1	2	0	6	16	0	45	1	29
Colorado	1,578	13	15	0	0	23	0	0	31	0	46
Florida	21	1	NR	0	0	0	0	0	0	0	100
Illinois	2,291	13	0	0	0	0	0	0	0	0	100
Kansas	5,560	17	0	0	0	6	0	6	24	0	65
Louisiana	4,908	29	4	0	0	0	0	0	21	0	79
Michigan	870	16	100	0	0	0	0	0	0	0	100
Mississippi	594	9	11	0	0	0	0	11	0	0	89
Montana	623	13	92	0	0	8	0	0	15	0	77
New Mexico	1,780	47	66	2	0	9	0	2	55	6	26
North Dakota	514	22	100	0	0	0	0	0	41	0	59
Ohio	3,818	13	100	0	0	0	0	0	15	0	85
Oklahoma	7,690	43	7	2	0	0	2	0	12	0	84
Pennsylvania	2,836	16	100	0	0	69	0	0	6	0	25

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)**
TABLE 3-3. Types of Completion Fluids Discharged to Reserve Pits for Surveyed Wells, by State, 1985
(continued)

State	Number of onshore wells completed ^a	Number of wells in survey ^b	Lined pits ^{c, d} (%)	Type of Completion Fluid (percent, based on wells in survey) ^{b, c}							
				Acid	Air Foam	Fresh Water	Gel/ Polymer	Oil	Salt/ Formation/ Frac Water	Other	None ^e
Texas	23,915	219	47	1	0	3	0	0	26	0	70
Utah	364	15	33	7	0	0	0	0	53	0	40
West Virginia	1,419	11	18	0	9	82	0	0	9	0	0
Wyoming	1,497	44	18	0	0	7	0	2	27	0	64
Other States ^f	6,006	19	27	0	5	0	0	0	16	0	79
TOTAL	33,201	308	35^d	1	0	7	2	1	28	1	60

NOTES:

NR Not reported.

a Estimated. Taken from table for survey question 9.B. Presented for comparison to sampled wells. It should be noted that this total includes both produced oil and gas wells and dry holes. According to the API *Basic Petroleum Data Book*, the total number of oil and gas wells completed for production in 1985 was about 49,500.

b From table for survey question 6.B.

c Percentages are reported only for surveyed wells and are based on the numbers of wells, not quantities of wastes; they are *not* extrapolations to State or U.S. totals and are *not* percentages of wastes managed in pits. Row totals may not add to 100 percent due to independent rounding.

d From table for survey question 11; apparently, includes any liner other than bentonite in drilling muds (see survey questionnaire). The number of wells for FL, LA, ND, TX, and CA were lower in the table for question 11 (resulting in a total of 649) than for question 6.B (a total of 659, as shown). Thus, the percentages of lined pits were based on a slightly lower number of pits than shown for these States.

e Presumably, this response indicated that no completion fluids were discharged to reserve pits and were managed by other means.

f Other States include AL, AR, IN, KY, NE, NV, NY, and OR. Percentages for this row were back-calculated from data presented by API.

SOURCE: American Petroleum Institute. 1987 (October). *API 1985 Production Waste Survey, Statistical Analysis and Survey Results -Part I Drilling Waste*. Final Report.

North Dakota, and Pennsylvania (where all pits were lined), Montana (12 of 13), and Texas (103 of 219). No pattern was discerned between the type of fluid managed and the likelihood of the pit being lined.

Reserve pits are typically excavated below-grade and may be surrounded by raised berms or dikes. Depending on environmental conditions and regulatory requirements, reserve pits may be lined with clay or synthetic liners (in the API data presented above, any liner other than bentonite in drilling muds would have qualified the pit as "lined"). In some areas, the excavation may be near or below the water table, in which case API (1989) recommends the use of liners. Liquids may be periodically removed from the pit, oil to go to reclaimers or the production line, water (brine, not fresh water) to be injected, roadspread, landspread, or otherwise managed. For example, this water is increasingly being used as make-up fluid for drilling muds.

The oldest and most common method of closing reserve pits is by dewatering and backfilling. The water is evaporated or otherwise removed (and managed as noted above) and the residue covered with material from the pit wall or soil and compacted. Remaining free liquids may be absorbed with dirt or straw before being covered with soil. Where dewatering is not practical, pit contents can be transported off-site or solidified in place; after removing as much water as possible, cement, fly ash, kiln dust, and polymers may be used to solidify pit contents. Solidification can immobilize, at least for a time, various constituents in the wastes. The solidified material then may be buried, left as it is, or used for landfill cover or road material (Jones and Leuterman 1990). If the surface of backfilled pits is not carefully graded and revegetated or otherwise protected, over time the cover could erode and may lead to uncontrolled releases.

Production pits

In many cases, various production pits may be used to store or dispose of workover fluids. These include pits constructed specifically for workover fluids as well as general-purpose evaporation pits. Construction and operation may be no different than for reserve pits, or they may be less or more sophisticated (the former is more common) in design. According to API (1988a), unlined production pits are used for fresh water-based fluids and for inert materials such as low-hydrocarbon sand and filter media; lined pits are used for salt water- or oil-based fluids and other high-hydrocarbon material. Generally, production pits are closed by removing free liquids, then backfilling the pit or by removing the solids for on- or off-site disposal. Workover-specific pits may have to be closed within a specified period after workover operations are completed.

Other, nonfluid, workover wastes may be managed in various production pits. These include sand, sludges and emulsions, oily debris, and tank bottoms. As before, the extent to which workovers contribute to the total volumes of these wastes is not known.

Potential environmental impacts

As noted in the 1987 *Report to Congress*, relatively few environmental damage cases can be attributed to specific associated wastes, including completion/workover fluids. It may be noteworthy that, although over

100,000 wells have been acidized or hydraulically fractured per year over the past decade (see Table 1-4), with fluids containing a wide variety of toxic components, there was only one damage case documented in the Report for that time period that involved fracturing fluids³. It should also be noted that many of the damage cases presented in the *Report to Congress* resulted from releases from unlined reserve pits, many of which may have contained completion/stimulation fluids as well as drilling and other wastes.

The potential impacts associated with reserve pits are well-described in the 1987 *Report to Congress*. Of most concern while the pit is open are releases to ground or surface water, although soils may be contaminated and there may be releases to air as well. Chloride concentrations in reserve pits may range from 570 to 135,000 mg/l, oil and grease from 800 to 28,000 mg/l, and barium from 30 to over 56,000 mg/l. A wide variety of metals (including cadmium, chromium, and lead) and organic constituents (including benzene, toluene, and other volatile and semivolatile organics) may also be present. No information was obtained on the extent to which completion/workover fluids contribute to the mix of constituents in reserve pits. At and after closure, the potential for leachate to contaminate groundwater would still exist, as has occurred at some sites, as described in the *Report to Congress* (EPA 1987).

Because the range of wastes managed in workover pits is not as broad as reserve pits, they may be less variable. As noted in Chapters 1 and 2, however, the fluids (as used or as recovered) may contain significant proportions of various additives as well as hydrocarbons and formation material. Potential impacts would be similar to those associated with reserve pits, except that the relatively brief lifespans of most pits would reduce the possible damages during operations. In addition, workover pits would typically contain fewer solids, so residual impacts (e.g., to groundwater) could be less likely as well.

As with other management methods, pit solids that are generated by workovers and completions (e.g., scales and sludges, sand, oily debris, emulsions, tank bottoms, filter media) could be of concern as sources of metal and organic constituents, oily wastes, and NORM.

3.2.5 On-site Burial

According to API less than two percent of completion and workover fluids (a total of 86,000 barrels) were managed by on-site burial in 1985. It is not clear if this pertains to burial apart from backfilling or otherwise burying pit contents. It also is not clear if it actually pertains to the fluids rather than the solids

³ For the 1987 Report to Congress, EPA documented 61 damage cases that were considered to have met the documentation standards of RCRA Section 8002(m) (c). Generally, these cases were the result of practices that were in violation of State regulations at the time of occurrence or that would be in violation of current State regulations. Of the 61 damage cases, only two were reported to involve completion and workover fluids - specifically, fracturing fluids. In one case, damages to livestock, soil, and a domestic water supply were found to have occurred after produced water, oil, drip gas, detergents, fracturing fluids, and waste production chemicals were disposed in a ditch. In the other case, a domestic water supply was found to be contaminated with natural gas and fracturing fluid that resulted from a malfunction of the fracturing process used on an adjacent gas well. The malfunction allowed natural gas and fracturing fluid to migrate into and contaminate the domestic water source.

