Drilling Waste Management technology Descriptions

The Drilling Waste Management Information System is an online resource for technical and regulatory information on practices for managing drilling muds and cuttings, including current practices, state and federal regulations, and guidelines for optimal management practices.

Visitors can use this resource to:

- learn about industry standard practices;
- determine which regulatory requirements must be met;
- select optimal management strategies for their location and circumstances.

The Drilling Waste Management Information System was developed by Argonne National Laboratory and industry partners, ChevronTexaco and Marathon, under the U.S. Department of Energy's (DOE's) Natural Gas & Oil Technology Partnership program. Funding for the project was provided through DOE's National Energy Technology Laboratory.

Drilling Waste Management Technology Descriptions

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Drilling Waste Management Technology Descriptions

The first step in managing drilling wastes is to separate the solid cuttings from the liquid drilling mud. Once solid and liquid drilling wastes have been separated, companies can use a variety of technologies and practices to manage the wastes. For some applications, drilling wastes are solidified or stabilized prior to their ultimate management practice. The management technologies and practices can be grouped into three major categories: waste minimization, recycle/reuse, and disposal. Follow the links below to learn more about the specific technologies and practices in each category.

Introduction

Waste Minimization

Practices that can reduce volumes or impacts of wastes

- Drilling Practices That Minimize Generation of Drilling Wastes
  - Directional Drilling
  - Drilling Smaller Diameter Holes
  - Drilling Techniques That Use Less Drilling Fluid
- Using Muds and Additives with Lower Environmental Impacts
  - Synthetic-based Muds
  - New Drilling Fluid Systems
  - Alternate Weighting Agents

Recycle/Reuse

Practices that find another use for drilling wastes

- Beneficial Reuse of Drilling Wastes
  - Recycling Muds
  - Roadspreading
  - Reuse of Cuttings for Construction Purposes
  - Restoration of Wetlands Using Cuttings
  - Use of Oily Cuttings as Fuel

Disposal

Practices to get rid of drilling wastes

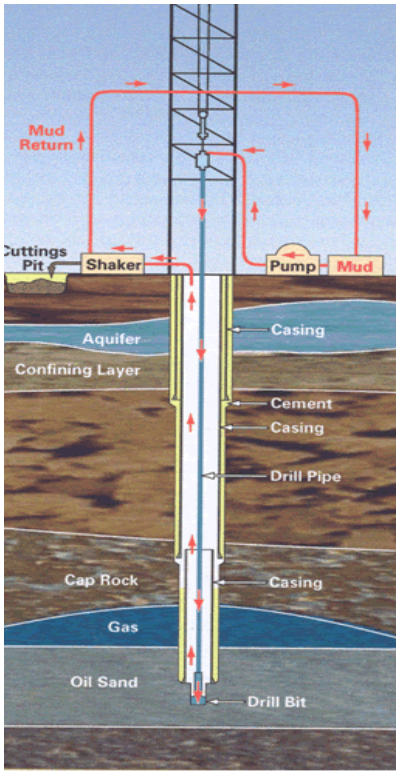
- Onsite Burial (Pits, Landfills)
- Land Application
  - Landfarming
  - Landspreading
- Bioremediation
  - Composting
  - Bioreactors
  - Vermiculture
- Discharge to Ocean
- Offsite Disposal to Commercial Facilities
- Slurry Injection
- Salt Caverns
- Thermal Treatment
  - Incineration
  - Thermal Desorption

Drilling Waste Management, Technology Descriptions

Fact Sheet - The First Step: Separation of Mud from Cuttings

Drilling mud is used to control subsurface pressures, lubricate the drill bit, stabilize the well bore, and carry the cuttings to the surface, among other functions. Mud is pumped from the surface through the hollow drill string, exits through nozzles in the drill bit, and returns to the surface through the annular space between the drill string and the walls of the hole.

Figure 1: Recirculation system.



As the drill bit grinds rocks into drill cuttings, these cuttings become entrained in the mud flow and are carried to the surface. In order to return the mud to the recirculating mud system and to make the solids easier to handle, the solids must be separated from the mud. The first step in separating the cuttings from the mud involves circulating the mixture of mud and cuttings over vibrating screens called shale shakers.

Figure 2: Drilling mud exiting flowline

The liquid mud passes through the screens and is recirculated back to the mud tanks from which mud is withdrawn for pumping down-hole. The drill cuttings remain on top of the shale shaker screens; the vibratory action of the shakers moves the cuttings down the screen and off the end of the shakers to a point where they can be collected and stored in a tank or pit for further treatment or management.

Figure 3 : Shale shakers removing cuttings from drilling mud

Often two series of shale shakers are used. The first series (primary shakers) use coarse screens to remove only the larger cuttings. The second series (secondary shakers) use fine mesh screens to remove much smaller particles. In general, the separated drill cuttings are coated with a large quantity of drilling mud roughly equal in volume to the cuttings.

Figure 4: Mud tank storage

Additional mechanical processing is often used in the mud pit system to further remove as many fine solids as possible because these particles tend to interfere with drilling performance. This mechanical equipment usually belongs to one of three types:

1) hydrocyclone-type desilters and desanders,

2) mud cleaners (hydrocyclone discharging on a fine screened shaker), and

3) rotary bowl decanting centrifuges. The separated fine solids are combined with the larger drill cuttings removed by the shale shakers.

Figure 5: Vertical cuttings dryer

Figure 6: Dried cuttings

If the solids collected by the shale shakers are still coated with so much mud that they are unsuitable for the next reuse or disposal step or if the used mud is valuable enough to collect as much of it as possible, the solids can be further treated with drying shakers utilizing high gravitational separation, vertical or horizontal rotary cuttings dryers, screw-type squeeze presses, or centrifuges. The cuttings dryers recover additional mud and produce dry, powdery cuttings.

Figure 7: Centrifuge

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Fact Sheet - Solidification and Stabilization

The cuttings separated from the mud at the shale shakers may be coated with so much mud that they are unsuitable for the next reuse or disposal step or are difficult to handle or transport. Constituents of the cuttings or the mud coating them (e.g., oil, metals) may leach from the waste, making them unsuitable for land application or burial approaches. Various materials can be added to cuttings to solidify and stabilize them. The processes of solidification and stabilization can be defined as follows:

Solidification refers to techniques that encapsulate the waste in a monolithic solid of high structural integrity. The encapsulation may be of fine waste particles (microencapsulation) or of a large block or container of wastes (macroencapsulation). Solidification does not necessarily involve a chemical interaction between the wastes and the solidifying reagents but may mechanically bind the waste into the monolith. Contaminant migration is restricted by vastly decreasing the surface area exposed to leaching and/or by isolating the wastes within an impervious capsule.

Stabilization refers to those techniques that reduce the hazard potential of a waste by converting the contaminants into their least soluble, mobile, or toxic form. The physical nature and handling characteristics of the waste are not necessarily changed by stabilization.

Types of Additives

Historically, cement, fly ash, lime, and calcium oxide have been used most frequently as solidification/stabilization additives for treating drill cuttings and other types of wet solids. A recent study tested seven other types of additives for stabilizing cuttings and assessing the performance of stabilized cuttings as a substrate for growing wetlands plants. These included: medium-ground mica-based material, fine-ground mica, three different commercial mixtures of recycled cellulose fibers, walnut nut plug, and pecan nut plug (Hester et al. 2003). Various other commercial products with proprietary compositions have been marketed.

Implementation Considerations

Not all drilling wastes are amenable to chemical fixation and stabilization treatments. Solidification/stabilization should be adapted for site-specific applications depending on the end-use of the treated material and the chemical characteristics of the waste. Conducting laboratory tests to determine the proper blend of additives to achieve the desired material properties is recommended.

Some companies have used solidification/stabilization for drilling wastes. The resulting materials have been used for road foundations, backfill for earthworks, and as building materials (Morillon et al. 2002) and may be used for other purposes (BMT Cordah Limited 2002).

In contrast to these examples, others (in particular, ChevronTexaco, one of the companies that partnered with Argonne to develop this website) have tested different additives and found that they either did not achieve the desired goals once the solidified or stabilized wastes were placed into the environment or that the cost of using the additives was prohibitive. Most of the solidification/stabilization systems produce conditions both of high pH and high total alkalinity. Much concern has been expressed about the long-term stability of the processes. Of greatest concern is the failure of the additives to keep the waste constituents from releasing into the environment over the long term or the sudden release of contaminants due to breakdown of the matrix. No long-term data are available because the technology has only been practiced for about 20 years, although ChevronTexaco has tested about 8 different commercial products and found that all failed leachate testing (Fleming 2000).

A solidified waste is an amorphous solid at least partially saturated with water. It consists of one or more solid phases, entrapped air in the form of air voids, and a liquid phase; all are in chemical equilibrium or close to it. When the solid is exposed to leaching conditions, equilibrium is disturbed. The leaching mechanisms assume that no chemical reactions occur (other than those involved in dissolution of the constituents in the solid). While this might be true in laboratory leaching tests, it is not the case in the real environment. Rain, surface water, and ground water all contain constituents that may increase or decrease the leaching rate (e.g., redox potential, pH, anions such as carbonate, sulfide and silicate, organic chelating agents, and adsorptive particulates).

There are limitations on the applicability of stabilization/solidification systems. For example, cement-based systems do not work when:

- the organics content is above 45% by weight,
- the wastes have less than 15% solids,
- excessive quantities of fine soil particles are present, or
- too many large particles are present.

As noted above, the most commonly used additive materials have a high pH, which can pose a problem if the stabilized wastes are subsequently land-applied or used as a soil supplement. In a series of studies to test the suitability of using treated cuttings to grow wetlands vegetation, researchers at Southeast Louisiana University discovered that cuttings stabilized in a silica matrix had a pH higher than 11. The stabilized cuttings did not support plant growth as well as unstabilized cuttings (Shaffer et al. 1998).

By adding other materials to the drilling waste, the overall volume of stabilized wastes is larger than the original volume of unstabilized waste. Depending on the amount of additive that is required to meet the applicable waste quality standards, the cost of additive may not be cost-effective.

Because of the equipment and space requirements for solidification/stabilization, this is not a practical process to use at offshore locations. It can be used at onshore locations for either onshore drilling wastes or offshore wastes that have been hauled back to shore.

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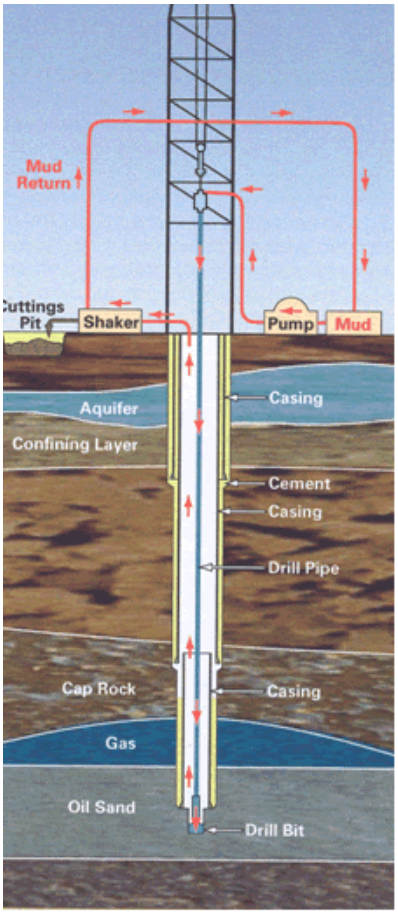
Fact Sheet - Drilling Practices to Minimize Waste

How Wells are typically drilled?

The conventional process of drilling oil and gas wells uses a rotary drill bit that is lubricated by drilling fluids or muds. As the drill bit grinds downward through the rock layers, it generates large amounts of ground-up rock known as drill cuttings. This section of the Drilling Waste Management Information System website discusses several alternative drilling practices that result in a lower volume of waste being generated.

Oil and gas wells are constructed with multiple layers of pipe known as casing. Traditional wells are not drilled from top to bottom at the same diameter but rather in a series of progressively smaller-diameter intervals. The top interval is drilled starting at the surface and has the largest diameter hole. Drill bits are available in many sizes to drill different diameter holes. The hole diameter can be 20" or larger for the uppermost sections of the well, followed by different combinations of progressively smaller diameters. Some of the common wellbore diameters are: 17.5", 14.75", 12.25", 8.5", 7.875", and 6.5".

Figure 8: Fluid circulation



After a suitable depth has been reached, the hole is lined with casing that is slightly smaller than the diameter of the hole, and cement is pumped into the space between the wall of the drilled hole and the outside of the casing. This surface casing is cemented from the surface to a depth below the lowermost drinking water zone. Next, a smaller diameter hole is drilled to a lower depth, and another casing string is installed to that depth and cemented. This process may be repeated several more times. The final number of casing strings depends on the regulatory requirements in place at that location and reflects the total depth of the well and the strength and sensitivity of the formations through which the well passes.

Historically, wells were drilled to be relatively vertical and were completed at a depth to intersect a single formation. Thus, one full well was required for each completion. Modern technology allows modifications to several aspects of this procedure, thereby allowing more oil and gas production with less drilling and less waste generation. The following sections describe how drilling can be done to intersect multiple targets from the same main well bore, how wells can be drilled using smaller diameter piping in the wells, how drilling can be done using techniques that minimize the amount of drilling fluid, and drilling fluid systems that generate less waste. The U.S. Department of Energy describes these and other environmentally friendly oil field technologies in a 1999 report, "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology" (DOE 1999).

Directional Drilling

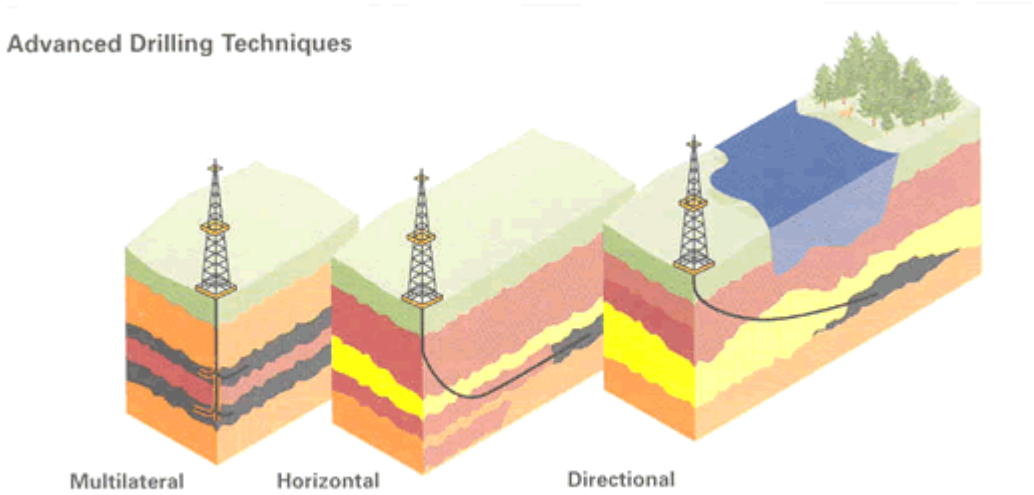
In the mid-1970s, new technologies like steerable down-hole motor assemblies and measurement-while-drilling tools became more prevalent and allowed drilling to proceed at angles off of vertical. Drillers could now more easily turn the well bore to reach targets at a horizontal offset from the location of the wellhead. This opened up many new possibilities for improving production. Three variations of directional drilling include extended-reach drilling, horizontal drilling, and multiple laterals off of a single main well bore.

Extended-Reach Drilling: In some situations, it is impractical or too expensive to drill wells from locations directly above the target formations. For example, offshore drilling is much more expensive than drilling from a shore-based facility. If the target formation is a mile from shore, it may be much more effective to directionally drill from a shore-based location. Another option involves using a single platform or drilling pad to drill multiple extended-reach wells in different directions or to different depths, thereby minimizing the number of surface well-pad facilities. An interesting example of this comes from the THUMS operations, which take place on four man-made islands in the harbour off the coast of Long Beach, California. These are disguised, camouflaged, and sound-proofed to look like a residential development. More than 1,200 wells have been directionally drilled from the islands to reach targets under the harbour. More than 60 percent of the wells drilled from the islands deviate from the vertical by 50 degrees or more. A bird's-eye view of the well bores looks like a spider's web stretching in all directions from the islands. Using extended-reach drilling allows many wells to be completed from a single location and avoids the environmental impacts of multiple surface structures.

Horizontal Drilling: Some productive formations are not thick but extend over a large lateral area. Prior to the advent of directional drilling, such formations were either uneconomical or required multiple wells to recover the resources. Modern technology allows wells to be drilled and completed in a relatively thin horizontal layer. A single horizontal well can contact more of the resource and therefore takes the place of several traditional vertical wells. Because the well bore interval from surface to producing formation is drilled only once, a horizontal well generates less waste than several vertical wells.

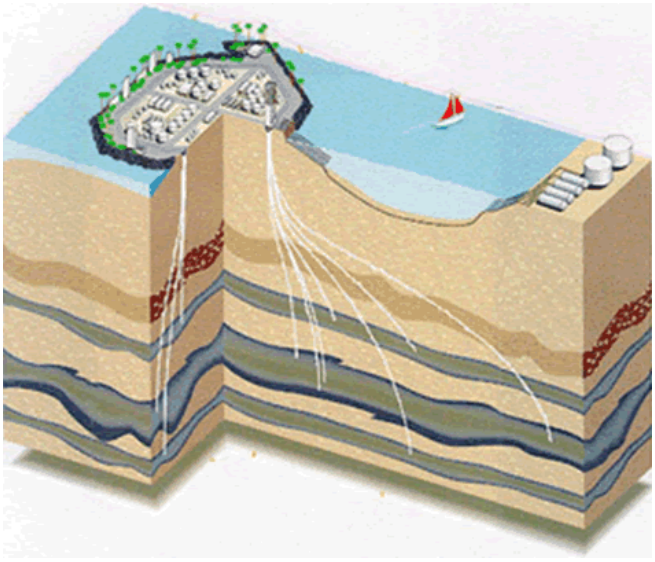
Multiple Laterals: Some formations contain multiple, small, oil-bearing zones or zones at several different depths. To recover these resources using traditional vertical wells would require many wells. With directional drilling technology, lateral well bores can be drilled off of a main vertical well bore to reach individual targets. The main well bore is drilled only once, followed by drilling of several smaller-diameter laterals. The total volume of drilling waste is lower than would be generated if several full wells were drilled.

Figure 9: Advanced drilling technique



Drilling Smaller-Diameter Holes

The amount of drill cuttings generated is directly related to the diameter of the hole that is drilled. Several technologies, often employed together, can drill smaller-diameter wells.



Closer Spacing of Successive Casing Strings: The sizes and ultimate volume of cuttings are a function of the type of drill bit and casing diameters used. In the past, only standard-sized bits and casings were available, such that each reduction in hole size was quite dramatic. The number of available bit- and casing-size options has increased dramatically in recent years. Now, adjacent casing strings can fit closer together, so the outer of the two strings need not be so far from the inner string. This reduces the volume of cuttings generated.

Figure 10: Typical cross section of directional wells

Slimhole Drilling:

According to DOE (1999), slimhole wells are defined as wells in which at least 90% of the hole has been drilled with a bit six inches or less in diameter. Although slimhole technology has been available since the 1950s, it was not commonly used because the small-diameter well bore restricted stimulation, production, and other down-hole manipulations. Modern technology has overcome these disadvantages. In addition to generating less drilling waste, slimhole rigs have a smaller footprint on a drilling pad.

Coiled Tubing Drilling: This type of drilling does not use individual sections of drill pipe that are screwed together. Instead, a continuous length of tubing is fed off of a reel and sent down the hole. The coiled tubing has a smaller diameter than traditional drill pipe so a smaller volume of cuttings is generated. In addition to reducing waste volumes, the surface footprint is smaller, the noise level is lower, and air emissions are reduced.

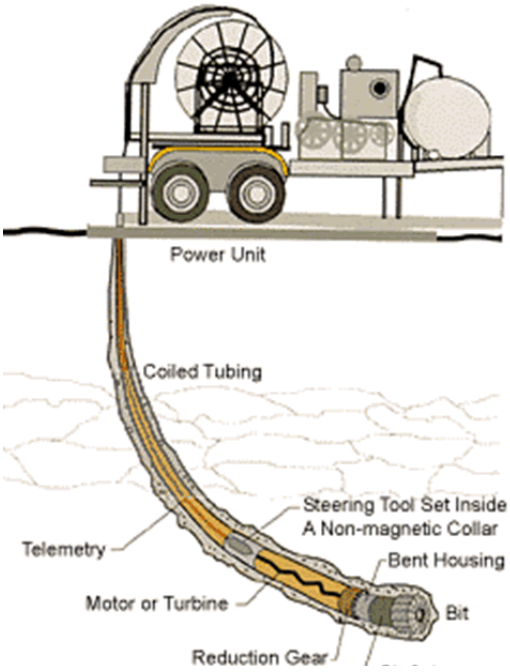


Figure 11: Coiled tubing

Mono-bore and Expandable Casing: Recent developments and success with expandable casing hold the promise of allowing a true mono-bore type well to be constructed.

Drilling Waste Management Technology Descriptions

Drilling Techniques That Use Less Drilling Fluid

Drilling fluids play an important role in traditional well drilling. However, the fluids become contaminated by their use. At the end of the drilling job, they must be disposed of or processed for recycling. For some types of wells, drilling can proceed with minimal or no drilling fluids.

Pneumatic Drilling: In selected formations, wells can be drilled using air or other gases as the fluid that circulates through the drilling system. DOE (1999) describes four different types of pneumatic drilling: air dust drilling, air mist drilling, foam drilling, and aerated mud drilling. These all rely on gas or blends of gas and mud to lift cuttings to the surface. Pneumatic drilling often does not require the large surface reserve pits common to traditional drilling. Thus, this technique can be used in environmentally sensitive areas.

Drilling Fluid Systems That Generate Less Waste

The choice of drilling fluid can affect the overall volume of used muds and cuttings that is generated. Synthetic-based muds (SBMs) drill a cleaner hole than water-based muds (WBMs), with less sloughing, and generate a lower volume of drill cuttings. SBMs are recycled to the extent possible, while used WBMs are generally discharged to the sea at offshore locations.

Other Waste Minimization Issues

Waste minimization can be looked at strictly from the perspective of solid waste volume. A more comprehensive view of "minimization" looks at the overall environmental impacts associated with a process or technology. This website primarily focuses on minimization of solid waste or wastewater streams. Readers are encouraged to consider other issues, like air emissions and energy usage, as they evaluate technology options.

There are many relatively simple processes that can be used on drilling rigs to reduce the amount of mud that is discarded or spilled. Examples include pipe wipers, mud buckets, and vacuuming of spills on the rig floor. These devices allow clean mud to be returned to the mud system and not treated as waste. Solids control equipment, like centrifuges, can be used to remove solids from the re-circulating mud stream. Although such a process does generate some solid waste, it avoids the need to discard large volumes of solids-laden muds.

This website focuses on wastes arising directly from drilling or down-hole processes. From a different perspective, the entire process of manufacturing, storing, and transporting muds to a drilling location generates wastes. Management of those wastes, used containers (e.g., drums, sacks), and wash water can benefit from waste minimization efforts too.

Applicability

The technologies and practices described are not universally applicable. Some of them only are appropriate for use in specific niches. Others can function well in many settings but may not be cost-effective; consequently, they are not selected. The total cost of drilling a well is usually hundreds of thousands to millions of dollars. These technologies are not chosen simply for their ability to reduce drilling waste volumes, because waste management costs are only one small component of the total well cost. The technologies must provide increased performance and save money for the operators. Nevertheless, as they are employed, they contribute to a waste management benefit.

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Fact Sheet - Using Muds and Additives with Lower Environmental Impacts

Introduction to Drilling Muds

Drilling fluids or muds are made up of a base fluid (water, diesel or mineral oil, or a synthetic compound), weighting agents (most frequently barium sulfate [barite] is used), bentonite clay to help remove cuttings from the well and to form a filter cake on the walls of the hole, lignosulfonates and lignites to keep the mud in a fluid state, and various additives that serve specific functions.

Figure 12: Mud returns at header box

Historically, the drilling industry has used primarily water-based muds (WBMs) because they are inexpensive. The used mud and cuttings from wells drilled with WBMs can be readily disposed of onsite at most onshore locations. WBMs and cuttings can also be discharged from platforms in many U.S. offshore waters, as long as they meet current effluent limitations guidelines (ELGs), discharge standards, and other permit limits. WBMs do not present environmental problems for organisms living in the water column or widespread problems for organisms living on the sea floor. However, for difficult drilling situations, such as wells drilled in reactive shales, deep wells, and horizontal and extended-reach wells, WBMs do not offer consistently good drilling performance. For these types of drilling situations at onshore sites, the industry relies primarily on oil-based muds (OBMs). OBMs perform well, but may be subject to more complicated disposal requirements for onshore wells. OBMs contain diesel or mineral oil as the base fluid and may be harmful to the environment when discharged to the sea. Consequently, the EPA prohibited any discharge of OBMs or their cuttings from offshore platforms.

Synthetic-Based Muds (SBMs) Alternative to Traditional Muds

In the 1990s, drilling fluid companies devised new types of muds that used non-aqueous fluids (other than oils) as their base. Examples of these base fluids included internal olefins, esters, linear alpha-olefins, poly alpha-olefins, and linear paraffins. SBMs share the desirable drilling properties of OBMs but are free of polynuclear aromatic hydrocarbons and have lower toxicity, faster biodegradability, and lower bioaccumulation potential. For these reasons, SBM cuttings are less likely than oil-based cuttings to cause adverse sea floor impacts. The EPA has identified this product substitution approach as an excellent example of pollution prevention that can be accomplished by the oil and gas industry. SBMs drill a cleaner hole than water-based muds, with less sloughing, and generate a lower volume of drill cuttings. SBMs are recycled to the extent possible, while WBMs are discharged to the sea.

New Drilling Fluid Systems

Drilling fluid companies are developing variations of fluid systems that are much more amenable to bio-treatment of the subsequent drilling wastes (Growcock et al. 2002; Getliff et al. 2000). It is likely that companies will continue to develop fluids with suitable drilling properties that contain fewer components or additives that would inhibit subsequent break down by earthworms or microbes. In some circumstances, the constituents of the muds could actually serve as a soil supplement or horticultural aid.

Other developments in drilling fluids could lead to entirely different formulations. Drilling fluids based on formate brines have been suggested as being more environmentally friendly than traditional fluids. Formate brines are created by reacting formic acid with metal hydroxides. Common examples are ceasium formate ($HCOO^-Cs^+$), potassium formate ($HCOO^-K^+$), and sodium formate ($HCOO^-Na^+$).

The primary environmental drawback to WBMs is that they require a high dilution rate to maintain desirable properties (on the order of 5 times the volume of the hole drilled) as compared to OBMs and SBMs, which require very little dilution. WBMs do not offer the same level of drilling performance and well bore stability as OBMs and SBMs. A new generation of WBMs has been developed and used effectively in the past few years. They have demonstrated improved drilling performance and significantly reduced dilution rates.

Alternate Weighting Agents

Substitution of some of the key components of drilling fluids with more environmentally friendly products could reduce mass loadings of potentially harmful substances to the environment. Barite is the most commonly used weighting agent. Other readily available weighting agents include hematite (Fe_2O_3) and calcium carbonate ($CaCO_3$). Other wells have been drilled using ilmenite ($FeTiO_3$) instead of barite as a weighting agent.

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Fact Sheet - Beneficial Reuse of Drilling Wastes

Recycling of Muds

Most water-based muds (WBMs) are disposed of when the drilling job is finished. In contrast, many oil-based muds (OBMs) and synthetic-based muds (SBMs) are recycled when possible. Sometimes the physical and chemical properties of the used muds have degraded somewhat, and the muds must be processed to rejuvenate the necessary properties. In other cases, the muds have been degraded sufficiently that they cannot economically be reused as new muds, and they must be put to a different type of reuse or final fate.