(as noted previously, API's survey specifically excluded all wastes except fluids from the completion/workover category), since burial of fluids does not seem likely. It is possible that respondents' mixed their responses for on-site pits and on-site burial (e.g., two operators, each of whom managed workover fluids in evaporation pits, then buried residual solids on-site, may have responded differently to the survey). It also is possible that operators who landfarmed their fluids by incorporating them into the soil reported on-site burial, since landfarming was not called out as a discrete management method. At any rate, there is no clear indication of exactly what was encompassed by "on-site burial" in the survey. Among the States, only Kansas stands out: over 35 percent of completion/workover fluids were reported to be buried on-site.

Other wastes generated by completions and workovers also are buried on-site, notably sand, tank bottoms, and oily debris. Indeed, produced sand accounted for over two-thirds of all buried associated wastes. As before, the proportions of these wastes' volumes generated by completions and workovers are not known.

As noted previously for roadspreading and landspreading, Deuel (1990) recommended identical "threshold guidance values" for waste:soil mixtures for on-site burial of exploration and production wastes. As discussed earlier, Deuel was examining salinity and hydrocarbons, not metals or organic constituents that might be present in drilling fluids as well as completion/workover fluids.

McFarland et al. (1990) report that selectively burying wastes (i.e., not mixing with soil) at depths over 90 cm below the surface may be necessary to avoid upward salt migration that would interfere with natural or artificial revegetation. Their concern was on salts rather than any toxic constituents.

On-site burial should pose direct risks neither to surface waters (so long as the material remains buried and salts or other contaminants do not migrate to the surface) nor to air. Depending on the site, the material buried, and the constituents involved, leachate contamination of groundwater could be of concern. Indirectly, surface water could be affected in such cases if there is groundwater recharge of surface waters. If free liquids are actually buried, clearly the risk of leaching would be increased. Since the nonfluid wastes would be the same as discussed previously, so too would the constituents of concern in those wastes: metals, organic constituents such as benzene, salts, and NORM. Clearly, if the surface is not carefully graded and revegetated or otherwise protected, materials overlying buried wastes could erode and may lead to uncontrolled releases, so this can be critical (though generally unremarked in API guidance). However, no incidents were identified where completion/workover wastes buried on-site were responsible for environmental damages.

3.2.6 Other (unspecified) Management Methods

Nationally, API estimated that in 1985 over four percent of completion and workover fluids were managed by means other than those described above and below. API (1988) stated that "in many cases," operators had specified the disposal techniques for the waste volumes they reported under the "other" category. Other respondents had not specified a technique: when they had not and where there were "suspiciously

large volumes," API clarified and confirmed the response with the operator. (For respondents who identified injection as the "other" method, API eliminated the volumes from the results since the fluids were assumed to have been commingled with produced water before injection and thus had been accounted for in the production waste survey.) For smaller unspecified volumes reported under "other," API apparently did not determine the actual method used. Thus, some of the volumes reported to have been disposed by "other" methods are likely to have been injected, although other methods could also be included. It is not clear what these might be, but uncertainties in the survey questionnaire could have led to a variety of responses. For example, the survey did not include any provision for off-site but noncommercial management methods. In some oil and gas fields, centralized noncommercial facilities may be used to manage many exploration and production wastes. Similarly, disposal in landfills was not identified as a management method on the survey. Finally, minor or localized management methods would naturally fall in this category, such as disposal to publicly owned treatment works (as is known to occur in water reclamation lines that are treated by the Los Angeles County Sanitation District, but may not have been accounted for in the API survey) or incineration (which occurred with 67 barrels of Texas fluids in the API survey).

States where completion/workover fluids were reportedly managed using "other" methods in 1985 included California (about one percent of the State's total fluid volume), Oklahoma (almost eight percent), and Texas (three percent).

The environmental impacts of unspecified management methods clearly cannot be described. As for discharge to POTWs, the major impact could include treatment plant upset (in which components of the influent--such as salts, metals, organics, or oil and grease--could kill the bacteria that serve to treat sanitary sewage or reduce their effectiveness), pass through (which occurs when pollutants simply pass through treatment plants), and contamination of sewage sludge. Incineration, on the other hand, would generally destroy organic pollutants.

3.2.7 Off-site Commercial Facilities

Nationally, nearly 75 percent of completion and workover fluids were reported by API to have been managed in off-site commercial facilities. Specific management methods used for wastes at such facilities can include all of the methods described above as well as underground injection, which is described in section 3.2.9 below (as noted on several occasions previously, ERT in an economic analysis performed for API assumed that essentially all of the completion/workover fluids in this category were injected).

Notable among the States were California (where over 85 percent of completion/workover fluids were reportedly managed in off-site commercial facilities), New Mexico (nearly 99 percent), and Oklahoma and Texas (each over 80 percent). Also notable were Kansas (28 percent managed off-site), Louisiana (61 percent), and Wyoming (45 percent). In addition to the volumes reported by API, some wastes reported as returned to service companies (and thus included under reuse/recycling) would likely be transported by the service companies for off-site management.

Whether injected or managed by other methods, the potential environmental impacts from off-site commercial management of completion/workover fluids should be similar to those managed on-site or noncommercially. One possible difference between off-site commercial management of wastes and on-site management would be the wider variety of wastes likely to be managed in various units at commercial facilities. The wider variety of wastes could include a wider variety of constituents of concern, possibly in more concentrated forms.

API (1989) counsels caution in using off-site facilities due to the joint and several liability provisions of CERCLA and similar State statutes. API recommends periodic inspections of commercial facilities by States and/or operators to verify compliance and identify areas of environmental concern. Finally, API suggests that operators track off-site waste shipments, even where this is not required.

3.2.8 Underground Injection

All indications are that the vast majority of completion and workover fluids are injected into the subsurface along with produced water. As illustrated in Figure 3-1 and shown in Table 3-1, API reported that nearly 75 percent of completion and workover fluids were managed in off-site commercial facilities, and most of this volume was likely injected in commercial wells (ERT 1988, API 1988a). As is noted repeatedly throughout this report, fluids injected into on-site (i.e., noncommercial) wells were not accounted for in API's associated waste survey results (API 1988). However, as discussed previously, on-site injection was estimated to have accounted for 12,000,000 barrels, more than twice the volume managed by all other methods combined, including off-site injection. If all fluids reported to be sent to off-site commercial facilities are assumed to be injected, then the percentage of completion/workover fluids injected would be almost 92 percent. This is based on the calculation:

$$100 * VI / TV = 91.9 \text{ percent}$$

where:

$$VI = \text{Volume injected} = 16,221,000 \text{ bbls} = 12,000,000 \text{ on-site} + 4,221,000 \text{ off-site}$$

$$TV = \text{Total volume} = 17,656,082 \text{ bbls} = 12,000,000 \text{ on-site injected} + 5,656,082 \text{ other (see Table 3-1)}$$

Most wells used for injection of oil and gas wastes are classified as Class II wells under the Underground Injection Control (UIC) program. Some States, however, may require certain wastes to be injected in Class I wells (e.g., California, when wastes are classified as hazardous wastes under State regulations (IOGCC May 1993)). Some States allow one-time annular injection (i.e., down the surface casing-production casing annulus) of reserve pit contents, so some completion fluids may be so injected. Otherwise, injection of completion/workover fluids would occur with much larger volumes of produced water (a few States allow annular injection in Class II UIC wells). API (1989) has recommended that injection be used for disposal of all exempt exploration and production wastes where practical.

Injection wells are acidized and fractured using fluids similar to those used for production wells. Thus, the composition of completion/workover fluids would usually not disqualify them from injection; this may not be true for fluids with high solids contents (which may require filtering or other solids removal) or fluids with high levels of fluid loss or lost circulation additives (the injection of such additives would be counterproductive in injection wells since the intent is for the receiving formation to accept large volumes of fluid). Other properties of acidizing and chemical treatment fluids may provide a net benefit to injection wells to the extent that the fluids retain their ability to increase formation porosity and/or permeability.

The potential environmental impacts from underground injection would be largely confined to groundwater, except insofar as surface management (in tanks or pits) prior to injection presented risks to soils, surface water, or air. Leaks from improper injection well casing or corroded casing can allow fluids to escape the injection well before reaching the receiving formation and possibly to contaminate fresh water aquifers. In addition, the presence of abandoned wells in the same formation in which injection occurs may provide a conduit for injected fluids to reach overlying aquifers or even the surface.

In the 1987 *Report to Congress*, EPA cited instances where underground injection had contaminated underground sources of drinking water and/or other groundwater. Similarly, the U.S. General Accounting Office (1989) cited a number of such cases. In none of these cases were completion or workover fluids implicated in the damages, however.