There are many relatively simple processes that can be used on drilling rigs to capture clean mud that would otherwise be discarded and return it to use. Examples include pipe wipers, mud buckets, and vacuuming of spills on the rig floor. Recovery of mud during tank cleaning may also allow the mud to be reused. Solids control equipment, like centrifuges, can be used to remove solids from the re-circulating mud stream.

Some new drilling mud formulations are designed to aid vegetative growth so that the muds can be land-applied. These could have application in horticulture or in reclamation of damaged or low-quality soils.

Reuse of Cuttings

Drill cuttings are made up of ground rock coated with a layer of drilling fluid. Most drill cuttings are managed through disposal, although some are treated and beneficially reused. Before the cuttings can be reused, it is necessary to ensure that the hydrocarbon content, moisture content, salinity, and clay content of the cuttings are suitable for the intended use of the material. Some cuttings, particularly when a saltwater-type mud was used to drill the well, may need washing to remove dissolved salts prior to beneficial use. Water used for washing can be disposed of in an injection well.

Road Spreading: One use of cuttings is to stabilize surfaces that are subject to erosion, such as roads or drilling pads. Oily cuttings serve the same function as traditional tar-and-chip road surfacing. Not all regulatory agencies allow road spreading. Where it is permitted, operators must obtain permission from the regulatory agency and the landowner before spreading cuttings. Some jurisdictions limit road spreading to dirt roads on the lease, while others may allow cuttings to be spread on public dirt roads, too. Operators should make sure that cuttings are not spread close to stream crossings or on steep slopes. Application rates should be controlled so that no free oil appears on the road surface.

Reuse of Cuttings as Construction Material: After primary separation on shale shakers, cuttings are still coated with mud and are relatively hard to reuse for construction purposes. Various further treatment steps can be employed to render the cuttings more innocuous. Some cuttings are thermally treated to remove the hydrocarbon fractions, leaving behind a relatively clean solid material. Other cuttings are screened or filtered to remove most of the attached liquid mud. If cuttings contain too much liquid, they can be stabilized by adding fly ash, cement, or some other materials to improve their ease of handling.

Treated cuttings have been used in various ways:

- fill material,
- daily cover material at landfills,
- aggregate or filler in concrete, brick, or block manufacturing.

Other possible construction applications include use in road pavements, bitumen, and asphalt or use in cement manufacture. At least one state oil and gas agency reports that cuttings can be used for plugging and abandoning wells. The economics of this approach is rarely based on the value of the finished product, but rather on the alternative cost for the other disposal options. Properly done, drilling waste can be used as a filler or base material to make other products; however, the legal liability will always stay with the company who produced the waste initially.

Restoration of Wetlands Using Cuttings: Another new application for drilling wastes involves using them as a substrate for restoring coastal wetlands. The DOE funded several projects to test the feasibility of treating cuttings and using them to help restore damaged wetlands in Louisiana. The first phase of work involved greenhouse mesocosm experiments, in which several species of wetlands plants were grown in treated cuttings, topsoil, and dredged sediments (the typical substrate used in wetlands restoration operations). The results indicated that properly treated cuttings grew wetlands vegetation as well as the dredged material. However, neither the U.S. Army Corps of Engineers nor the EPA would issue a permit to conduct a field demonstration of the approach. To date, no field demonstrations of this promising waste management approach have been tried in the United States or elsewhere, but it is likely that over the next decade the approach will be tested somewhere.

Figure 13: Greenhouse

Use of Cuttings for Fuel: Several trials have been conducted in the United Kingdom using oily cuttings as a fuel at a power plant. Cuttings were blended in at a low rate with coal, the primary fuel source. The resulting ash was much the same as the ash from burning just the coal. Generating stations should be located near the point where cuttings originate or are landed onshore from offshore operations, to minimize the need to transport cuttings.

Additional Thoughts on Recycling

In most situations, reusing or recycling wastes or by products is a desirable practice. The Drilling Waste Management Information System supports and encourages legitimate recycling and reuse, where it is practical and cost-effective. However, there are some cases in which individuals or companies may attempt to circumvent legitimate waste management regulations or laws by "sham recycling" in order to avoid costly waste management requirements (e.g., some wastes are recycled for end uses with little value solely to avoid complex and expensive hazardous waste management rules). Readers are advised to consult the regulatory agency with authority in the area where the drilling or waste management occurs to ensure that recycling is allowable under the relevant regulatory requirements.

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Fact Sheet - Onsite Burial (Pits, Landfills)

Burial is the placement of waste in man-made or natural excavations, such as pits or landfills. Burial is the most common onshore disposal technique used for disposing of drilling wastes (mud and cuttings). Generally, the solids are buried in the same pit (the reserve pit) used for collection and temporary storage of the waste mud and cuttings after the liquid is allowed to evaporate. Pit burial is a low-cost, low-tech method that does not require wastes to be transported away from the well site, and, therefore, is very attractive to many operators.

Burial may be the most misunderstood or misapplied disposal technique. Simply pushing the walls of the reserve pit over the drilled cuttings is generally not acceptable. The depth or placement of the burial cell is important. A moisture content limit should be established on the buried cuttings, and the chemical composition should be determined. Onsite pit burial may not be a good choice for wastes that contain high concentrations of oil, salt, biologically available metals, industrial chemicals, and other materials with harmful components that could migrate from the pit and contaminate usable water resources.

In some oil field areas, large landfills are operated to dispose of oil field wastes from multiple wells. Burial usually results in anaerobic conditions, which limits any further degradation when compared with wastes that are land-farmed or land-spread, where aerobic conditions predominate.

Pits

The use of earthen or lined pits is integral to drilling waste management. During most U.S. onshore drilling operations, the cuttings separated by the shale shaker are sent to a pit called the reserve pit located near the drill rig. The pit is generally open to the atmosphere, so it also accumulates storm water and wash water from the rig. The strategic location of small pits near drilling sites can also help minimize spillage of waste materials. Unless site characteristics are such that no significant threat to water resources can occur, liners are generally required. Where pits must be constructed adjacent to water bodies or on sloping terrain, engineering precautions incorporated into the design will help to ensure pit integrity. Precautions should be taken to prevent disposal of chemicals, refuse, debris, or other materials not intended for pit disposal.

Figure 14: Oilfield waste pits

At the end of the drilling job, any hydrocarbon products floating on top of the pits are recovered and any free water or other liquids are collected and disposed of, usually in an injection well. The remaining cuttings are covered in place using native soils, the surface is graded to prevent water accumulation, and the area is re-vegetated with native species to reduce the potential for erosion and promote full recovery of the area's ecosystem. Reserve pits should be closed as soon as possible following the generally accepted closure procedures in the region.

For wastes with constituent concentrations only slightly higher than those allowed for traditional pit burial, the wastes may be blended with clean, local soil to dilute and reduce the high concentrations to acceptable levels before the waste/soil mix is buried. The objective of this approach is to incorporate wastes that meet required criteria into the soil at a level below the major rooting zone for plants but above the water table (Bansal and Sugiarto 1999). Costs for such burial depend on the volume of soil required to be mixed to bring concentrations of oil and grease to within appropriate oil and grease limits (e.g., <3% by weight), pit excavation costs, and loading/hauling costs of soils and cuttings. The average drilling waste burial costs are estimated at $7 to $8 per barrel (Bansal and Sugiarto 1999).

Landfills

Landfills are used throughout the world for disposing of large volumes of municipal, industrial, and hazardous wastes. In landfills, wastes are placed in an engineered impoundment in the ground. At the end of each day or on some other cycle, the waste is covered with a layer of clean soil or some other inert cover material. Modern design standards require clay or synthetic liners, although, in some areas, unlined landfills continue to operate.

Figure 15: Commercial Oilfield waste land fill

Landfills can be used for disposing of drilling wastes and other oil field wastes. In some circumstances, these are offsite commercial operations established to receive wastes from multiple operators in an oil field (e.g., the West Texas region). In other cases, oil companies with a large amount of drilling activity in an area may construct and operate private landfills. For example, Total designed and built a controlled landfill to dispose of inert wastes at a remote site in Libya, where other management alternatives were not readily available. At this landfill, a bottom liner overlaid by a geological barrier was developed to prevent contamination of the soil. A top liner, which is drawn over the waste during non-active periods, will be installed

permanently after the landfill is closed. Two collection pits collect rainwater and subsequent leachate (Morillon et al. 2002).

Figure 16: Commercial Oilfield waste land fill

Implementation Considerations

Wastes suitable for burial are generally limited to solid or semi-solid, low-salt, low-hydrocarbon content inert materials, such as water-based drill cuttings. Costs for disposing of cuttings that have been stabilized prior to dilution and burial are estimated at $9-10 per barrel of waste (Bansal and Sugiarto 1999).

Factors to consider for burying drilling wastes include the following:

- Depth above and below pit. Areas with shallow groundwater are not appropriate; a pit location of at least five feet above any groundwater is recommended to prevent migration to the groundwater. The top of the burial cell should be below the rooting zone of any plants likely to grow in that area in the future (normally about three feet).
- Type of soil surrounding the pit. Low-permeability soils such as clays are preferable to high-permeability soils such as sands.
- For offsite commercial landfills, any protocols required by the facility accepting the waste (not all facilities have the same acceptance criteria).
- Prevention of runoff and leaching. Appropriate types and degree of controls to prevent runoff and leaching should be implemented. Natural barriers or manufactured liners placed between the waste material and the groundwater help control leaching.
- Appropriate monitoring requirements and limits.
- Time required to complete the burial.
- Chemical composition of the buried cuttings.
- Moisture content or condition of buried cuttings.

The advantages of onsite burial of drilling wastes include the following:

- Simple, low-cost technology for uncontaminated solid wastes.
- Limited surface area requirements.

Concerns include the following:

- Potential for groundwater contamination if burial is not done correctly or contaminated wastes are buried, and the resulting liability costs.
- Requirements for QA/QC, stabilization, and monitoring.

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Fact Sheet - Land Application

The objective of applying drilling wastes to the land is to allow the soil's naturally occurring microbial population to metabolize, transform, and assimilate waste constituents in place. Land application is a form of bioremediation, and is important enough to be described in its own fact sheet; other forms of bioremediation are described in a separate fact sheet.

Several terms are used to describe this waste management approach, which can be considered both treatment and disposal. In general, land farming refers to the repeated application of wastes to the soil surface, whereas land spreading and land treatment are often used interchangeably to describe the *one-time application* of wastes to the soil surface. Some practitioners do not follow the same terminology convention, and may interchange all three terms. Readers should focus on the technologies rather than on the specific names given to each process.

Optimal land application techniques balance the additions of waste against a soil's capacity to assimilate the waste constituents without destroying soil integrity, creating subsurface soil contamination problems, or causing other adverse environmental impacts.

Land Farming

The exploration and production (E&P) industry has used land farming to treat oily petroleum industry wastes for years. Land farming is the controlled and repeated application of wastes to the soil surface, using microorganisms in the soil to naturally biodegrade hydrocarbon constituents, dilute and attenuate metals, and transform and assimilate waste constituents.

Land farming can be a relatively low-cost drilling waste management approach. Some studies indicate that land farming does not adversely affect soils and may even benefit certain sandy soils by increasing their water-retaining capacity and reducing fertilizer losses. Inorganic compounds and metals are diluted in the soil, and may also be incorporated into the matrix (through chelation, exchange reactions, covalent bonding, or other processes) or may become less soluble through oxidation, precipitation, and pH effects. The attenuation of heavy metals (or the taking up of metals by plants) can depend on clay content and cation-exchange capacity.

Optimizing Land Farm Operations: The addition of water, nutrients, and other amendments (e.g., manure, straw) can increase the biological activity and aeration of the soil, thereby preventing the development of conditions that might promote leaching and mobilization of inorganic contaminants. During periods of extended dry conditions, moisture control may also be needed to minimize dust.

Periodic tillage of the mixture (to increase aeration) and nutrient additions to the waste-soil mixture can enhance aerobic biodegradation of hydrocarbons. After applying the wastes, hydrocarbon concentrations are monitored to measure progress and determine the need for enhancing the biodegradation processes. Application rates should be controlled to minimize the potential for runoff.

Pre-treating the wastes by composting and activating aerobic biodegradation by regular turning (windrows) or by forced ventilation (biopiles) can reduce the amount of acreage required for land farming (Morillon et al. 2002).

Drilling Waste Land Farm Example: In 1995, HS Resources, an oil and gas company operating in Colorado, obtained a permit for a non commercial land farm to treat and recycle the company's nonhazardous oil field wastes, including drilling muds. At the land farm, wastes mixed with soil contaminated with hydrocarbons from other facilities are spread in a layer one foot thick or less. Natural bacterial action is enhanced through occasional addition of

commercial fertilizers, monthly tilling (to add oxygen), and watering (to maintain 10-15% moisture content). Treatment is considered complete when hydrocarbon levels reach concentrations specified by regulatory agencies; not all agencies employ the same acceptability standards. Water and soil are monitored periodically to confirm that no adverse soil or groundwater impacts have occurred, and records of the source and disposition of the remediated soil are maintained. Estimated treatment costs, which include transportation, spreading, amendments, and monitoring, are about $4-5 per cubic yard. When the treated material is recycled as backfill, net costs are about $1 per cubic yard. Capital costs (not included in the treatment cost estimates) were recovered within the first eight months of operation (Cole and Mark 2000).

Implementation Considerations: Advantages of land farming include its simplicity and low capital cost, the ability to apply multiple waste loadings to the same parcel of land, and the potential to improve soil conditions. Concerns associated with land farming are its high maintenance costs (e.g., for periodic land tilling, fertilizer); potentially large land requirements; and required analysis, testing, demonstration, and monitoring. Elevated concentrations of hydrocarbons in drilling wastes can limit the application rate of a waste on a site.

Wastes containing salt must also be carefully applied to soil. Salt, unlike hydrocarbons, cannot biodegrade but may accumulate in soils, which have a limited capacity to accept salts. If salt levels become too high, the soils may be damaged and treatment of hydrocarbons can be inhibited. Salts are soluble in water and can be managed. Salt management is part of prudent operation of a land farm.