3.3 NORM WASTE MANAGEMENT

According to API, the three categories of NORM waste which must be disposed of include: loose NORM (scale, sludge, and contaminated soil), NORM-contaminated tubulars, and NORM-contaminated equipment other than tubulars (*e.g.*, separators, tanks, valves, etc.). EPA has estimated that 25,000 metric tons of NORM contaminated scale and 225,000 metric tons of NORM contaminated sludge are generated in the petroleum industry each year (Smith, et al 1995, EPA 1993). NORM waste disposal methods were studied by API to determine their appropriateness for NORM waste (API 1992). These suggested methods, all of which API reported are subject to approval by appropriate regulatory agencies, are described below:

Plugged and abandoned wells: NORM could be placed in wells during plugging and abandonment operations using the following procedures:

- *NORM Scale, Sludge and Soil.* NORM obtained from cleaning tubulars and production equipment could be mixed with cement slurries, if there are no hydrocarbons present. The slurry mixture can then be squeezed into the formation or spotted as wellbore plugs located below the plug used to isolate the lowermost underground source of drinking water (USDW).

Alternatively, NORM wastes could be blended with the well control fluids and circulated in the wellbore below the lowermost USDW. NORM fluids should be isolated in the wellbore between cement plugs.

NORM wastes could be "containerized" in tubulars and disposed of by placing the material inside joints of tubing and placing the tubing in the wellbore as discussed below.

- *NORM-Contaminated Tubulars.* NORM-contaminated tubulars could be installed beneath or between all plugs in the wellbore, or cemented in place within a full cement column. A plug should then be set in the casing below the lowermost USDW and above the top joint of tubing.

Well Injection and Hydraulic Fracturing. Sludge and scale wastes containing NORM could be injected or fractured into formations which are isolated geologically and mechanically from USDWs. These NORM wastes could be mixed using mud or cement mixing equipment. Injection of the NORM waste would be followed by a non-contaminated fluid such as water or mud so that all the NORM wastes are completely displaced into the formation.

Disposal at a Licensed NORM Waste Disposal Site. Norm wastes could be disposed in an offsite commercial NORM disposal facility. As of April, 1992, only one such facility was known to exist according to API.

Equipment Release to a Smelter. When NORM-contaminated material is smelted, residual NORM mainly accumulates in the slag. API reports this method is currently undergoing study to ascertain its viability.

Landspreading and Burial. Loose NORM could potentially be disposed of by landspreading and both loose NORM and NORM-contaminated equipment could potentially be disposed of by burial. API indicates that regulatory agencies have not yet approved of disposal by these methods. Based on a study sponsored by the U.S. Department of Energy (DOE), the Argonne National Laboratory determined that for landspreading of NORM contaminated scales and sludges, the exposure pathway of greatest concern is external irradiation. Argonne recommends that restrictions on landspreading these wastes should be implemented in all States to limit potential radiological doses to the general public (Smith, et al 1995).

Miller et al. (1991) noted that there are three options for disposing of NORM waste, NORM-containing scrap, and NORM site cleanup:

- Consolidate and store the material on company-owned property
- Dispose in a licensed radioactive waste facility
- Dispose as authorized by appropriate regulatory agency(ies).

Because of the concerns for proper disposal, NORM is usually managed and stored onsite (API 1992). Offshore discharge is regulated under an EPA Region VI General NPDES permit made final in mid-1993, which prohibits the ocean discharge of NORM-contaminated solids. The Mineral Management Service (MMS) allows disposal of NORM by injection and encapsulation in abandoned wells. Transportation of NORM for onshore disposal is also allowed. DOT regulations govern the transportation of NORM on the

outer continental shelf, and include requirements for shipping papers, markings, labeling, packaging, placarding and emergency response (Shannon 1993). Alaska's Department of Environmental Conservation, in concurrence with EPA and the Alaska Oil & Gas Conservation Commission, authorized the injection of NORM materials as Class II solids, or the mixing of the scale in cement slurries for use in well abandonment (Lowe 1993). Louisiana has promulgated NORM regulations to date, including a moratorium on downhole disposal. Texas has also developed NORM regulations. Other States are either conducting their own surveys for NORM occurrence or are participating in the API studies (EPA 1991, IOGCC State Reviews).

Louisiana radiation regulations require that certain areas be designated as restricted if radiation concentrations or exposures exceed certain limits. Unrestricted disposal of NORM waste and NORM-contaminated material is allowed if the radiation dose (at accessible points or areas) does not exceed 50 microRoentgens per hour. Decontamination or disposal of more radioactive materials must be under appropriate licensing. Land may not be transferred for unrestricted use (e.g., at lease end) if radium-226 activity exceeds background by more than 5 pCi/g averaged over the top 15 cm of soil or 15 pCi/g averaged over 15-cm layers below the top 15 centimeters. Requirements in Texas, on the other hand, exempts NORM waste/material at levels of contamination by radium of 5 pCi per gram, rather than the Louisiana "dose" rate.

In a pathway exposure analysis, Chevron examined disposal in a plugged abandoned well, landspreading, and various burial scenarios. Their analysis found all but shallow burial in arid environments acceptable. They noted that disposal in plugged and abandoned wells was an option "below regulatory concern" and was "most desirable." Landspreading was described as viable for site remediation. Closure of production pits "by usual means" (dewatering and burying) was also found acceptable in humid environments. (Miller et al. 1991, Miller and Bruce 1990)

4.0 WASTE MINIMIZATION AND POLLUTION PREVENTION

The title of the 1976 amendments to the Solid Waste Disposal Act, the "Resource Conservation and Recovery Act," focussed attention on what was and is the ultimate purpose of RCRA: the prevention of pollution by conserving and recovering resources. The various programs administered by EPA under the Clean Air Act; the Federal Water Pollution Control Act; the Toxic Substances Control Act; the Federal Insecticide, Fungicide, and Rodenticide Act; the Safe Drinking Water Act; and other statutes all have that goal, and have made substantial progress toward its achievement by requiring specific pollution control technologies, placing limits on releases to the environment, and/or monitoring and reporting on toxic materials used or released. In response, those who are subject to the programs meet these requirements by changing industrial processes or feedstocks, by reducing or eliminating the volume or releases, and/or by installing treatment technologies. In the 1984 amendments to RCRA, Congress declared it to be National policy that the generation of hazardous waste was to be reduced or eliminated. Finally, in the Pollution Prevention Act of 1990, Congress formally established a National policy of "pollution prevention."

Having long complemented its traditional permit programs, which require treatment or otherwise limit releases, with active encouragement of what has become to be known as "pollution prevention," EPA in May of 1992 responded to the 1990 Act with a formal "Statement of Definition" that placed "pollution prevention" first in a hierarchy of approaches to be used by EPA in its environmental management activities (EPA 1992). In decreasing order of preference, the hierarchy includes:

- *Pollution prevention*: source reduction and other practices that reduce or eliminate the creation of pollutants through increased efficiency and/or conservation of resources. It includes reducing the amount of hazardous substances, pollutants, or contaminants entering any waste stream or being released prior to recycling, treatment, or disposal; or reduces risks associated with releases.

Source reduction specifically includes modifications to equipment, technology, processes, and procedures; changes in products; substitution of raw materials; and improvements in housekeeping, maintenance, training, or inventory control.

- *Recycling*: specifically, out-of-process recycling, since in-process recycling is included in pollution prevention above. This would include environmentally sound beneficial reuse of "waste" materials as well as energy recovery.
- *Treatment* prior to disposal or release: this would not include contained disposal
- *Disposal or release*.

Because the purpose of well stimulation is to enhance oil or gas recovery, which can enable existing resources to be recovered, it could be argued that such practices are a form of source reduction: they often reduce produced water flows and usually improve water-to-oil ratios, thus reducing the amount of waste; in addition, continued or increased production from existing wells may reduce the need for additional wells (assuming that the "shortfall" is not made up by energy conservation or imports).

The volume of completion/workover fluids estimated by API to be recycled or reused was discussed briefly in the previous section. In addition to fluids, other completion/workover wastes may often be recycled and reused. These include excess proppant as well as produced sand and scale.

In discussing North Sea operators, a representative of the Norwegian State Pollution Control Authority stated that "for selection of the right chemical product [original emphasis], the operators have so far only focused on the technical problem and functional test data have been the only criteria. Only after special requests from the authorities [have] potential environmental effects data ... been searched for" (Reiersen 1990). This is less true in the United States, partly because environmental regulations or regulatory attention at the State and Federal level has spurred attention and investment on the part of at least some operators. In some cases, successful operators have found that the increased attention paid to environmental management has increased overall efficiency. For example, at the First International Symposium on Oil and Gas Exploration and Production Waste Management Practices, sponsored by EPA in 1990, a number of speakers cited chemical inventory and training programs as having provided significant benefits, both economic as well as to human health and the environment.

The American Petroleum Institute surveyed a cross-section of its members in 1991 to develop information on waste minimization practices (broadly, the first two of the four categories above) currently implemented in routine operations. API also conducted a literature survey to augment member companies' information. API recognized the hierarchy established by EPA in the resulting compendium of practices--indeed, the cover of the report cited each of the categories (API 1991).

Waste minimization, whether through source reduction or recycling, can be an attractive objective to exploration and production companies, and service companies, because it lowers treatment and disposal costs and reduces the potential for future liability resulting from waste mismanagement. At the same time, however, it may require the use of more expensive or less suitable materials or require changes in processes or operations.

Of all the associated wastes, completion and workover fluids are most like drilling fluids in their relatively high potential for source reduction and recycling. They have received less attention than drilling fluids, perhaps because of the lower volumes at which they are generated and perhaps because they are typically either managed with drilling fluids or injected with produced water. API (1991) addressed drilling fluids and completion and workover fluids together and noted that there were significant opportunities for both source reduction and recycling.

Volume Reduction

Perhaps the most basic technique to reduce volumes of waste fluids that are managed in pits or other land units is to divert run-off, rigwash, and other such liquids from the pit. If allowed to enter the pit, the water becomes a waste that must be managed.

When fluids with environmental contaminants are managed with more benign wastes, the entire contents can become contaminated and either require more expensive management methods (Spell et al. 1990) or cause more environmental problems. Central Gulf Coast case studies evaluated a "Pit Management System," in contrast to the more conventional reserve pit or a closed system. In summary, a managed pit system may consist of several pits or bermed cells surrounded by a raised berm or levee. The system allows individual waste streams to be segregated and managed according to their special characteristics (drilling wastes were the paper's topic, but the concept could apply equally to completion and workover wastes managed in pits or other units). By preventing certain wastes from contaminating other wastes, significant cost savings were achieved in the case studies examined (Spell et al. 1990).

For drilling fluids, closed-loop mud systems were developed to allow reduced or no discharge of muds. Because low solids content is critical to completions and workovers, the concept is applicable to completion and workover fluids as well. By filtering or otherwise removing solids from circulating fluids, the fluid requires less frequent dilution or replacement and thus reduces the ultimate amount of waste (Thurber 1990, API 1991).

In addition, continuous mixing of fluids can reduce spillage as well as the amount of unused chemicals that must be disposed (Geehan et al. 1990). Continuous mixers were developed to improve fracturing treatments by allowing all the components of polymer slurries (e.g., potassium chloride, dry polymer in diesel, and water) to be mixed as they are pumped rather than being partially or completely premixed. This reduces the amount of fluid prepared for fracturing treatments, since there are no unused preblended fluids left in frac tanks--Gulbis (1988), for example, indicated that at least 7 percent of preblended fluids are left in frac tanks after typical fracturing treatments, so this is a substantial reduction. It also reduces the use of drums and sacks, since units are typically trailer-mounted (e.g., Dowell-Schlumberger's PCM--Precision Continuous Mixer--unit). This eliminates the need to dispose of these containers and their residual chemicals. Finally, because bacteria from mix waters can begin to degrade polymers as soon as mixing occurs, the elimination of premixing reduces the need for bactericides. (Geehan et al. 1990)

Toxicity Reduction

Page and Chilton (1991) of Anadrill/Schlumberger identified the replacement of metal-containing pipe dope compounds with nonhazardous lithium-based grease with microsphere ceramic balls as one case where a more benign substance could be substituted.

Increasing attention is being paid to reducing the quantities of drilling muds as well as reducing the toxicity of muds and additives. Although little information specific to completion/workover fluids was located, much of the experience gained with muds may be applicable (and possibly is being applied) to completion/workover fluids, since additives are often common to muds and to completion/workover fluids; where drilling muds (either as used or modified) are used as completion fluids, the experience is directly applicable. Thurber (1991), for example, describes a number of substitute chemicals for use as thinners, corrosion control additives, and biocides, each of which demonstrates lower toxicity; API (1991) cited the same substitutes. Geehan et al. (1991) also describe changes from oil- to water-based muds and reducing mud discharges, which reduced waste quantity and toxicity and also was cost-effective. At least partly in response to EPA Region VI requirements that bioassay testing be conducted on drilling fluids, additive screening and product substitution by Bray (1989, cited in Thurber 1990) led to substantial decreases in mud toxicity (as measured by increasing LC50s for fluids) within a short period of time.

Himes and Vinson (1991) described a recent substitute chemical that they describe as more environmentally benign as used. Traditionally, various salts (potassium chloride, sodium chloride, ammonium chloride, calcium chloride) have been used as temporary clay stabilizers during drilling, completion, and well servicing (i.e., workovers). The salts are mixed into water-based fluids in tanks prior to being pumped down the well: dry salt is poured into a tank where the water is being continually "rolled" by pumps. An excess of salt water is usually prepared simply to ensure a sufficient supply and the excess must be disposed. Its chloride content is typically too high for on- or off-lease land disposal (e.g., by landspreading or roadspreading). Himes and Vinson reported that organic clay stabilizers (singular organic cations similar but smaller than cationic organic polymers now used for permanent clay stabilization) were as effective as the salts in stabilizing formation clays. This organic stabilizer (whose composition was not described) is a liquid and can be injected into fluids with no need for pre-mixing. Thus, there is less excess fluid that must be managed as a waste. At recommended usage, the solutions were described as "nontoxic and biodegradable," unlike the salt solutions.

Per unit, oil-based fluids are more toxic as well as more costly than water-based fluids. This has spurred significant attention on the replacement of oil-based fluids with water-based. Indeed, as with drilling muds, the purpose of many of the additives used in completion/workover fluids is to reduce or overcome damage that water can do to the formation. On the other hand, Thurber (1990) points out that using oil-based fluids may be a means of pollution prevention in some cases: solids may be more manageable with oil-based fluids, more care is given to such fluids because of their cost (thus reducing spills), and they are generally more stable and thus more amenable to reuse.

Recycling/Reuse

In maintaining low solids in circulating completion and workover fluids (and thus minimizing formation damage), continuous filtering and other solids control methods allow fluids to be used without periodic replacement. This, for individual wells, would constitute "recycling" or "reuse." In addition, some fluids may be amenable to reuse in other completions/workovers. Prepared brines and oil-based fluids, simply

because of their cost, are often reused if they are carefully handled during operations (e.g., solids control) and reconditioned as necessary (e.g., with fresh additives). API (1991) reports a growing trend toward segregating and reusing completion/workover fluids.

It may also be possible to reclaim some specific additives (e.g., xylene used to dissolve scale) from recovered fluids, but no information on such practices was obtained. It should be noted that circulated fluids, as well as the first fluids that flow back from wells, may retain some of their treatment efficacy; they may be segregated into components and reused. Because injection wells may require as many or more frequent treatments than do producing wells, the injection of "spent" but partially effective treatment fluids also could constitute a beneficial reuse.

5.0 SUMMARY AND CONCLUSIONS

This chapter briefly summarizes many of the major themes that recur throughout this report and presents a few broad conclusions. Finally, a number of approaches to information collection that could prove fruitful in better characterizing the universe of completion and workover wastes are suggested.

Major themes that appear in various sections of the report and tentative findings that are suggested by the data include:

- Completion and workover operations are extremely variable, as is true of most exploration and production activities. The operations performed, materials used, wastes generated, and the means by which wastes are managed, are each superficially similar. In their important details, however, they show enormous variation, much of it driven by site-specific conditions and the particular regulatory environment in which exploration and production activities occur. No comprehensive data exist that even delineate the extremes of operations, materials, wastes volumes and characteristics, and management methods. Because such situation-specific variability exists, it is extremely difficult to draw broad conclusions. Notwithstanding the difficulty, a number are suggested below.
- A wide variety of materials are used in completion and workover fluids, many of them known to be toxic and many others of unknown toxicity. The use of any particular material is largely dependent on site-specific conditions, including economics. Because the fluids and other wastes are often not managed alone, any potential impacts from their management are likely to be disguised by other materials (or similar materials from other operations) and in most circumstances any impacts are sufficiently diluted to be unremarkable or untraceable to completion and workover wastes.
- The range of wastes that may be generated by completion and workover operations includes most of the drilling- and production-related associated wastes other than gas dehydration and sweetening wastes. Approaches that address particular operations (e.g., drilling, directional drilling, slimhole drilling) contrast with approaches that address specific wastes (e.g., workover fluids, clear brine workover fluids) or specific management methods (e.g., pits, injection) or particular areas (e.g., California, Kern County). The wide variability in each of these topics suggests that narrowly focussed study topics could be valuable in identifying and filling data gaps. Clearly, priorities would have to be established in order to select narrowly focussed topics that were "important" from a waste or waste management perspective.
- The oil and gas exploration and production industry, and particularly the service industry that is responsible for many or most completions and workovers, is not one in which the body of

knowledge is formal and written. Rather, information (particularly the details) is often closely guarded or otherwise transferred informally. In such a situation, narrowly focussed studies could materially advance the body of knowledge if properly directed and implemented.