Another concern with land farming is that while lower molecular-weight petroleum compounds biodegrade efficiently, higher molecular-weight compounds biodegrade more slowly. This means that repeated applications can lead to accumulation of high molecular weight compounds. At high concentrations, these recalcitrant constituents can increase soil-water repellency, affect plant growth, reduce the ability of the soil to support a diverse community of organisms, and render the land farm no longer useable without treatment or amendment (Callahan et al. 2002). Recent studies have supported the idea that field-scale additions of earthworms with selected organic amendments may hasten the long-term recovery of conventionally treated petroleum contaminated soil. The burrowing and feeding activities of earthworms create space and allow food resources to become available to other soil organisms that would be unable to survive otherwise. The use of earthworms in Europe has improved the biological quality of soils of some large-scale land-reclamation projects.

When considering land farming as a waste management option, several items should be considered. These include site topography, site hydrology, neighbouring land use, and the physical (texture and bulk density) and chemical composition of the waste and the resulting waste-soil mixture. Wastes that contain large amounts of oil and various additives may have diverse effects on parts of the food chain. Constituents of particular concern include pH, nitrogen (total mass), major soluble ions (Ca, Mg, Na, Cl), electrical conductivity, total metals, extractable organic halogens, oil content, and hydrocarbons. Oil-based muds typically utilize an emulsified phase of 20 to 35 percent by weight $CaCl_2$ brine. This salt can be a problem in some areas, such as some parts of Canada, the mid-continent, and the Rocky Mountains. For this reason, alternative mud systems have emerged that use an environmentally preferred beneficial salt, such as calcium nitrate or potassium sulphate as the emulsified internal water phase.

Wastes that contain significant levels of biologically available heavy metals and persistent toxic compounds are not good candidates for land farming, as these substances can accumulate in the soil to a level that renders the land unfit for further use (E&P Forum 1993). (Site monitoring can help ensure such accumulation does not occur.) Land farms may require permits or other approvals from regulatory agencies, and, depending on soil conditions, some land farms may require liners and/or groundwater monitoring wells.

Drilling Waste Management Technology Descriptions

Land Treatment

In land treatment (also known as land spreading), the processes are similar to those in land farming, where natural soil processes are used to biodegrade the organic constituents in the waste. However, in land treatment, a *one-time application* of the waste is made to a parcel of land. The objective is to dispose of the waste in a manner that preserves the subsoil's chemical, biological, and physical properties by limiting the accumulation of contaminants and protecting the quality of surface and groundwater. The land spreading area is determined on the basis of a calculated loading rate that considers the absolute salt concentration, hydrocarbon concentration, metals concentration, and pH level after mixing with the soil. The drilling waste is spread on the land and incorporated into the upper soil zone (typically upper 6-8 inches of soil) to enhance hydrocarbon volatization and biodegradation. The land is managed so that the soil system can degrade, transport, and assimilate the waste constituents. Each land treatment site is generally used only once.

Optimizing Land Treatment Operations: Addition of water, nutrients, and other amendments (e.g., manure, straw) can increase the biological activity and aeration of the soil and prevent the development of conditions that might promote leaching and mobilization of inorganic contaminants. During periods of extended dry conditions, moisture control may also be needed to minimize dust. Periodic tillage of the mixture (to increase aeration) and nutrient additions to the waste soil mixture can enhance aerobic biodegradation of hydrocarbons, although in practice not all land treatment projects include repeated tilling. After applying the wastes, hydrocarbon concentrations may be monitored to measure progress and determine the need for enhancing the biodegradation processes.

Implementation Considerations: Because land spreading sites receive only a single application of waste, the potential for accumulation of waste components in the soil is reduced (as compared with land farming, where waste is applied repeatedly). Although liners and monitoring of leachate are typically not required at land treatment sites, site topography, hydrology, and the physical and chemical composition of the waste and resultant waste-soil mixture should be assessed, with waste application rates controlled to minimize the possibility of runoff.

Experiments conducted in France showed that after spreading oil-based mud cuttings on farmland, followed by ploughing, tilling, and fertilizing, approximately 10% of the initial quantity of the oil remained in the soil. Phytotoxic effects on seed germination and sprouting were not observed, but corn and wheat crop yields decreased by 10% (Smith et al. 1999). Yields of other crops were not affected. The percentage of hydrocarbon reduction and crop yield performance will vary from site to site depending on many factors (e.g., length of time after application, type of hydrocarbon, soil chemistry, temperature).

Land spreading costs are typically $2.50 to $3.00 per barrel of water-based drilling fluids not contaminated with oil, and they could be higher for oily wastes containing salts (Bansal and Sugiarto 1999). Costs also depend on sampling and analytical requirements.

Advantages of land spreading are the low treatment cost and the possibility that the approach could improve soil characteristics. Land spreading is most effectively used for drilling wastes that have low levels of hydrocarbons and salts. Potential concerns include the need for large land areas; the relatively slow degradation process (the rate of biodegradation is controlled by the inherent biodegradation properties of the waste constituents, soil temperature, soil-water content, and contact between the microorganisms and the wastes); and the need for analyses, tests, and demonstrations. Also, high concentrations of soluble salts or metals can limit the use of land spreading.

When evaluating land spreading as a drilling waste management option, several items should be considered. These include area-wide topographical and geological features; current and likely future activities around the disposal site; hydrogeologic data (location, size, and direction

of flow for existing surface water bodies and fresh or useable aquifers); natural or existing drainage patterns; nearby environmentally sensitive features such as wetlands, urban areas, historical or archaeological sites, and protected habitats; the presence of endangered species; and potential air quality impacts. In addition, historical rainfall distribution data should be reviewed to establish moisture requirements for land spreading and predict net evaporation rates. Devices needed to control water flow into, onto, or from facility systems should be identified. Wastes should be characterized during the evaluation; drilling wastes with high levels of hydrocarbons and salts may not be appropriate for land spreading.

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Fact Sheet - Bioremediation

Bioremediation (also known as biological treatment or bio-treatment) uses microorganisms (bacteria and fungi) to biologically degrade hydrocarbon-contaminated waste into nontoxic residues. The objective of bio-treatment is to accelerate the natural decomposition process by controlling oxygen, temperature, moisture, and nutrient parameters. Land application is a form of bioremediation that is described in greater detail in a separate fact sheet. This fact sheet focuses on forms of bioremediation technology that take place in more intensively managed programs, such as composting, vermiculture, and bioreactors. McMillen et al. (2004) summarizes over ten years of experience in bio-treating exploration and production wastes and offers ten lessons learned.

Bioremediation decisions can be facilitated through the use of risk-based decision making (RBDM), a process that uses risk considerations to develop cleanup levels that are environmentally acceptable for the given characteristics and anticipated land use of a specific site. The application of RBDM for cleaning up contaminated exploration and production sites is detailed in a book published by the U.S. Department of Energy and the Petroleum Environmental Research Forum, titled, *Risk-Based Decision-Making for Assessing Petroleum Impacts at Exploration and Production Sites* (McMillen et al. 2001).

Some advantages of biological treatment are: it is relatively environmentally benign; it generates few emissions; wastes are converted into products; and it requires minimal, if any, transportation. Sometimes, bioremediation is used as an interim treatment or disposal step, which reduces the overall level of hydrocarbon contamination prior to final disposal. Bioremediation can create a drier, more stable material for land filling, thereby reducing the potential to generate leachate. Depending on the composition of the hydrocarbon components, the bioremediation environment, and the type of treatment utilized, bioremediation may be a fairly slow process and require months or years to reach the desired result.

Composting

In composting, wastes are mixed with bulking agents such as wood chips, straw, rice hulls, or husks to increase porosity and aeration potential for biological degradation. The bulking agents provide adequate porosity to allow aeration even when moisture levels are high. To increase the water-holding capacity of the waste-media mixture, and to increase trace nutrients, manure or agricultural wastes may be added. Adding nitrogen- and phosphorus-based fertilizers and trace minerals can also enhance microbial activity and reduce the time required to achieve the desired level of biodegradation.

Composting is similar to land treatment, but it can be more efficient. Also, with composting systems, treated waste is contained within the composting facility where its properties can be readily monitored. With composting, mixtures of the waste, soil (to provide indigenous bacteria), and other additives may be placed in piles to be tilled for aeration, or placed in containers or on platforms to allow air to be forced through the composting mixture. To optimize moisture conditions for biodegradation, the compost mixture is maintained at 40 to 60% water by weight. Elevated temperatures (30 to 70 degrees C) in compost mixtures increase microbial metabolism. However, if temperatures exceed 70 degrees, cell death can occur. Tilling the soil pile or forced aeration can help control temperature and oxygen levels. Composting in closed containers can control volatile emissions. Composted wastes that meet health-based criteria can be used to condition soil, cover landfills, and supply clean fill. McMillen and Gray (1994) reported estimated costs for windrow composting of exploration and production wastes to range from $40 to $70 per cubic meter.

Figure 17: Composting in windrows

Figure 18: Waste compost treatment at an Operators site

Bioreactors

Bioreactors work according to the same aerobic biological reactions that occur in land treatment and composting, but the reactions occur in an open or closed vessel or impoundment. This environment accelerates the rate of biodegradation by allowing better control of the temperature and other conditions that affect the biodegradation rate. Bioreactor processes are typically operated as a batch or semi-continuous process. In a bioreactor, nutrients are added to a slurry of water and waste, and air sparging or intensive mechanical mixing of the reactor contents provides oxygen. This mechanical mixing results in significant contact between microorganisms and the waste components being degraded. To accelerate system start-up, introduction of microbes capable of degrading the organic constituents of the waste may be useful, although some companies have not had favourable experience with designer bugs. Many of the additives used for bioreactors are common agricultural products and plant or animal wastes.

After the desired treatment level has been reached, and depending on the constituents, liquids may be reused, transported to wastewater treatment facilities, injected, or discharged. Solids

may be buried, applied to soils, used as fill, or treated further to stabilize components such as metals.

In tank-based bioreactors, operating conditions (temperature, nutrient concentration, pH, oxygen transport and mixing) can be monitored and controlled easily. Optimized biological processes ensure the best rate of biodegradation and allow for reduced space requirements relative to land-based biological treatment processes. However, capital and operation and maintenance costs for bioreactors are high relative to other forms of biological treatment. McMillen and Gray (1994) reported estimated costs for bioreactor treatment of oily cuttings wastes of approximately $500 per cubic meter.

Vermiculture

Vermiculture is the process of using worms to decompose organic waste into a material capable of supplying necessary nutrients to help sustain plant growth. For several years, worms have been used to convert organic waste into organic fertilizer. Recently, the process has been tested and found successful in treating certain synthetic-based drilling wastes (Norman et al. 2002).

Figure 19: Vermiculture showing worms

Researchers in New Zealand have conducted experiments to demonstrate that worms can facilitate the rapid degradation of hydrocarbon-based drilling fluids and subsequently process the minerals in the drill cuttings. Because worm cast (manure) has important fertilizer properties, the process may provide an alternative drill cutting disposal method. In the experiments, drill cuttings were mixed with sawdust to facilitate transport, shipped to the vermiculture site, blended with undigested grass, mixed with water, and applied to worm beds. The feeding consists of applying the mixture as feedstock to windrows, which are covered to exclude light from the worm bed and protect it from becoming waterlogged. Controlled irrigation systems correct the moisture content during periods of low rainfall. The feedstock was applied to the windrows, generally once per week, at an average depth of 15 to 30 mm. The worms "work" the top of each windrow, consuming the applied material over a 5- to 7-day period. The resulting worm cast organic fertilizer is harvested and packaged for distribution and use as a beneficial fertilizer and soil conditioner.

Figure 20: Vermiculture operations in windrows.

The experiments showed decreases in hydrocarbon concentration from 4,600 mg/kg to below 100 mg/kg in less than 28 days, with less than 200 mg/kg remaining after 10 days. The specific biological mechanism responsible for these decreases is not known. Hypotheses include microbial degradation within the worm beds, favorable aerobic conditions generated by the burrowing and mixing actions of the worms, and metabolic consumption of the hydrocarbons by the worms.

The results also indicated the complete degradation of the cuttings (originally 5-10 mm in diameter) and no detectable mortality among the worms. The occurrence of increased heavy metal concentrations and indications of bioaccumulation in the worm cast at higher application and feeding rates would require further study or the use of alternative weighting materials (Getliff et al. 2002). The apparent optimal portion of cuttings in the feedstock is 30 to 50%. An important factor for success is the use of drilling fluids designed for bioremediation and vermiculture technology. Linear, paraffin-type base fluids, combined with nitrate or acetate brine phases, enable the worms to add value to the cuttings that are already relatively clean due to the specific design of the fluids (Getliff et al. 2002).

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Fact Sheet - Discharge to Ocean

Past Practices

In early offshore oil and gas development, drilling wastes were generally discharged from the platforms directly to the ocean. Until several decades ago, the oceans were perceived to be limitless dumping grounds. During the 1970s and 1980s, however, evidence mounted that some types of drilling waste discharges could have undesirable effects on local ecology, particularly in shallow water. When water-based muds (WBMs) were used, only limited environmental harm was likely to occur, but when operators employed oil-based muds (OBMs) on deeper sections of wells, the resulting cuttings piles created impaired zones beneath and adjacent to the platforms. At some North Sea locations, large piles of oil-based cuttings remain on the sea floor near the platforms. Piles of oil-based cuttings can affect the local ecosystem in three ways: by smothering organisms, by direct toxic effect of the drilling waste, and by anoxic conditions caused by microbial degradation of the organic components in the waste. Current regulatory controls minimize the impacts of permitted discharges of cuttings.

Stricter Regulation of Drilling Waste Discharges

In the late 1970s, the U.S. Environmental Protection Agency (EPA) began placing stronger restrictions on ocean discharges of drilling muds and cuttings through National Pollutant Discharge Elimination System (NPDES) permits. Among the early restrictions were prohibitions on the discharge of OBMs and cuttings. In 1993, the EPA adopted enhanced national discharge standards for the offshore oil and gas industry. These established additional requirements for discharging WBMs and cuttings from wells drilled at least 3 miles from shore but prohibited discharges within 3 miles of shore.