- The American Petroleum Institute survey of associated wastes provides valuable information on the rough proportions of specific wastes managed using various methods. It suffered from a number of shortcomings in survey design (e.g., no explicit provision for reporting on-site or commercial injection of completion and workover fluids) and statistical rigor (e.g., using proportional oil production as the sole extrapolation factor with no sensitivity analysis). Perhaps as importantly, it is outdated. A more carefully designed survey instrument, perhaps targeted to narrower topics (e.g., specific wastes or specific practices), could be extremely beneficial.
- There has been increasing attention paid to the use of less toxic materials, focussed primarily on drilling muds. In some cases there have been increased operational efficiencies associated with more benign materials. Regulatory attention--in the United States offshore industry, Canada, and the North Sea, particularly--has quickened the pace of research. Many of the "advances" should be directly transferable to completion and workover fluids, although it is not clear that such transfers have occurred.

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APPENDIX A

**Volumes and Types of Fluids Used
in Oil and Gas Well Treatments**

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-1. Basic Matrix Acidizing Treatment of Main Pass Offshore Wells

Stimulation Design	Volume (gal/foot of formation to be treated)	Purpose
a. Three-stage preflush: prepare formation for mud acid		
1. Xylene solvents (or 75% xylene, 25% toluene)	1. 25	1. Dissolve paraffin on formation
2. 10 % acetic	2. 30 - 50	2. Dissolve carbonate near wellbore and establish low-pH buffer
3. 10 % hydrochloric	3. 50 - 100	3. Flush and dissolve calcium minerals
b. One-stage mud acid: 7.5 % HCl, 1.5 % HF	100 - 150	Main acid stage: dissolve clay and feldspar
c. Two-stage overflush: push spent acids and precipitates away from wellbore		
1. 3 % ammonium chloride water	1. 10 - 150	1. Transport spending acids deeper into formation
2. Xylene solvents	2. 25	2. Break down diverter to allow faster cleanup
Additives	Concentration (%)	Type
Acid	As shown above	As indicated above
Diverter	1 - 3	Oil-soluble resin; assist in uniform placement of acid over perforated interval
Corrosion inhibitor	0.1	Organic; used uniformly in acid stages for metal protection
Surfactants	0.5	Nonionic; used in acid stages to reduce/break emulsions from acid-formation fluid contact
Iron sequestrant	0.6 0.5	EDTA or Erythroic acid; at HCl stage to stabilize dissolved iron, minimize precipitation
Mutual solvent	10	EGMBE; restore formation wettability, reduce surface tension of returning acids
Clay stabilizer	2	Polyquaternary amine
SOURCE: Coulter et al. 1976		

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-2. Types and Volumes of Acid Fracturing Treatments on Gas Wells**

Treatment stage/fluid	Components	Quantity
Case History 1: production increase from 500 to 6,000 MCFD		
1. Acid	Alternating pad and acid treatments, repeated six times	1. Not specified
2. High-viscosity fracture fluid pad volume		2. Water with 300 lb guar, 10 lb silica flour, some with 1-3 lb/gal sand
3. Acid		3. 20 % HCl, 7% formic
4. Overflush with fluid to displace live acid to proper distance		4. Not specified
Case History 2: production increase from "only a show" to 1,000,000,000 ft ³ /day		
1. Acid	Alternating pad and acid treatments, repeated twelve times	1. Not specified
2. High-viscosity fracture fluid pad volume		2. Water with guar at 60 lb/1000 gal, sand at 2 lb/gal
3. Acid		3. Retarded 20 % HCl
4. Overflush with fluid to displace live acid to proper distance		4. Not specified
SOURCE: Coulter et al. 1976		
Five Kansas gas wells: production increase from 0 to 250 Mcf before treatment to 500 to 2,500 Mcf		
1. Cleanout acid, ball sealers for 50% of perforations; then swab and test or knock off balls	1. Not specified	1. Not specified
2. Preflush	2. 2.8 lb NaCl/gal, 20 lb gel/1,000 gal (for increased density and viscosity)	2. 2,000 - 3,000 gallons
3. Retarded acid	3. HCl (% unspecified)	3. 2,500 - 3,000 gallons
4. Densified flush	4. Unspecified gelling at unspecified rate per 1,000 gal	4. 2,000 - 3,000 gallons
5. Acid	5. HCl (% unspecified)	5. 2,000 - 3,000 gallons
6. Flush with fresh water or overflush about 10 bbl		
SOURCE: Frederickson and Broaddus 1975		

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Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE A-3. Types and Volumes of Fluids Used in Matrix Acidizing, Gulf Coast and Offshore Louisiana	
Stages and Fluids Used	Volume/Rate of Fluid
"Severely damaged" oil well, Texas Gulf Coast: production increase from 10 to 684 bbl/day (and from gas lift to flowing)--6 ft interval treated	
1. 12 % HCL 2. 3% HF, 12% HCl 3. Diesel and acid mutual solvent	1. 150 gallons 2. 500 gallons 3. 500 gal diesel, 10% EGMBE
Severely damaged oil well, Texas Gulf Coast: production increase from 0 to 380 bpd	
Treatment 1 (no effect) 1. 3% HF, 12% HCl treatment 2. Diesel oil and acid-mutual solvent afterflush	1. 200 gal/ft 2. 110 gal/ft diesel, 15% EGMBE
Treatment 2 (effective) 1. 3% HF, 12% HCl 2. Diesel oil Acid-mutual solvent	1. 400 gal/ft 2. 600 gal/ft diesel, 10% EGMBRE
Deep oil wells, South Louisiana	
Well 1: increase from 143 to 561 bpd 1. 15% HCl preflush 2. 3% HF, 12% HCl treatment 3. Diesel and acid-mutual solvent afterflush	1. 200 gallons 2. 1,500 gallons 3. 500 gallons diesel, 150 gallons EGMBE
Well 2: from 101 to 90 bpd (decline) 1. 15% HCl preflush 2. 3% HF, 12% HCl treatment 3. Diesel afterflush	1. 750 gallons 2. 1,500 gallons 3. 1,500 gallons diesel (no acid mutual solvent)
Offshore Louisiana well gravel pack treatment: production increase from 433 to 1,031	
1. 15% HCl 2. 3% HF, 12% HCl 3. Diesel and mutual solvent afterflush	1. 1,000 gallons 2. 1,000 gallons 3. 1,000 gallons diesel, 11% EGMBE
SOURCE: Gidley, 1970	

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TABLE A-4. Types and Volumes of Fluids Used in Acid Fracturing
Oil Wells, Wyoming

Fluid	Additives	Quantity (gallons)	Description of Treatment
Well 165: Acid fracturing at initial completion			
28% gelled HCl	Not described	15,000	Fracturing: two alternating water-acid stages followed by linear gelled water
Cross-linked gelled water	Hydroxypropyl guar polymer (18.1 kg per 1,000 gallons water)	10,000	
Linear gelled water	18.1 kg unspecified gel per 1,000 gal water	2,000	
Well 165: Acid refracture			
Linear gelled water	9.1 kg unspecified gel per 1,000 gal water	65,000	Three alternating water-acid stages treatments followed by three water and two HCl stages in succession (CO ² used in all but last water stage)
External oil-emulsion acid	28% HCl (70% by vol), diesel (30%)	80,000	
15 % HCl	Not described	12,300	
Well 180: Acid fracturing at initial completion			
28% gelled HCl	Not described	15,000	Two alternating water-acid stages followed by linear gelled water (CO ² used in all but last water stage)
Cross-linked gelled water	Hydroxypropyl guar polymer (18.1 kg per 1,000 gallons water)	10,000	
Linear gelled water	18.1 kg unspecified gel per 1,000 gal water	2,000	
Well 180: Acid refracture			
Linear gelled water	9.1 kg unspecified gel per 1,000 gal water	75,000	Three alternating water-acid stages treatments followed by one water and one HCl stage in succession
External oil-emulsion acid	28% HCl (70% by vol), diesel (30%)	70,000	
15 % HCl	Not described	15,000	

(continued)

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-5. Types and Volumes of Fluids Used in Acid Fracturing
and Refracturing Oil Wells, Wyoming
(continued)**

Fluid	Additives	Average Quantity (gallons)	Description of Treatments
Five wells: Acid fracturing at initial completion (including wells 165 and 180 above)			
Linear gelled water	9.1 or 18.1 kg unspecified gel per 1,000 gal	67,500 (4 wells)	Unspecified number of alternating water-acid stages followed by water and conventional HCl stages in succession
External oil-emulsion acid	28% HCl (70% by vol), diesel (30%)	73,600 (all wells)	
Cross-linked gelled water	9.1 or 18.1 kg unspecified gel per 1,000 gal	61,000 (4 wells)	
15% HCl	Not described	30,000 (1 wells)	
Eleven wells: Acid refracturing (including wells 165 and 180 above)			
Linear gelled water	9.1 to 18.1 kg unspecified gel per 1,000 gal	95,400 (11 wells)	Unspecified number of alternating water-acid stages treatments followed by water (and for some wells, conventional HCl) stages in succession
External oil-emulsion acid	28% HCl (70% by vol), diesel (30%)	68,000 (11 wells)	
Cross-linked gelled water	9.1 to 18.1 kg unspecified gel 1,000 gal	45,000 (2 wells)	
15% HCl	Not described	12,200 (6 wells)	
SOURCE: Aud et al. 1992			

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**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-6. Types and Volumes of Fluids Used in Hydraulic and Acid
Fracturing Treatments, Oklahoma County, Oklahoma**

Fluid/material	Treatment rate	Total volume	Treatment
"Kiel" dendritic hydraulic fracturing: 15 wells (up to 20-fold production increase)			
15% HCl	Not specified	5,000 gallons	Four-stage treatment: acid preflush followed by six divertant/fluid loss events (sand in slick water) altered with six slick water pad fluid events. Additives, if any, not specified.
Fresh water (slick water)	75 - 100 bbl per interval foot	6,000 bbl	
Sand	1-4 lb per gallon water	32,000 lb 20/40 mesh 32,000 lb 100 mesh	
Pad/acid staged fracturing process: unspecified number of wells (up to 10-fold increase)			
Gelled pad fluid	15 - 30 bbl/ft	Not specified	Generally, four- or five-stage treatment with alternating pad-acid treatments. In some, sand injected ahead of pads to divert acid. Additives not specified.
Gelled or retarded HCl	7.5 - 15 bbl/ft	Not specified	
SOURCE: Wilke et al. 1991			

US EPA ARCHIVE DOCUMENT

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-7. Types and Volumes of Fluids Used for Iron Control Treatments
in Sour-Gas Wells, Texas

Fluid	Volume	Purpose
Case 1 (oil): production increase from 1 to 30 BOPD, 5 to 20 BWPD		
Clay-stabilizing water	1,000 gallons	Stabilize formation clays
15% iron-control HCl	1,500 gallons	Tubing cleanout: remove scale prior to acid treatment of formation. Unspecified iron-chelating additive.
Sour-well iron-control acid (unspecified)	1,500 gallons	Acid treatment of formation. Included 90 lb/gal unspecified diverter. Unspecified iron-chelating additive.
Clay-stabilized water	500 gallons	Overflush.
Case 2 (gas): production increase from 0 to 400 Mcf/day and 250 BWPD after six months		
Sour-well iron control	3,000 gallons	Tubing cleanout: remove scale (and possibly treat formation). Unspecified iron-chelating additive. Other fluids, if any, not described.
Case 4 (gas): production increase from 3 to 4 (maximum allowable) MMcf/D after three months		
Acetic acid	3,000 gallons	Not described. Presumably, tubing cleanout (scale removal) and possibly formation treatment, respectively.
Sour-well iron-control acid	4,000 gallons	
NOTE: Source did not provide volumes for Case 3.		
SOURCE: Walker et al. 1991		

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-8. Types and Volumes of Fluids Used for Fracturing,
Oklahoma and Illinois Examples**

Fluid/Material	Specifications	Volume	Treatment
Tight gas well, Oklahoma ^A			
Gelled water	2% KCl	15,000 gallons	Treatment design not described. Volume described as "fairly typical" for area
Sand proppant	20/40 mesh	20,000 lb	
Oil well (two intervals completed), Illinois (post-1989) ^B			
HCl	15%	3,500 gallons	Breakdown treatment
Crosslinked gelled water	Not described	31,000 gallons	Fracturing
HCl	15% and 20%	15,000 gallons	Not described
HCl	15%	2,500 gallons	Breakdown treatment
Crosslinked gelled water	Not described	15,000 gallons	Fracturing
HCl	15% and 20%	8,000 gallons	Not described
Several (unspecified number) oil well completions, Illinois (pre-1989) ^B			
Nitrogen/gelled water foam	75 quality	60,000 gallons	"Average" treatment for wells in field, otherwise undescribed
Sand	12/20 or 20/40 mesh	60,000 - 80,000 lb	
<p>SOURCES: A Syfan and Robinson 1992 B Baker and Carlisle 1992</p>			

US EPA ARCHIVE DOCUMENT

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-9A. Components of Acid Fracturing Fluid Used on Two Oil Wells In South Texas
Producing From A Carbonate Formation**

Material	Application	Components	Hazardous Characteristic If Regulated Under Subtitle C
Treatment: about 32,000 bbls fresh water with 15% HCl. Additives included those below.			
Hydrochloric Acid (Inhibited)	Solvent/acidizing agent	Hydrochloric Acid	Corrosivity
Acid Inhibitor	Corrosion Inhibitor	Propargyl Alcohol, Isopropanol, Dimethyl Formamide, Quaternary Ammonium Salt, Benzyl Chloride	Ignitability
Non-emulsifier	Non-emulsifier	Isopropanol, Aromatic Naphtha, Amines, Rosin, Quaternary Ammonium Compounds	Ignitability
Friction Reducer	Friction Reducer	Ammonium Chloride, Ethoxylated Amylphenol, Paraffinic/Naphthenic Solvent	None
Non-emulsifier	Cationic Non-emulsifier	Methanol, Quaternary Aryl Fatty Amine	Ignitability
Diverting Agent	Diverting Agent	Hydrocarbon Polymer/Wax Blend	None
Sand, 20/40 mesh	Proppant	Silica, Crystalline Quartz	None
SOURCE: U.S. EPA, 1992			

US EPA ARCHIVE DOCUMENT

<p align="center">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE A-9B. Components of Acid Treatment Fluid Used on Oil Well In Northwest Texas</p>			
Material	Application	Components	Hazardous Characteristic If Regulated Under Subtitle C
<p>Treatment: pumping 300 gallons of aesol and 300 gallons of xylene, plus 4,800 gallons of 20 percent hydrochloric acid mixed with micellar aesol and 1,500 gallons of Na₃ Monohydrate and corrosion inhibitor, followed by 40 barrels of produced water with four gallons of soap. The formation was then perforated. The operator swabbed back 55 barrels of fluid and repeated the acid treatment. Additives included those below.</p>			
Hydrochloric Acid	Solvent	Hydrochloric Acid	Corrosivity, Reactivity
Micellar Aesol	Cleaning	Methanol, Isopropanol, Methylisobutyl carbinol, Alkyl ether sulfate, ammonium salt, Liquid citric acid, Alkyloxylated surfactants	Ignitability
Corrosion Inhibitor	Corrosion Inhibitor	Acetylenic alcohols, Quaternary amines in mixed aromatic and oxygenated solvents, Methanol	Ignitability
Na ₃ Monohydrate	Cleaning (chelating agent)	Trisodium nitrilotriacetate, Monohydrate	None
<p>Source: U.S. EPA, 1992.</p>			

US EPA ARCHIVE DOCUMENT

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-9C. Components of Fracturing Fluid Used on Gas Well in Northwest Oklahoma

Material	Application	Components	Hazardous Characteristic If Regulated Under Subtitle C
Treatment: well fractured using carbon dioxide (CO ₂) and gelled water. Additives included those below.			
Hydrochloric Acid	Solvent	Hydrochloric Acid	Corrosivity, Reactivity
Clay (A)	Preflush - Clay Stabilizer	Quaternary Ammonium chloride	None
Gelling Agent	Water gelling	Galacto-Mannan Gum	None
Peroxide	Oxidizer	Ammonium Peroxidisulfate	Corrosivity
Fluid Loss Agent	Fluid loss control	Carbohydrates	None
Fluid Loss Agent	Fluid loss control	Aromatic and alcohol solvents, surfactant	Ignitability
Frac Foam	Foaming agent	Methanol, Amphoteric surfactant	Ignitability
Methanol	Cleaning	Methyl Alcohol	Ignitability
Ethyoxylated Surfactant	Foaming agent	Isopropanol, heavy aromatic petroleum solvent, methylisobutylcarbinol	Ignitability
Clay (B)	Clay Stabilizer	Methanol, cationic polymer	Ignitability
Citric Acid	Iron control	2 Hydroxyl-1,2,3 propane tricarboxylic acid	None
Surfactant	De-emulsifier	Xylene, methanol, isopropanol, heavy aromatic naphtha	None
Proppant	Proppant		
Source: U.S. EPA, 1992.			