During the mid-1990s, mud companies developed and promoted synthetic-based muds (SBMs) that offered strong drilling performance like OBMs but were much closer to WBMs in environmental impact. Unfortunately, EPA's 1993 offshore discharge regulations did not consider SBMs, so there was considerable uncertainty about whether offshore operators could use the SBMs and discharge the resulting cuttings. The EPA, DOE, the Minerals Management Service, and numerous companies and industry associations worked together following an innovative expedited rulemaking process to finalize new effluent limitations guidelines (ELGs) for SBMs in 2001. Those rules allow for discharge of SBM cuttings, subject to various restrictions but prohibit the discharge of SBMs themselves. A summary of the 1993 and 2001 discharge requirements are shown in the box below.

Summary of U.S. Offshore Requirements for Drilling Wastes

Baseline Requirements

- No discharge of free oil (using a static sheen test) or diesel oil
- Acute toxicity must have a 96-hour LC50 > 30,000ppm (using EPA's mysid shrimp toxicity text)
- Metals concentrations in the barite added to mud must not exceed:
  - 1 mg/kg for mercury
  - 3 mg/kg for cadmium
- No discharge of drilling wastes allowed within 3 miles of shore (except for Alaskan facilities in the offshore subcategory)

Additional Requirements for Synthetic-Based Muds (SBMs)

- SBMs themselves may not be discharged
- Cuttings coated with up to 6.9% SBMs may be discharged
  - Ester SBMs can have up to 9.4% SBM on cuttings
- Polynuclear aromatic hydrocarbon (PAH):
  - Ratio of PAH mass to mass of base fluid may not exceed 1 x 10^{-5}
- Bio-degration rate of chosen fluid shall be no slower than that for internal olefin
  - Base fluids are tested using the marine anaerobic closed bottle test
- Base fluid sediment toxicity shall be no more toxic than that for internal olefin base fluid
  - Base fluid stocks are tested by a 10-day acute solid-phase test using amphipods (*Leptocheirus plumulosus*)
  - Discharged cuttings are tested by a 4-day acute solid-phase test using amphipods (*Leptocheirus plumulosus*)
- No discharge of formation oil
  - Whole muds are tested onshore by GC/MS analysis
  - Discharged cuttings are tested for crude oil contamination by fluorescence method
- Conduct seabed survey or participate in industry-wide seabed survey

Unlike the EPA's decision to allow discharge of SBM cuttings in the Gulf of Mexico, governments in the North Sea area decided to phase out discharges of SBMs or cuttings. Other oil-producing countries around the world have followed various strategies for regulating discharge of SBMs and cuttings. Based on the scientific evidence, the discharge of the very low quantities of SBMs that adhere to cuttings meeting all of the required regulatory criteria appear to have minimal and brief impact on the ocean environment.

Treatment Processes Prior to Discharge

After coming to the platform, drilling wastes are placed on a series of vibrating screens called shale shakers. Each successive shale shaker uses finer mesh screen, so the collected particles are smaller in size. The liquid mud passes through the screens and is sent back to mud pits on the platform to be reused. If the recycled mud contains fine particles that would interfere with drilling performance, the muds are treated using mud cleaners or centrifuges to remove very fine particles. At the end of a drilling job or at the end of a particular interval that uses a specialized mud, the bulk mud will either be returned to shore for recycling or discharged to the sea.

The solid cuttings coated with a film of mud remain on top of the shale shakers and are collected at the opposite end of the shakers. If the cuttings are able to meet the discharge standards at this point, they are generally discharged. If they are unable to meet the discharge standards (particularly relevant when SBMs are being used), the cuttings must be treated further by vertical or horizontal cuttings dryers, squeeze presses, or centrifuges. The cuttings dryers recover additional mud and produce dry, powdery cuttings.

Economic Considerations

Generally, the cost of treating and discharging drilling wastes is lower than the cost of hauling them back to shore or applying other management options. The cost of transporting wastes is eliminated when wastes are discharged. Where offshore discharge is an option approved by the regulatory agency, most operators choose that option. There may be situations in which a company elects not to discharge for public relations reasons or because of concerns over long-term liability.

Minton and McGlaughlin (2003) provide drilling waste costs as a fraction of the cost spent on drilling fluid. North Sea costs have the highest reported fraction (>0.5) among 13 regions, while the U.S. Gulf of Mexico fraction is reported as being about 0.12. This reflects the fact that many more offshore operations are discharging drilling wastes in the Gulf of Mexico than in the North Sea. North Sea operators must select other, more expensive waste management options.

References

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Fact Sheet - Commercial Disposal Facilities

Although drilling wastes from many onshore wells are managed at the well site, some wastes cannot be managed onsite. Likewise, some types of offshore drilling wastes cannot be discharged, so they are either injected underground at the platform (not yet common in the United States) or are hauled back to shore for disposal.

According to an American Petroleum Institute waste survey, the exploration and production segment of the U.S. oil and gas industry generated more than 360 million barrels (bbl) of drilling wastes in 1985. The report estimates that 28% of drilling wastes are sent to offsite commercial facilities for disposal (Wakim 1987). A similar American Petroleum Institute study conducted ten years later found that the volume of drilling waste had declined substantially to about 150 million bbl.

Why Use a Commercial Facility?

Oil and gas companies use commercial disposal facilities for various reasons. The primary reason is that the regulatory agency with jurisdiction may not allow onsite disposal for the type of drilling waste or the specific location. Examples of inappropriate wastes for onsite disposal may include saltwater muds or very oily cuttings. Examples of locations that are not appropriate for onsite burial or land application include areas with high seasonal water tables, marshy environments, or tundra.

A second reason for sending waste to commercial facilities is that it may be more cost-effective. If an operator has a relatively small volume of waste, it may make sense to send it offsite rather than have the responsibility for constructing, operating, and closing an onsite facility. Some operators may not want the responsibility of managing their waste and prefer to send the waste to a third party for management. Although this practice appears to shift the burden of responsibility and liability to the third party, the company that originally generates the waste maintains liability indefinitely under the U.S. Superfund law. If the disposal company improperly manages the waste, the government may come back to all companies that generated the wastes disposed of at the commercial facility to share in the cost of remediation. It is important to review the business practices and compliance history of an offsite commercial disposal company to minimize the risk of future liability.

Where Are Commercial Disposal Facilities Located?

In 1997, Argonne National Laboratory conducted interviews with oil and gas officials in 31 oil- and gas-producing states to learn how oil field wastes are disposed of in their states and to identify commercial offsite disposal companies (Veil 1997). Argonne then surveyed the identified disposal companies to learn what types of wastes they disposed of, what disposal methods they used, and how much they charged their customers. At that time, there were two major offsite disposal trends. Numerous commercial disposal companies that handle exclusively oil field wastes are located in nine oil- and gas-producing states. Twenty-two other oil- and gas-producing states contain few or no disposal companies dedicated to oil and gas industry waste. The only offsite commercial disposal companies available handle general industrial wastes or are sanitary landfills. In those states, operators needing to dispose of oil field wastes offsite must send them to a local landfill or out of state.

The Argonne report mentioned above contains lengthy tables that list the state, disposal company name, disposal method, disposal costs, and other comments. Table 8 provides information for disposal of oil-based muds and cuttings, and Table 10 provides information for water-based muds and cuttings.

How Do the Disposal Companies Dispose of the Wastes?

The commercial disposal companies use many different approaches for disposing of the wastes they receive (Veil 1997). For areas away from the Gulf coast, land farming operations have a significant share of the commercial disposal market. Landfills and pits represent another important disposal option for solid and oily wastes. Two New Mexico facilities evaporate the liquid fraction of the waste and then send the solids to landfills. Several other disposal facilities treat the wastes before disposing of or reusing them. A Texas facility first chemically stabilizes the waste and then landfills it. Five California facilities biologically or chemically treat waste and then reuse the residues. Several facilities use thermal treatment or incineration followed by reuse or disposal of the residues. One California commercial facility evaporates liquid wastes in a surface impoundment. Several companies in both east and west Texas operate salt caverns for commercial disposal.

Commercial facilities often use land farming or disposal pits for disposing of water-based drilling wastes. Two New Mexico companies evaporate the liquids and landfill the solids. Three Pennsylvania companies treat water-based drilling wastes and discharge them to surface waters under an NPDES permit, while a fourth Pennsylvania company treats the wastes, then discharges them to a local sanitary sewer that leads to a municipal wastewater treatment plant. A Wyoming company operates a sophisticated industrial wastewater treatment plant that either injects the treated waste or discharges it to the sanitary sewer. One California company treats the wastes and reuses the solids as landfill cover.

The largest market for offsite commercial disposal in the United States occurs when Gulf of Mexico offshore wastes are hauled back to shore. For most of the past decade, one disposal company has dominated the market. This company established a network of marine transfer facilities along the coast of Louisiana and Texas, at which operators can unload drilling wastes from work boats to barges. The barges are towed through the intracoastal waterway to Port Arthur, Texas, where the wastes are loaded into tank trucks. The trucks are driven 20 miles inland to a site where the wastes are screened and then injected underground. The site has unique geological conditions that allow huge volumes of slurried wastes to be pumped into a series of injection wells at very low pressure. According to Marinello et al. (2001), as of 2001, more than 22 million bbl of slurried waste had been injected using this mechanism, including more than 80% of the Gulf of Mexico offshore drilling waste brought back to shore and more than 90% of the naturally occurring radioactive material (NORM) from U.S. oil fields.

In the past few years, this disposal company has received some direct competition from another company that also operates a series of transfer stations along the coast. The newer company disposes of the wastes in a salt cavern located near the coast in east Texas. Other companies are in the process of permitting additional disposal caverns along the coast.

Costs

The cost of offsite commercial disposal varies, depending on the disposal method used, the state in which the disposal company is located, and the degree of competition in the area. In 1997, disposal costs reported by offsite commercial disposal facilities for oil-based drilling wastes ranged from $0 to $57/bbl, $6.50 to $50/yd, and $12 to $150/ton. Disposal costs for water-based drilling wastes ranged from $0.20 to $14.70/bbl, $5 to $37.50/yd, and $15 to $55/ton (Veil 1997).

In a separate 1998 study, in which offshore operators rather than disposal companies were interviewed, the reported disposal costs were somewhat different (Veil 1998). Several companies reported onshore disposal costs, which ranged from $7.50/bbl to $350/bbl. It is highly probable that the operator costs included the cost of additional waste handling equipment, transportation, and other items while vendors quoted their disposal fees. Therefore, these two sets of cost are not readily comparable.

Another important consideration is the transportation cost. Large volumes and weights of drilling wastes are generated at each well that is drilled. For onshore wells, disposal facilities must generally be located within a 50- to 75-mile radius of the wells in order for transportation costs to be manageable.

The company that has received most of the Gulf of Mexico offshore wastes charges $7.50/bbl for disposing of water-based cuttings and from $8.50/bbl to $11/bbl for disposal of oil-based muds and cuttings. If wastes are delivered to the transfer stations, there is an additional offloading fee of $3/bbl to $3.50/bbl. Typically the operators' drilling waste containers must be washed out, and the resulting washwater must be disposed of, too. This step adds several dollars per barrel to the total cost. There are new bulk waste transport technologies emerging that may significantly reduce the complexity and costs associated with transporting drilling wastes (e.g., cuttings pumps and pneumatic conveyance).

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Fact Sheet - Slurry Injection of Drilling Wastes

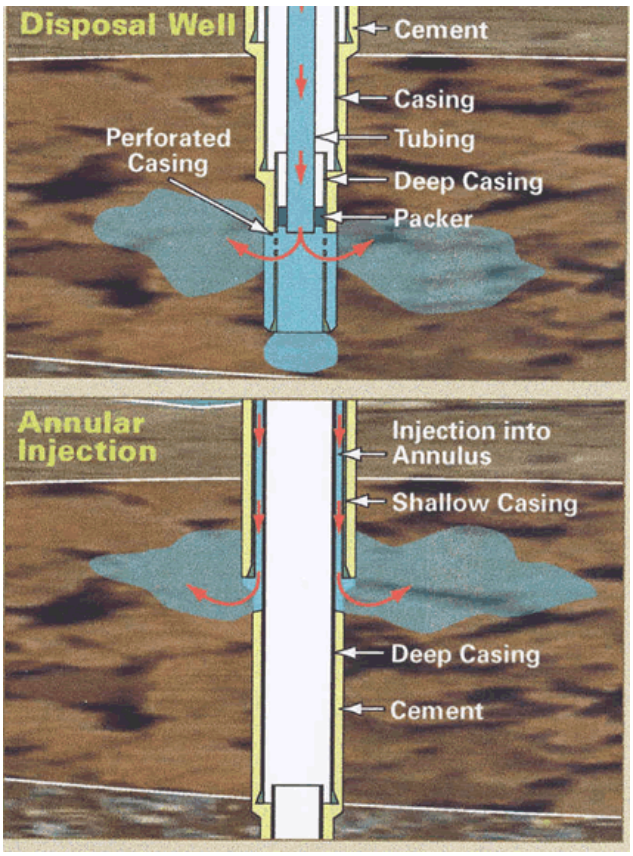
Underground Injection of Drilling Wastes

Several different approaches are used for injecting drilling wastes into underground formations for permanent disposal. Salt caverns are described in a separate fact sheet. This fact sheet focuses on slurry injection technology, which involves grinding or processing solids into small particles, mixing them with water or some other liquid to make a slurry, and injecting the slurry into an underground formation at pressures high enough to fracture the rock. The process referred to here as *slurry injection* has been given other designations by different authors, including *slurry fracture injection* (this descriptive term is copyrighted by a company that provides slurry injection services), *fracture slurry injection*, *drilled cuttings injection*, *cuttings reinjection*, and *grind and inject*.

Types of Slurry Injection

The two common forms of slurry injection are *annular injection* and *injection into a disposal well*. Annular injection introduces the waste slurry through the space between two casing strings (known as the annulus). At the lower end of the outermost casing string, the slurry enters the formation. The disposal well alternative involves injection to either a section of the drilled hole that is below all casing strings, or to a section of the casing that has been perforated with a series of holes at the depth of an injection formation.

Figure 21; Two slurry injection types



Many annular injection jobs are designed to receive wastes from just one well. On multi-well platforms or onshore well pads, the first well drilled may receive wastes from the second well. For each successive well, the drilling wastes are injected into previously drilled wells. In this mode, no single injection well is used for more than a few weeks or months. Other injection programs, particularly those with a dedicated disposal well, may inject into the same well for months or years.