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**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-10. Fluids Used in 32 Staged Acid Treatments of Sandstone
Formations**

Fluid/component	Volume (gal/foot of perforations)	Purpose
32 wells in sandstone formations in AK, CA, Gulf of Mexico		
Solvent	10 - 50 gal/ft	Preflush to reduce intensity of oil/acid emulsions in formation and downstream
HCl	20 - 75 gal/ft	
HCl:HF	40 - 150 gal/ft	
Ammonium chloride (3%)	50 - 250 gal/ft	Brine displacement overflush--may have contained various additives
SOURCE: Dunlap and Houchin 1990		

US EPA ARCHIVE DOCUMENT

<p align="center">Associated Waste Report: Completion and Workover Wastes (U.S. EPA, January 2000) TABLE A-11. Acid Treatments in California (Stevens formation)</p>	
Well A-1: Treatment obstructed wellbore with asphaltene sludge, could not be returned to production	Well A-2: Oil production more than doubled
15% HCl Corrosion inhibitor Erythorbic acid Nonemulsifier 2% anti-sludge agent 12:3 HCl:HF Corrosion inhibitor Erythorbic acid Nonemulsifier 2% anti-sludge agent 3% NH ₄ Cl post-flush	10% acetic acid Corrosion inhibitor Nonemulsifier Erythorbic acid 7.5:1.5 HCl:HF Corrosion inhibitor Nonemulsifier Erythorbic acid 3% NH ₄ Cl post-flush
SOURCE: Houchin et al. 1990	

Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE A-11. Suggested Acid Use in Matrix Acidizing

Type of treatment	Suggested acid use (% by weight)
Carbonate acidizing	
Perforating fluid	5 % acetic
Damaged perforations	9 % formic 10 % acetic 15 % HCl
Deep wellbore damage	15 % HCl 28 % HCl Emulsified HCl
Sandstone acidizing	
High HCl solubility (< 20%)	HCl only
High permeability (> 100 md)	
High quartz (80%), low clay (< 5%)	12% HCl and 3% HF
High feldspar (> 20%)	13.5% HCl and 1.5% HF, preflush of 15% HCl
High clay (%)	6.5% HCl and 1% HF, preflush of sequestered 5% HCl
High iron chlorite clay	6.5% HCl and 1% HF, preflush of sequestered 5% HCl
Low permeability (< 10 md)	
Low clay (< 5%)	6% HCl and 1.5% HF, preflush of 7.5% HCl or 10% acetic
High chlorite	3% HCl and 0.5% HF, preflush of 5% acetic
SOURCE: McLeod, H.O., L.B. Ledlow, and M.V. Till. 1983. "The Planning, Execution, and Evaluation of Acid Treatments in Sandstone Formations. SPE Paper 11931. Cited in: H.O. McLeod, Jr. "Matrix Acidizing. <i>Journal of Petroleum Technology</i> (December 1984).	

APPENDIX B

Number of Oil and Gas Well Stimulations, 1982, 1985, and 1987

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
TABLE B-1. Number of Oil and Gas Wells Treated by Acidizing and Chemical Treatments
and by Hydraulic Fracturing**

State	Number of Oil and Gas Well Treatments								
	Acidizing and other chemical treatments (A)			Hydraulic Fracturing (A)			Total (B)		
	1982	1985	1987	1982	1985	1987	1982	1985	1987
Alabama	300	240	200	300	300	300	600	540	500
California	6,400	4,840	3,800	4,000	3,760	3,600	10,400	8,600	7,400
Colorado	2,600	2,000	1,600	2,500	1,660	1,100	5,100	3,660	2,700
Florida	(C)		(C)	(C)		(C)			
Illinois	3,200	2,060	1,300	(C)		800			2,100
Kansas	4,800	3,660	2,900	2,600	1,880	1,400	7,400	5,540	4,300
Louisiana	11,000	8,300	6,500	10,700	8,180	6,500	21,700	16,480	13,000
Michigan	9,900		(C)	(C)		(C)			
Mississippi	(C)		600	(C)		800			1,400
Montana	(C)		300	(C)		(C)			
Nevada	(C)		(C)	(C)		(C)			
New Mexico	4,300	3,160	2,400	4,300	2,620	1,500	8,600	5,780	3,900
New York	(C)		< 500	(C)		(C)			
North Dakota	1,000	940	900	1,000	700	500	2,000	1,640	1,400
Ohio	2,300	1,400	800	3,200	2,420	1,900	5,500	3,820	2,700
Oklahoma	13,600	10,840	9,000	12,900	8,460	5,500	26,500	19,300	14,500

(continued)

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)**
**TABLE B-1. Number of Oil and Gas Wells Treated by Acidizing and Chemical Treatments
and by Hydraulic Fracturing**
(continued)

State	Number of Oil and Gas Well Treatments								
	Acidizing and other chemical treatments (A)			Hydraulic Fracturing (A)			Total (B)		
	1982	1985	1987	1982	1985	1987	1982	1985	1987
Pennsylvania	(C)		(C)	1,900	1,600	1,400			
Texas	34,600	26,860	21,700	25,500	20,220	16,700	60,100	47,080	38,400
Utah	1,300	820	500	1,100	740	500	2,400	1,560	1,000
West Virginia	NA		(C)	NA		1,400			
Wyoming	5,000	2,780	1,300	3,300	2,040	1,200	8,300	4,820	2,500
Total U.S.	101,600	76,100	59,100	84,100	63,040	49,000	185,700	139,140	108,100

NOTES:
 A 1982 and 1987 figures for Acidizing and Hydraulic Fracturing were taken from source; 1985 totals are linear interpolations of 1982 and 1987 figures [1982 value + (0.4 * (1987 value - 1982 value))]. 1982 and 1987 totals are reported in source to the nearest hundred and thus are accurate to within ± 50. The interpolated 1985 value should be accurate to ± 50 as well. No figures are presented for 1985 when both 1982 and 1987 figures were not presented in source.
 B Figures for total treatments are the totals of figures in appropriate Acidizing and Hydraulic Fracturing columns. No figures are presented when source did not provide figures for both columns to be .
 C Withheld by source to avoid disclosing data for individual companies
 NA Not available

SOURCE: U.S. Department of Commerce, 1990

APPENDIX C

Analytical Results of EPA 1992 Sampling Program (Detected Analytes Only)

Workover and Completion Wastes

**Associated Waste Report:
Completion and Workover Wastes (U.S. EPA, January 2000)
Table C-1. General Chemistry**

<i>FACILITY</i>		G	I	I	L	M	O	S
<i>SAMPLE NUMBER</i>	<i>AQUEOUS</i>	23167	23174	23175	23628	23631	23639	23652
<i>ANALYTE</i>	<i>UNIT</i>							
Acidity	mg/L CaCO3	ND	NA	ND	1350.0	2580.0	NA	4120.0
pH	std. units	6.53	6.35	6.63	3.61	4.67	NA	6.29
Carbon, total organic	mg/L	94.0	546400.0	ND	7080.0	NA	NA	6020.0
Chloride	mg/L	14426	NA	15214	157000	77300	NA	25600
Corrosivity	mmpy	ND	NA	ND	0.1	1.8	NA	ND
Cyanide, Total	mg/L	ND	ND	ND	ND	ND	0.052	ND
Flashpoint, closed cup	deg. F	>140	ND	>140	98.0	>210	NA	210.0
Fluoride	mg/L	2.25	NA	2.06	ND	ND	NA	0.65
Nitrogen, ammonia	mg/L	12.3	NA	15.3	163.0	742.0	NA	ND
Nitrogen, Nitrate+Nitrite (3)	mg/L	0.697	NA	0.572	2.13	ND	NA	ND
Oil & Grease, Total	mg/L	15.0	8140.0	30.8	722.0	159.0	NA	18200.0
Oxygen Demand, Biochemical 5-day Tot.	mg/L	125.0	NA	142.0	17000	3030.0	NA	1500.0
Oxygen Demand, Chemical	mg/L	475.0	NA	500.0	21750.0	38275.0	NA	20915.0
Phenols	mg/L	1.530	0.097	1.450	1.050	ND	NA	0.180
Salinity	Salinity #	26.8	NA	32.4	160.7	121.8	NA	49.6
Solids, Total Dissolved	mg/L	24406	NA	28722	368880	136670	NA	19380

Continued

Associated Waste Report:
 Completion and Workover Wastes (U.S. EPA, January 2000)

Table C-1. General Chemistry
 (Continued)

<i>FACILITY</i>		G	I	I	L	M	O	S
<i>SAMPLE NUMBER</i>	<i>AQUEOUS</i>	23167	23174	23175	23628	23631	23639	23652
<i>ANALYTE</i>	<i>UNIT</i>							
Solids, Total Suspended	mg/L	65.5	NA	226.0	1620.0	170.0	NA	14000.0
Specific Conductance	umhos/cm	37700	NA	44600	NA	NA	NA	NA
Sulfate	mg/L	382.0	NA	212.0	766.0	1692.0	NA	236.0
Sulfide	mg/L	ND	NA	ND	5.3	31.1	NA	8.01
NA = Not Analyzed ND = No Detect								

Associated Waste Report:
 Completion and Workover Wastes (U.S. EPA, January 2000)

Table C-2. Metals

<i>FACILITY</i>	G	I	I	L	M	O	S
<i>SAMPLE:</i>	23167	23174	23175	23628	23631	23639	23652
<i>METAL</i>	ug/L	ug/L	ug/L	ug/L	ug/L	ug/L	ug/L
Aluminum	ND	1110.0	202.0	10300.0	13100.0	8740.0	7880.0
Antimony	ND	ND	ND	ND	ND	148	100
Arsenic	ND	15.0	ND	137.0	ND	693.0	66.8
Barium	784.0	121.0	1260.0	66.5	278.0	102.0	3360.0
Beryllium	ND	ND	ND	25.1	11.7	6.4	4.7
Boron	9040.0	ND	11200	45200	4930	4840	24500
Cadmium	8.1	27.9	7.6	15.1	51.5	48.1	82.3
Calcium	1190000	9060	1070000	28000000	14000000	7160000	3080000
Chromium	52.1	ND	48.0	779.0	1320.0	885.0	859.0
Cobalt	ND	ND	ND	ND	ND	40.9	46.5
Copper	ND	6070.0	6.8	192.0	27.2	1160.0	1780.0
Iron	7190	146000	9870	115000	906000	884000	1140000
Lead	ND	ND	ND	ND	ND	6880.0	907.0
Magnesium	10400	875	151000	13500000	7310000	4290000	245000

Continued

Associated Waste Report:
 Completion and Workover Wastes (U.S. EPA, January 2000)

Table C-2. Metals
 (Continued)

<i>FACILITY</i>	G	I	I	L	M	O	S
<i>SAMPLE:</i>	23167	23174	23175	23628	23631	23639	23652
<i>METAL</i>	ug/L	ug/L	ug/L	ug/L	ug/L	ug/L	ug/L
Manganese	356.0	1340.0	187.0	1190.0	18800.0	5200.0	16300.0
Mercury	ND	6	ND	ND	ND	ND	ND
Molybdenum	ND	285.0	ND	167.0	ND	148.0	48.3
Nickel	ND	510	ND	72	39	467	204
Selenium	ND	ND	30.4	ND	45.3	139.0	ND
Silver	ND	ND	ND	ND	8.0	ND	ND
Sodium	7170000.0	33900.0	8960000.0	14700000.0	18400000.0	45200000.0	9060000.0
Strontium	118000	104	192000	343000	39500	21100	90800
Sulfur	145000.0	99000.0	72600.0	89900.0	273000.0	646000.0	58300.0
Thallium	ND	ND	ND	ND	ND	67.3	ND
Tin	ND	189.0	ND	ND	ND	135.0	291.0
Titanium	ND	ND	ND	283.0	72.2	17.7	55.7
Vanadium	ND	90.1	ND	623.0	307.0	4850.0	155.0
Yttrium	ND	ND	ND	78.6	131.0	ND	8.4
Zinc	7.3	610.0	9.4	1330.0	468.0	ND	3610.0

ND = Non Detect NA = Not Analyzed

Associated Waste Report:
 Completion and Workover Wastes (U.S. EPA, January 2000)

Table C-3. Volatile Organic Compounds

<i>FACILITY</i>	G	I	I	L	M	O	S
<i>SAMPLE NUMBER:</i>	23167	23174	23175	23628	23631	23639	23652
<i>COMPOUND</i>	ug/L	ug/L	ug/L	ug/L	ug/L	ug/L	ug/Kg
ACETONE	ND	ND	ND	13508.0	902.0	273.0	99419.0
BENZENE	8561.0	14194.0	8542.0	477.0	2204.0	5077.0	>20000
ETHYLBENZENE	655.0	1938.0	588.0	2144.0	154.0	3597.0	>20000
METHYL CHLORIDE (CHLOROMETHANE)	ND	ND	ND	57.0	ND	ND	ND
METHYL ETHYL KETONE (2-BUTANONE)	ND	ND	ND	115.0	ND	81.0	ND
METHYLENE CHLORIDE	ND	ND	ND	ND	ND	24.0	ND
M-XYLENE	571.0	1767.0	667.0	3235.0	335.0	3490.0	671567.0
O- + P-XYLENE	318.0	2670.0	359.0	1619.0	161.0	1199.0	671567.0
TETRACHLOROETHYLENE	ND	ND	ND	ND	ND	69.0	ND
TOLUENE	6364.0	14166.0	6392.0	298.0	1484.0	2704.0	>20000
4-METHYL-2-PENTANONE	ND	ND	ND	5862.0	193.0	224.0	ND
ND = Non Detect NA = Not Analyzed							

Associated Waste Report:
 Completion and Workover Wastes (U.S. EPA, January 2000)

Table C-4. Semivolatile Organic Compounds

<i>FACILITY</i>	G	I	I	L	M	O	S
<i>SAMPLE:</i>	23167	23174	23175	23628	23631	23639	23652
<i>COMPOUND</i>	ug/L	ug/Kg	ug/Kg	ug/L	ug/L	ug/L	ug/L
BENZOIC ACID	8707	ND	7995	ND	ND	ND	ND
BENZYL ALCOHOL	5244	ND	5958	ND	ND	ND	ND
BIS(2-ETHYLHEXYL)PHTHALATE	ND	ND	ND	ND	ND	381	ND
DIBENZOFURAN	ND	ND	ND	136	138	1809	ND
DIBENZOTHIOPHENE	ND	ND	ND	222	ND	5666	ND
FLUORENE	ND	ND	ND	123	ND	1041	ND
HEXANOIC ACID	ND	ND	1289	ND	ND	ND	ND
NAPHTHALENE	4789	33050	4978	1050	ND	4379	ND
N-DECANE (N-C10)	10054	117824	40295	ND	550	ND	161455
N-DOCOSANE (N-C22)	2779	ND	5557	1304	237	42716	121990
N-DODECANE (N-C12)	13700	2382160	36819	ND	1152	ND	430966
N-EICOSANE (N-C20)	2951	ND	7402	ND	451	ND	125332
N-HEXACOSANE (N-C26)	1677	3939260	2993	789	173	3106	67777
N-HEXADECANE (N-C16)	8944	4398800	16577	ND	808	ND	360469
N-OCTACOSANE (N-C28)	2258	255672	1844	422	ND	18058	30457
N-OCTADECANE (N-C18)	3573	3183400	8134	1868	281	4457	337028
N-TETRACOSANE (N-C24)	2227	2731600	5569	1289	312	47224	82292
N-TETRADECANE (N-C14)	3998	4036000	9942	1961	513	5124	538421

Continued

Associated Waste Report:
 Completion and Workover Wastes (U.S. EPA, January 2000)

Table C-4. Semivolatile Organic Compounds

(Continued)

<i>FACILITY</i>	<i>G</i>	<i>I</i>	<i>I</i>	<i>L</i>	<i>M</i>	<i>O</i>	<i>S</i>
<i>SAMPLE:</i>	23167	23174	23175	23628	23631	23639	23652
<i>COMPOUND</i>	<i>ug/L</i>	<i>ug/Kg</i>	<i>ug/Kg</i>	<i>ug/L</i>	<i>ug/L</i>	<i>ug/L</i>	<i>ug/L</i>
N-TRIACONTANE (N-C30)	1070	236416	1523	ND	ND	5566	11655
O-CRESOL	8423	ND	6955	ND	ND	ND	ND
O-TOLUIDINE	ND	ND	ND	ND	ND	ND	ND
P-CRESOL	1307	ND	1505	ND	ND	ND	ND
P-CYMENE	ND	ND	ND	144	ND	11337	ND
PENTAMETHYLBENZENE	ND	ND	ND	108	ND	ND	ND
PHENANTHRENE	ND	32466	ND	128	ND	1726	ND
PHENOL	22074	ND	20380	255	271	ND	ND
1-METHYLFLUORENE	ND	107318	1985	163	ND	ND	ND
1-METHYLPHENANTHRENE	ND	66832	ND	ND	ND	ND	ND
2-ISOPROPYLNAPHTHALENE	ND	21164	ND	ND	ND	ND	ND
2-METHYLNAPHTHALENE	2172	179690	5095	1634	ND	10245	ND
2,4-DIMETHYLPHENOL	5438	ND	4555	ND	ND	ND	ND
3,6-DIMETHYLPHENANTHRENE	ND	152296	ND	ND	ND	ND	ND
ND = Non Detect NA = Not Analyzed							