A related process involves injection into formations at pressures lower than the formation's fracture pressure (*sub-fracture injection*). In certain geological situations, formations may be able to accept waste slurries at an injection pressure below the pressure required to fracture the formation. Wastes are ground, slurried, and injected, but the injection pressures are considerably lower than in the case of slurry injection. The most notable example of this process occurs in east Texas, where the rock overlying a salt dome has become naturally fractured, allowing waste slurries to be injected at very low surface injection pressures or even under a vacuum. A commercial waste disposal company has established a series of sub-fracture injection wells at several locations in east Texas. These wells have served as the disposal points for a large percentage of the drilling waste that is hauled back from offshore platforms in the Gulf of Mexico for onshore disposal.

How Is Slurry Injection Conducted?

As a first step, the solid or semi-solid drilling waste material is made into a slurry that can be injected. The waste material is collected and screened to remove large particles that might cause plugging of pumps or well perforations. Liquid is added to the solids, and the slurry (or the oversize material) may be ground or otherwise processed to reduce particle size. Prior to injection, various additives may be blended into the slurry to improve the viscosity or other physical properties.

Figure 22: Long term slurry injection approach

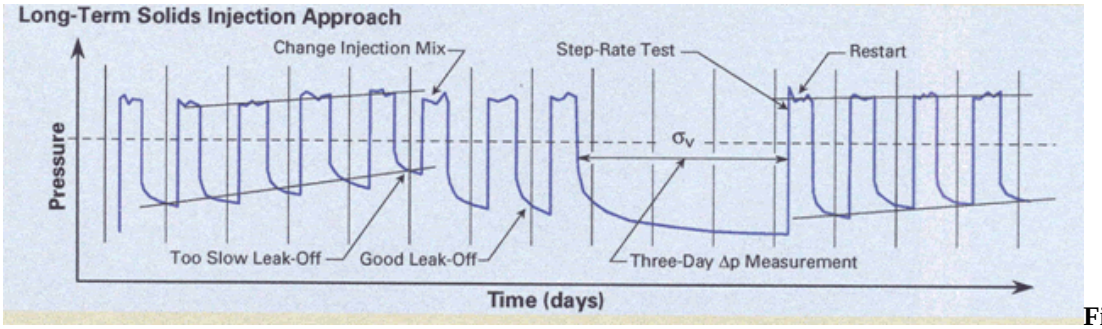
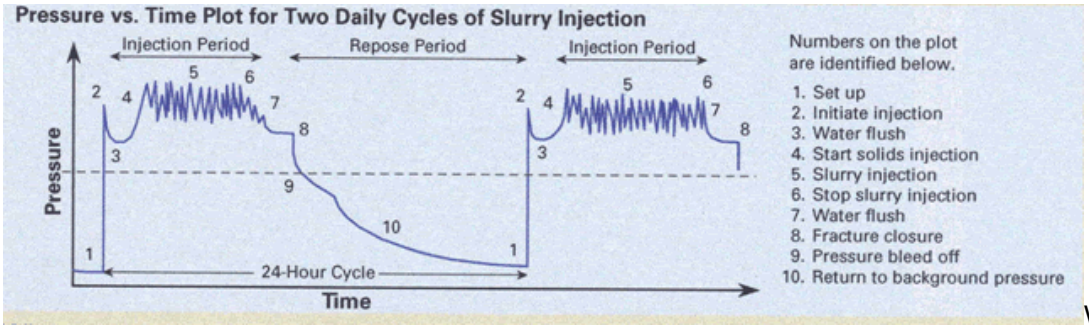


Figure 23: Pressure vs. time plot



When the slurry is ready for injection, the underground formation is prepared to receive the slurry. First, clear water is rapidly injected to pressurize the system and initiate fracturing of the formation. When the water is flowing freely at the fracture pressure, the slurry is introduced into the well. Slurry injection continues until an entire batch of slurried material has been injected. At the end of this batch, additional water is injected to flush solids from the well bore, and then pumping is

discontinued. The pressure in the formation will gradually decline as the liquid portion of the slurry bleeds off over the next few hours, and the solids are trapped in place in the formation. Slurry injection can be conducted as a single continuous process or as a series of smaller-volume intermittent cycles. On some offshore platforms, where drilling occurs continually and storage space is inadequate to operate in a daily batch manner, injection must occur continuously as new wells are drilled. Most other injection jobs are designed to inject intermittently. They inject for several hours each day, allow the formation to rest overnight, and then repeat the cycle on the following day or a few days later.

Regulatory Requirements

Slurry injection activities at onshore locations are generally subject to the requirements of the Underground Injection Control (UIC) program. The UIC program is administered by the U.S. Environmental Protection Agency but can also be delegated to state agencies (see the Regulatory section of this website for the specific EPA and state agency requirements for the UIC program). At offshore locations, the UIC program does not apply because underground sources of drinking water are not present. The Minerals Management Service issues guidelines for injection and approves slurry injection on a case-by-case basis.

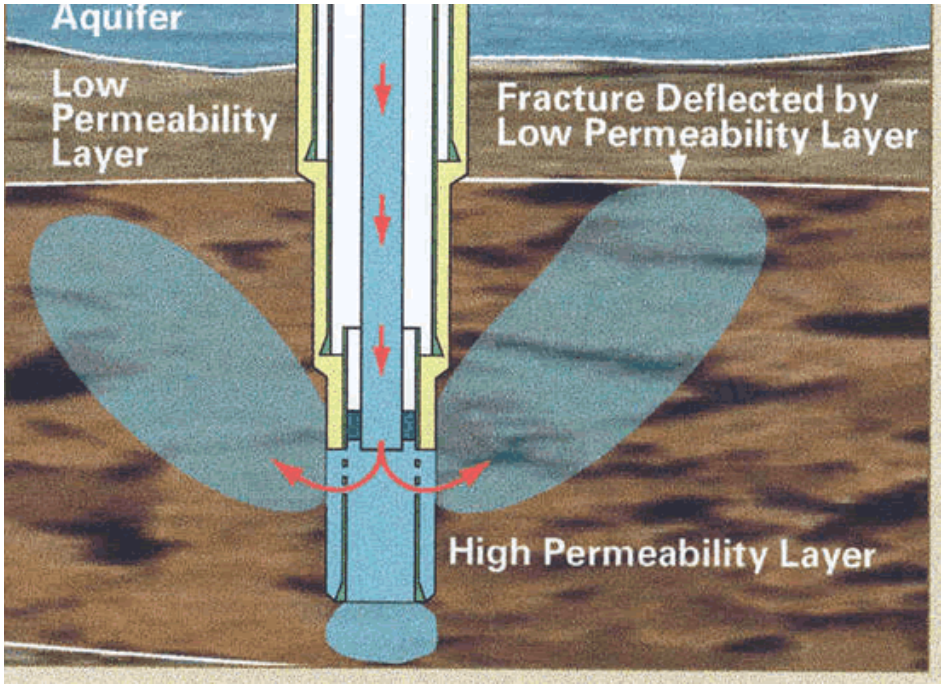
Geologic Conditions That Favour Slurry Injection

Different types of rocks have different permeability characteristics. Although rocks appear solid, they are made up of many grains or particles that are bound together by chemical and physical forces. Under the high pressure found at depths of several thousand feet, water and other fluids are able to move through the pores between particles. Some types of rock, such as clays and shale, consist of very small grains, and the pore spaces between the grains are so tiny that fluids do not move through them very readily. In contrast, sandstone is made up of cemented sand grains, and the relatively large pore spaces allow fluids to move through them much more easily.

Slurry injection relies on fracturing, and the permeability of the formation receiving the injected slurry is a key parameter in determining how readily the rock fractures, as well as the size and configuration of the fracture. When the slurry is no longer able to move through the pore spaces, and the injection pressure continues to be applied, the rocks will crack or fracture. Continuous injection typically creates a large fracture consisting of a vertical plane that moves outward and upward from the point of injection. Intermittent injection generates a series of smaller vertical planes that form a zone of fractures around the injection point. Fractures that extend too far vertically or horizontally from the point of injection can intersect other well bores, natural fractures or faults, or drinking water aquifers. This condition is undesirable and should be avoided by careful design, monitoring, and surveillance.

Most annular injection jobs inject into shale or other low-permeability formations, and most dedicated injection wells inject into high-permeability sand layers. Regardless of the type of rock selected for the injection formation, preferred sites will be overlain by formations having the opposite permeability characteristics (high vs. low). When available, locations with alternating sequences of sand and shale are good candidates to contain fracture growth. Injection occurs into one of the lower layers, and the overlying low-permeability layers serve as fracture containment barriers, while the high-permeability layers serve as zones where liquids can rapidly leak off.

Figure 24: Shape of injection plume.



Database of Slurry Injection Jobs

Argonne National Laboratory developed a database with information on 334 injection jobs from around the world (part of Veil and Dusseault 2003). The three leading areas representing slurry injection in the database are Alaska (129 records), Gulf of Mexico (66 records), and the North Sea (35 records). Most injection jobs included in the database feature annular injection (296, or more than 88%), while the remainder (36 or 11%) used dedicated injection wells. These figures reflect the large number of annular injection jobs reported for Alaska.

Most injection jobs were conducted at depths shallower than 5,000 feet; many occurred in the interval between 2,501 and 5,000 feet. The shallowest injection depth reported was 1,246 to 1,276 feet in Indonesia, and the deepest was 15,300 feet at an onshore well in Louisiana.

Figure 25: Example of volume of slurry injected.

Total Reported Slurry Volume (bbl)	*Number of Jobs*
<10,000	87
10,000 - 50,000	206
50,001 - 100,000	9
100,001 - 500,000	13
500,001 - 1,000,000	5
>1,000,000	12
Total	332

The reported injection rates range from 0.3 bbl/minute to 44 bbl/minute. The reported injection pressures range from 50 pounds per square inch (psi) to 5,431 psi.

Most wells in the database were used to inject drill cuttings. Many were also used to inject other types of oil field wastes, including produced sands, tank bottoms, oily wastewater, pit contents, and scale and sludge that contain naturally occurring radioactive material (NORM).

The table notes the number of records that reported injectate volumes within specified ranges. The data show that more than 83% of the injection jobs in the database involved less than 50,000 bbl of slurry. The largest job reported in the database involved more than 43 million bbl of slurry injected in several wells associated with a dedicated grind-and-inject project at Prudhoe Bay on the North Slope of Alaska.

Observed Problems

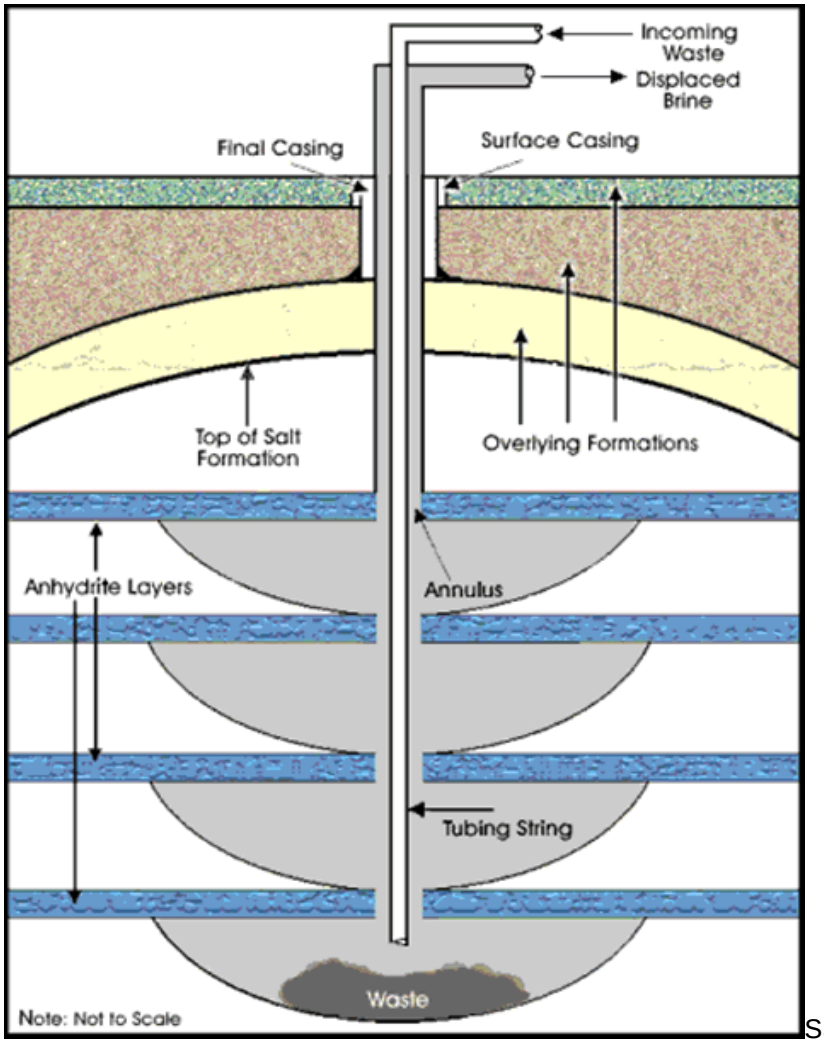
Problems were reported in fewer than 10% of the database records. The most common problem was operations-related (e.g., plugging of the casing or piping because solids had settled out during or following injection; excessive erosion of casing, tubing, and other system components caused by pumping solids-laden slurry at high pressure). Environmental problems associated with slurry injection are rare but are of much greater concern. Few documented cases of environmental damage caused by slurry injection exist. Unanticipated leakage to the environment not only creates a liability to the operator, but also generally results in a short-term to permanent stoppage of injection at that site. Several large injection jobs have resulted in leakage to either the ground surface or the sea floor in the case of offshore wells. The most likely cause of these leakage events is that the fracture moved upward and laterally from the injection point and intersected a different well that had not been properly cemented or a natural geologic fault or fracture. Under the high down-hole pressure, the injected fluids seek out the pathway of least resistance. If cracks in a well's cement job or geological faults are present, the fluids may preferentially migrate upward and reach the land surface or the sea floor. In situations involving closely-spaced wells, the potential for communication of fluids between wells should be carefully evaluated.

Fact Sheet - Disposal in Salt Caverns

Introduction to Salt Caverns

Underground salt deposits are found in the continental United States and worldwide. Salt domes are large, finger like projections of nearly pure salt that have risen to near the surface. Bedded salt formations typically contain multiple layers of salt separated by layers of other rocks. Salt beds occur at depths of 500 to more than 6,000 feet below the surface.

Figure 26: Schematic drawing of Cavern in Bedded Salt.

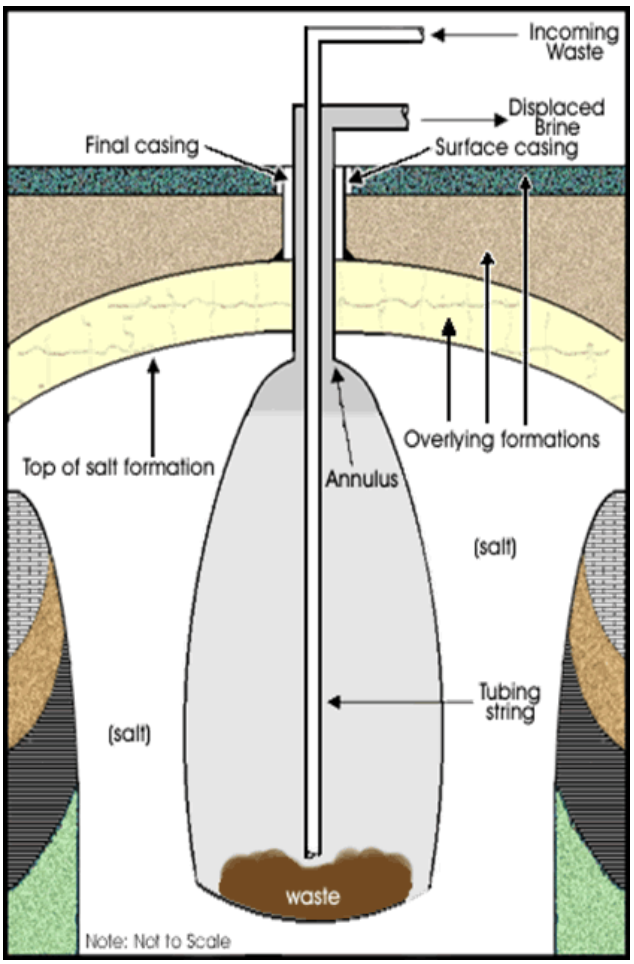


Salt caverns used for oil field waste disposal are created by a process called solution mining. Well drilling equipment is used to drill a hole from the surface to the depth of the salt formation and a smaller diameter pipe called tubing is lowered through the middle of the well. This arrangement creates two pathways into and out of the well. To form a salt cavern, the well operator pumps fresh water through one of the pipes. As the fresh water comes in contact with the salt formation, the salt dissolves until the water becomes saturated with salt. Cavern space is created by the removal of the salt-laden brine.

Use of Salt Caverns for Disposal

Salt caverns have been used for several decades to store various hydrocarbon products. More recently, their use for disposal of oil field wastes has received increased attention. In the early 1990s, several Texas brine companies obtained permits to receive oil field waste, much of which was drilling waste, for disposal into caverns they had previously developed as part of their brine production operations. Through August 2002, Texas had permitted 11 caverns at 7 locations. Interest has grown for siting new commercial disposal caverns near the coast that can receive wastes from offshore operations. As of the end of 2003, only Texas has issued permits for disposal of oil field wastes in salt caverns in the United States. Louisiana adopted cavern disposal regulations in May 2003 but has not yet permitted any disposal caverns. Several disposal caverns are also operated in Canada, and, in early 2004, Mexico announced that it was developing regulations for disposal of oil-based muds and cuttings in salt caverns.

Figure 27: Schematic drawing of a Cavern in Domal Salt.



Waste Disposal Process

Wastes are brought to the cavern site in trucks and unloaded into mixing tanks where they are blended with water or brine to make a slurry. Many exploration and production (E&P) wastes are suitable for disposal in caverns, including drilling muds, drill cuttings, produced sands, tank bottoms, contaminated soil, and completion and stimulation wastes. Grinding equipment may be used to reduce particle size. The waste slurry is then pumped into the caverns. The incoming waste displaces the brine, which is brought to the surface and either sold or injected into a disposal well. Inside the cavern, the solids, oils, and other liquids separate into distinct layers: solids sink to the bottom, the oily and other hydrocarbons float to the top, and brine and other watery fluids remain in the middle.

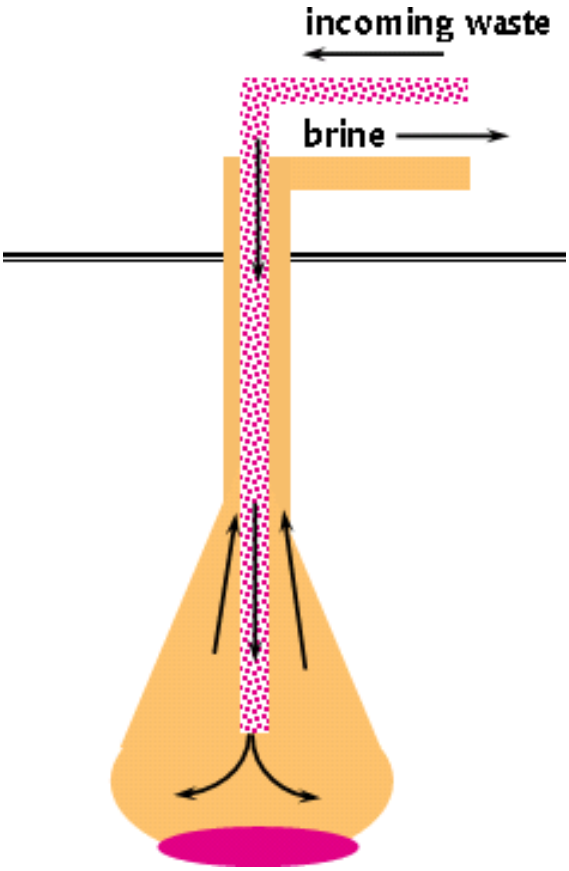
Figure 28: Waste Unloading Area at Commercial Disposal Cavern Facility

Figure 29: Injection well for cavern

In a 1997 study, the costs for cavern disposal of nonhazardous oil field waste, including drilling waste, ranged from $2 to $6/bbl. At that time, these costs were competitive with other oil field waste disposal companies operating in the same geographic area. Transportation of the wastes to the cavern facilities incurs an additional cost.

Implementation Considerations

Figure 30: Waste disposal process



Caverns are appropriate for drilling wastes because they can readily accept wastes that contain excessive levels of solids. Some other forms of drilling waste disposal, like slurry injection, require much more careful control of solids size. The oil content of the injected waste is not as critical for injection, thereby reducing operational costs.

The surface footprint and chance of surface-related problems are greatly reduced from that of a land treatment or landfill operation. Wastes are placed deep underground in an impermeable and self-healing matrix of salt. No leaks or releases have been observed from the limited number of caverns used for disposal.

At the present, there are only a few permitted disposal caverns. In order to be cost-effective, cavern sites must be located relatively close to where the waste is being generated. The cost of hauling drilling waste more than 50 to 75 miles is prohibitive.

References

- Argonne National Laboratory conducted a series of four baseline studies on the use of salt caverns for disposal of oil field wastes. These are available for downloading at: http://www.ead.anl.gov/
- The Solution Mining Research Institute Web site also provides extensive information about salt caverns: www.solutionmining.org.

Fact Sheet - Thermal Treatment Technologies

Thermal technologies use high temperatures to reclaim or destroy hydrocarbon-contaminated material. Thermal treatment is the most efficient treatment for destroying organics, and it also reduces the volume and mobility of inorganics such as metals and salts (Bansal and Sugiarto 1999). Additional treatment may be necessary for metals and salts, depending on the final fate of the wastes. Waste streams high in hydrocarbons (typically 10 to 40%), like oil-based mud, are good candidates for thermal treatment technology. Thermal treatment can be an interim process to reduce toxicity and volume and prepare a waste stream for further treatment or disposal (e.g., landfill, land farming, land spreading), or it can be a final treatment process resulting in inert solids, water, and recovered base fluids. Thermal treatment technology is generally set up in a fixed land-based installation, but some efforts are under way to develop mobile thermal treatment units and units that might fit on an offshore platform. Its application is not geographically limited, but large size and weight coupled with limited processing capacity have limited its use offshore.

Costs for thermal treatment range from $75 to $150/ton, with labour being a large component (Bansal and Sugiarto 1999). The volumes of oily waste from a single operator may not be high enough to justify continuous operation of a thermal treatment process, but contract operation of a centrally located facility that manages waste from multiple area operators can be a cost-effective alternative.

Thermal treatment technologies can be grouped into two categories. The first group uses incineration (e.g., rotary kilns, cement kilns) to destroy hydrocarbons by heating them to very high temperatures in the presence of air. Incineration is not commonly used for drilling wastes but has greater applicability for materials like medical waste. The second group uses thermal desorption, in which heat is applied directly or indirectly to the wastes, to vaporize volatile and semivolatile components without incinerating the soil. In some thermal desorption technologies, the off-gases are combusted, and in others, such as in thermal phase separation, the gases are condensed and separated to recover heavier hydrocarbons. Thermal desorption technologies include indirect rotary kilns, hot oil processors, thermal phase separation, thermal distillation, thermal plasma volatilization, and modular thermal processors.

Incineration

Incineration technologies oxidize (combust) wastes at high temperatures (typically 1,200 to 1,500 degrees C) and convert them into less bulky materials that are nonhazardous or less hazardous than they were prior to incineration (Morillon et al. 2002). Incineration is typically used to destroy organic wastes that are highly toxic, highly flammable, resistant to biological breakdown, or pose high levels of risk to human health and the environment. Higher temperatures increase treatment efficiency. Residence time in the combustion chambers can be modified to completely break down most hydrocarbons. Generally, incineration of drilling wastes is not necessary, unless operations are located in sensitive environments and other disposal options are not available. Incinerators are generally permanent (non-mobile) units. In commercial incinerators, combustion can be optimized because residence time, temperature, and turbulence within the chamber can be controlled. Commercial incinerators are also frequently equipped with pollution control devices to remove incomplete combustion products and particulate emissions and to reduce SOx and NOx emissions. Advantages of incineration include volume reduction, complete destruction (rather than isolation), and possible resource recovery. Because energy requirements for incineration relate directly to water content, costs for incinerating drilling wastes with high water contents can be high.

Rotary Kilns: Most incineration of drilling wastes occurs in rotary kilns, a mature and commercially available technology, which is durable and able to incinerate almost any waste, regardless of size or composition.

Figure 31: Rotary Kiln

A rotary kiln tumbles the waste to enhance contact with hot burner gases. Capital equipment costs for an incinerator that processes between 3 to 10 tons/hour ranges from $3 to $5 million dollars. The Canadian Crude Separator's Incineration Process (CSS) is an example of a rotary kiln process that operates under starved oxygen conditions. The unit has been permanently installed near Big Valley, Alberta, Canada. Primary chamber temperatures reach 600 to 1,000 degrees C. Venturi section temperatures reach 1,200 degrees C. The kiln handles 10 metric tons/day during a 24-hour operation period. The process can handle wastes with up to 10% hydrocarbons. Minimum costs to process solids with 10% hydrocarbons at the plant are $90 per metric ton. There is adequate mix material available to handle wastes arriving at the facility with hydrocarbon concentrations up to 40%, but prices increase with the percentage of hydrocarbons in the drilling waste (Bansal and Sugiarto 1999).

Cement Kilns: If available, a cement kiln can be an attractive, less expensive alternative to a rotary kiln. In cement kilns, drilling wastes with oily components can be used in a fuel-blending program to substitute for fuel that would otherwise be needed to fire the kiln. Cement kiln temperatures (1,400 to 1,500 degrees C) and residence times are sufficient to achieve thermal destruction of organics. Cement kilns may also have pollution control devices to minimize emissions. The ash resulting from waste combustion becomes incorporated into the cement matrix, providing aluminium, silica, clay, and other minerals typically added in the cement raw material feed stream.

Thermal Desorption

Thermal desorption uses a non-oxidizing process to vaporize volatiles and semi-volatiles through the application of heat. Because thermal desorption depends on volatilization, treatment efficiency is related to the volatility of the contaminant. Thus, thermal desorption easily removes light hydrocarbons, aromatics, and other volatile organics, but heavier compounds such as polycyclic aromatic hydrocarbons are less easily removed. Low-temperature thermal desorption systems typically operate at 250 to 350 degrees C and may be sufficient to treat wastes with light hydrocarbons, aromatics (e.g., benzene, toluene, ethylbenzene, and xylenes), and other volatile organics, which are easily removed. High-temperature systems may operate at temperatures up to 520 degrees C, and can produce lower final oil contents for wastes with heavier compounds such as polycyclic aromatics (E&P Forum 1993).

Thermal desorption produces various secondary waste streams, including solids, water condensate, and oil condensate, each of which may require analysis to determine the best recycle/disposal option. In most cases, the liquids are separated and reused in drilling mud to improve the economics of this method. In other cases (for example, original wastes with high salts and metals contents), additional treatment may be required to reduce the potential for environmental impact from these streams.

Figure 32: Thermal Desorption

Capital equipment costs for a thermal desorption plant that processes between 3 to 10 tons/hour range from $3 to $5 million dollars. Contractor operator treatment costs range from $75 to $150/ton (Bansal and Sugiarto 1999). Many factors can impact treatment costs, including oil and moisture content of the waste, particle size distribution of the solids, organic composition and volatility, management of the hydrocarbon by-product, and management of the water product. Economics may improve in cases where the thermal desorption process is operated as part of the overall production facility.

Many variations of the thermal desorption process have been developed and are applicable for treating drilling wastes. Examples include indirect rotary kilns, hot oil processors, thermal phase separation, thermal distillation, thermal plasma volatilization, and modular thermal processors, each of which is described below.

Indirect Rotary Kilns: Indirect rotary kilns use hot exhaust gases from fuel combustion to heat the drilling wastes. The technology consists of a rotating drum placed inside a jacket. Heat is supplied through the wall of the drum from the hot exhaust gas that flows between the jacket

and the drum. The drilling wastes are agitated and transported through the processor inside the rotating drum. Treated solids are recirculated to prevent the formation of an isolating layer of dried clay in the inside of the drum. Because the overall heat transfer from the exhaust to the material is low, relatively large heating surfaces are required, and the process units are correspondingly large. The units typically heat the wastes to about 500 degrees C, which provides for the efficient removal of oil from the wastes, but which can lead to thermal degradation and decomposition of residuals in the recovered solids. The processes typically retain the wastes for about 30 to 150 minutes (Thermtech undated).

Hot Oil Processors: In hot oil processors, heat is transported to the drilling wastes by circulating hot oil inside hollow rotors. The rotors also agitate and create the required axial transport in the bed. Conventional fuels provide the primary heat source for the hot oil. Large heating surfaces are required because (1) there is a relatively low heat transfer coefficient between the hot oil and the waste material inside the processor, and (2) commercial hot oils have maximum operating temperatures that are close to the required process temperature, which limits the useable temperature difference for the heat transfer. Some units augment the heat from the hot oils with electric heating on part of the heat surface to reach the temperature needed for complete removal of the oil in the waste. Retention times for complete removal of oils are about 30 to 150 minutes (Thermtech undated).

Thermal Phase Separation: The thermal separation process (TPS) consists of five subsystems. In the first, the drilling wastes are screened to remove foreign matter prior to delivery to the desorption chamber. Next, the shell of the chamber is heated externally with a series of burners fuelled by propane, natural gas, diesel, or recovered drilling fluid. The drilling wastes are heated indirectly to raise the temperature of the drilling waste to the boiling point of the hydrocarbons (usually about 220 degrees C, but sometimes up to 500 degrees C), where they are volatilized and separated from the host matrix under a vacuum. Screw augers, which slowly draw the wastes through the inner heating shell, ensure suitable agitation and thorough heating of the solids matrix. The water vapour and gaseous hydrocarbons extracted in the desorption chamber are rapidly cooled by direct contact with water sprays fed with recirculated process water. The condensed liquids and recirculated quench water are then sent to an oil-water separator, where the recovered fluid is collected, analyzed, and recycled. Treated solids are contained and tested prior to use as an onsite fill material. TPS processing removes 99% of hydrocarbons from the feedstock (Zupan and Kapila 2000). The recovered water is cooled and contained for recirculation.

Advantages of TPS over rotary kilns or directly fired desorption systems are more sophisticated air emissions control, the ability to treat materials with up to 60% undiluted oil (because there is no potential for combustion), and the opportunity of visual inspection during operations. The economic value of the process lies in the quality of the recovered base oil and its readiness for reuse or resale (Zupan and Kapila 2000). Mobile TPS units can treat 10 to 50 tons per hour of waste material, and highly mobile, heli-transportable equipment allows for treating drilling wastes in remote locations. A pilot TPS unit can generate results representative of full-scale units, allowing reliable pre-testing of drill cuttings treatment (Snyder 1999). TPS systems are used for oil-based drilling wastes in environmentally sensitive areas.

Thermal Distillation: Because constituents of liquid mixtures evaporate at different temperatures, thermal distillation allows for the separation of solids, liquids, and the different constituents of liquids. In high-temperature thermomechanical conversion and cracking, drill cuttings are distilled and cracked to boil off water and oil. Sometimes the vapours are condensed to allow for recovery. In the thermomechanical process, heat is produced internally in the drilling waste by friction forces generated by intense agitation. High mechanical shear combined with in-situ heat generation creates an environment that promotes flash evaporation of water and hydrocarbons. The efficient turbulent mixing promotes an efficient steam distillation of the oils, which makes it possible to vaporize oils at a temperature well below their atmospheric vaporization point (about 200 to 350 degrees C), thereby eliminating the risk for thermal degradation. The intense agitation in the process mill requires that the layer of

abrasion-resistant material welded on the active surfaces of the mill be refurbished regularly. Thermomechanical units operating today recover solids with residual oil levels less than or equal to 1,000 ppm. After removing free residual oil in settling tanks or oil separators, the recovered water (with less than 15ppm oil) can be reused, discharged to the sea, or sent to available wastewater treatment facilities.

Benefits of thermomechanical desorption include the following:

- Direct mechanical heating, which eliminates the need for large heating surfaces and complex heating systems.
- The ability to use engines, turbines, or electric motors to generate mechanical energy, which allows for compact designs.
- Limited process temperatures and short retention times required for complete removal of oil from the solids (6 to 12 minutes for solids and 15 to 30 seconds for the oil), which significantly reduces the risk for thermal degradation of the valuable mud oils (Thermtech undated) and the quantity and cost of the heat that is required.

In lower-temperature thermal stripping, the oil is not cracked, and can therefore be reused. The treated cuttings resulting from distillation can be reused, if the concentrations of heavy metals and salts are acceptable.

Thermal Plasma Volatilization: As of January 2004, thermal plasma volatilization has not yet been used for the treatment of drilling wastes, but is being considered for that purpose. Thermal plasma results when a common gas is heated to extremely high temperatures (up to 15,000 degrees C). The technology is used for various applications including metallurgy; steel making; and treating medical, industrial, and petroleum wastes. It is also being used to treat oil-contaminated soils that include substances such as chlorides, which are unsuitable for a combustion process because of their potential to generate dioxins and furan compounds as by-products. The process uses a plasma reactor, which contains a plasma torch operating in an inert atmosphere. The waste material is fed into the reactor. In the reactor, the torch, whose jet temperature is about 15,000 degrees C, is used to heat the waste to up to 900 degrees C without combustion, causing any hydrocarbons to volatilize. In subsequent stages, these hydrocarbons are condensed, and most are reclaimed as clean oil and returned to a process stream. The resulting solids are inert and contain less than 0.01% hydrocarbons. The reduction in mass of the waste materials is typically about 70%, and the reduction in volume is typically about 85%. If the wastes have toxic materials, such as heavy metals, a subsequent plasma vitrification process can be used. In plasma vitrification, the toxic waste goes to a vitrification reactor, where temperatures above 1,600 degrees C are maintained and where chemical and physical reactions form ceramic and ferrous matrices in liquid forms. When tapped from the reactor, the toxic materials become solid, inert phases, which can be used in construction and metallurgical applications.

Advantages of the process include significant reductions in waste volume, reduced costs for preparation and transport of wastes, avoidance of harmful stack emissions, compact installation, and higher energy efficiency than combustion. (With thermal plasma volatilization, 85% of the energy is transferred as heat, compared with about 20% for combustion processes.) A disadvantage is the potentially high cost of the process.

Modular Thermal Processors: An example of a thermal technology that can be used offshore as well as onshore is the TCC RotoMill™ thermal processor (Thermtech undated, TWMA undated). This modular mobile system was developed to address the following offshore considerations: need for low weight (to meet crane lift restrictions), need for small footprint (to fit within limited space on most offshore installations), and processing rates high enough to meet cuttings generation rates. The process is designed to flash-evaporate the fluid phase from drilling wastes. It uses a combination of electrical and mechanical energy (through a hammer mill) to evaporate the fluid phases. The process operates at temperatures that vary depending on the type of waste and the boiling point of associated hydrocarbons. The evaporated fluids

are retained and then condensed, allowing selective recovery of the individual fluids (typically hydrocarbons and water). The remaining solids are discharged as an inert powder, and the recovered fluids can be reused or recycled. The process generates no atmospheric emissions. The unit is small enough to be truck-mounted for onshore use at a well site or offshore at sites with low waste-generation rates. Larger units that can process up to 6 metric tons per hour can be used onshore or offshore for larger hole sections. Advantages of the system include simplified logistics for offshore waste management, reduced environmental impact, improved safety, and reduced costs.

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Economic Considerations

Various examples taken from the literature provide a range of cost comparisons for using oil-based muds and injecting the cuttings, using synthetic-based muds and discharging the cuttings, and hauling drilling wastes to shore for disposal. Although many of the references show that slurry injection is the most cost-effective option at the studied site, no single management option is consistently identified as the least or the most costly. This confirms the importance of conducting a site-specific cost-benefit analysis. In addition to the economic considerations of the initial disposal well design, it is useful to conduct a thorough evaluation of the fracturing and injection well design to insure that long-term mechanical isolation can be achieved in the proposed injection zone.

Three factors are critical when determining the cost-effectiveness of slurry injection:

(1) The volume of material to be disposed of – the larger the volume, the more attractive injection becomes in many cases. The ability to inject onsite avoids the need to transport materials to an offsite disposal location. Transportation cost becomes a significant factor when large volumes of material are involved. In addition, transporting large volumes of waste introduces safety and environmental risks associated with handling, transferring, and shipping. Transportation also consumes more fuel and generates additional air emissions.

(2) The regulatory climate – the stricter the discharge requirements, the greater the likelihood that slurry injection will be cost-effective. If cuttings can be discharged at a reasonable treatment cost, then discharging is often the most attractive method. Regulatory requirements that prohibit or encourage slurry injection play an important role in the selection of disposal options.

(3) The availability of low-cost onshore disposal infrastructure – several disposal companies have established extensive networks of barge terminals along the Louisiana and Texas coasts to collect large volumes of wastes brought to shore from offshore Gulf of Mexico platforms. They subsequently dispose of them through either sub-fracture injection or placement into salt caverns at onshore locations. Through the economy of scale, the onshore disposal costs are not high, and much of the offshore waste that cannot be discharged is brought to shore and disposed of at these facilities. Most other parts of the world do not have an effective, low-cost onshore infrastructure. Thus, in those locations, onshore disposal is often a greater environmental and human health risk than the onsite disposal options.

References

- DOE asked Argonne National Laboratory to evaluate the feasibility of slurry injection technology. Argonne completed its evaluation in 2003 and prepared three documents: a technical report, a compendium of relevant state and federal regulations, and a brochure that describes the technology in terms suitable for nontechnical audiences. References for the two reports and the brochure are listed below and can be downloaded from Argonne's web-site.
- Argonne, 2003, "An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes," brochure prepared by Argonne National Laboratory for the U.S. Department of Energy, Office of Fossil Energy, National Petroleum Technology Office, September, 20 pp.
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Appendices

Technology Identification Module – Process
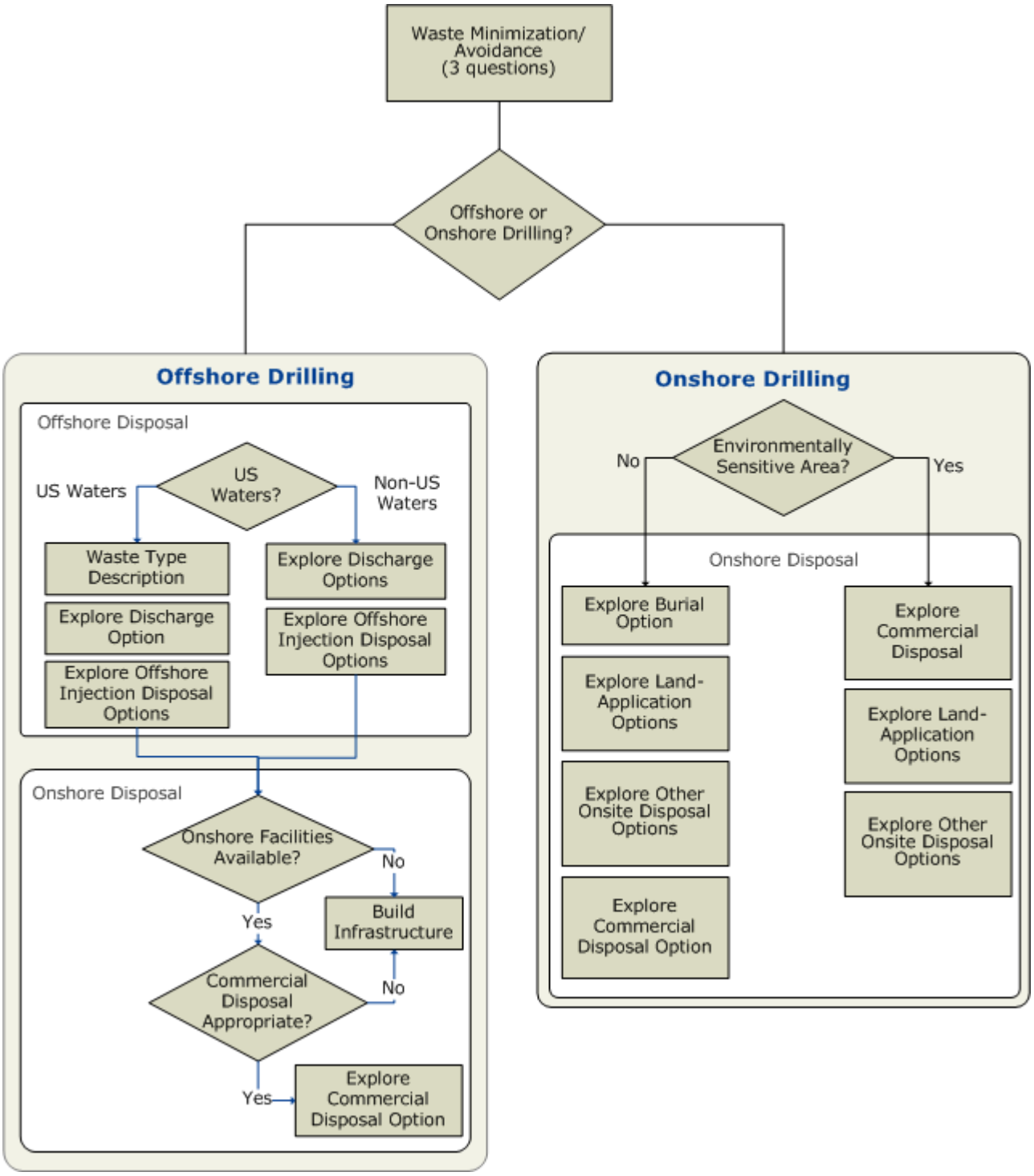
Figure 33: Drilling waste management identification process chart