

Executive Order 12612, and it has been determined not to have any federalism implication that warrants the preparation of a federalism assessment.

List of Subjects in 14 CFR Part 399

Applicability and effects, Operating authority, Rates and tariffs; Accounts and reports, Hearing matters, Rulemaking prosecutions, Enforcement, Other policies, Disclosure of information, Federal preemption.

Accordingly, the Department of Transportation (DOT) proposes to amend 14 CFR Part 399 as follows:

PART 399—STATEMENT OF GENERAL POLICY

1. The authority citation for Part 399 would continue to read as follows:

Authority: 101, 102, 105, 204, 401, 402, 403, 404, 405, 406, 407, 408, 411, 412, 414, 416, 801, 1001, 1002, 1102, 1104, Pub. L. 85-726, as amended, 72 Stat. 737, 740, 92 Stat. 1708, 72 Stat. 743, 754, 757, 758, 7670, 763, 766, 767, 768, 769, 770, 771, 782, 788, 7979, 49 U.S.C. 1301, 1302, 1305, 1324, 1371, 1372, 1373, 1374, 1375, 1376, 1377, 1378, 1379, 1381, 1382, 1384, 1386, 1461, 1481, 1482, 1502, 1504; Pub. L. 96-354, 5 U.S.C. 601, unless otherwise noted.

2. Add a new § 399.85 to Subpart G to read as follows:

§ 399.85 Enforcement policy regarding illegal rebating in foreign air transportation.

(a) It is the policy of the Department to review complaints alleging illegal rebating in foreign air transportation on a case-by-case basis to determine whether it is in the public interest and consistent with the Department's transportation policy goals to initiate an investigation or to bring enforcement action on the Department's behalf.

(b) An investigation or other enforcement action may be undertaken only when clear evidence is presented that rebating in violation of section 403(b) of the Act has occurred and that such rebating is adversely affecting a substantial number of persons and is:

- (1) Occurring in connection with fraudulent or deceptive practices associated with the holding out or sale of fares or rates involving a rebate, or
- (2) Offered on an invidiously discriminatory basis such as rebates limited on the basis of race, creed, color, sex, religious or political affiliation, or national origin, or
- (3) Adversely affecting competition because the rebates are associated with activities that violate the antitrust laws.

(c) For purposes of this policy, a rebate may be found to be connected with fraudulent or deceptive practices where, for example, a rebate is offered in connection with a "bait-and-switch"

scheme whereby the seller uses the rebate offer to attract a client and then pressures the customer to purchase a higher-fare ticket.

(d) For purposes of this policy a rebate offer will not be found to affect competition adversely when the only effect of the offer is to divert passengers from one airline or ticket seller to another.

§ 399.80 [Amended]

3. Remove and reserve paragraph 399.80(g) in its entirety.

4. Remove and reserve paragraph 399.80(h) in its entirety.

Issued in Washington, DC, on October 17, 1988.

Jim Burnley,

Secretary of Transportation.

[FR Doc. 88-24241 Filed 10-20-88; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 435

[FRL-3463-7]

Oil and Gas Extraction Point Source Category, Offshore Subcategory; Effluent Limitations Guidelines and New Source Performance Standards; New Information and Request for Comments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of data availability and request for comments.

SUMMARY: EPA is announcing today the availability for public comment of new technical, economic and environmental assessment information relating to the development of BAT and NSPS regulations under the Clean Water Act governing the discharge of drilling fluids and drill cuttings in the oil and gas extraction point source category, offshore subcategory. EPA requests comment on this new information. This notice is part of a rulemaking process that commenced formally on August 26, 1985 with EPA's proposal of effluent limitations guidelines and new source performance standards for the offshore subcategory (50 FR 34592). The comment period for the original proposal closed on March 15, 1986.

DATE: Comments on this new information must be submitted by December 5, 1988.

ADDRESSES: Comments should be sent to Mr. Dennis Ruddy, Industrial Technology Division (WH-552), Environmental Protection Agency, 401 M Street SW., Washington, DC 20460.

The supporting information and data described in this notice will be available for inspection and copying at the EPA Public Information Reference Unit, Room 2402 (Rear of EPA Library) PM-231, 401 M Street SW., Washington, DC 20460. The EPA public information regulation (40 CFR Part 2) provides that a reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT:

Technical information may be obtained from Mr. Dennis Ruddy at the above address, or call (202) 382-7131. Economic information may be obtained from Ms. Ann Watkins, Economic Analysis Branch (WH-586), at the above address or call (202) 382-5387. Environmental assessment information may be obtained from Ms. Alexandra Tarnay, Monitoring and Data Support Division (WH-553), at the above address or call (202) 382-7036.

SUPPLEMENTARY INFORMATION: On August 26, 1985, EPA proposed effluent limitations guidelines and new source performance standards for the oil and gas extraction point source category, offshore subcategory, 50 FR 34592. The proposal included BAT, BCT, and NSPS regulations covering produced water, drilling fluids, drill cuttings, produced sand, deck drainage, well treatment fluids and sanitary and domestic waste discharges from offshore oil and gas facilities. Since issuing the August 26, 1985 proposal, the Agency has received comments and collected additional data on numerous aspects of this rulemaking.

Today's notice relates to the development of BAT and NSPS regulations governing the discharge of drilling fluids and drill cuttings. EPA is announcing today the availability for public comment of new technical, economic and environmental assessment information relating to the regulation of those waste streams. This notice presents a variation on the originally proposed BAT and NSPS limitations on the mercury and cadmium content of discharged drilling fluids. It also describes EPA's initial investigation of an oil content limitation that could be applied to drilling waste streams at the BAT and NSPS levels of control.

The Agency has determined that it will promulgate the final regulations for the offshore subcategory in phases. Discharge regulations for drilling fluids and drill cuttings are scheduled for promulgation first. Regulations governing the other waste streams that were included in the August 26, 1985 proposal will be addressed in separate Federal Register notices. The Agency intends, in the next several months, to

issue an additional Federal Register notice repropounding BCT effluent limitations guidelines for drilling fluids and drill cuttings.

Today's notice is organized as follows:

Summary of Part 1

Summary of Part 2

Part 1

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Part 2

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- VI. Performance Data
 - A. Field Sampling
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VIII. Analytical Method for Total Oil Content

IX. Request for Comments

Appendix A—Proposed Method 1651, Oil Content and Diesel Oil in Drilling Muds and Drill Cuttings by Retort Gravimetry and GCFID

Summary of Part 1

Part 1 of today's notice announces the availability of additional information and presents discussion and preliminary conclusions on new data concerning BAT and NSPS controls on the drilling fluids and drill cuttings waste streams. It also discusses the potential applicability of several computer models to analyze the dispersion of drilling fluids and produced water waste streams.

Part 1 begins, in Section I, with a summary of the portions of the August 26, 1985 proposal that are pertinent to material presented in today's notice. The discussion that follows in Sections II, III, IV and V deals first with technical issues, then with economic and cost issues, and finally with environmental assessment issues relating to BAT and NSPS controls on drilling fluids and drill cuttings.

Subpart A of Section III ("Drilling Fluid Toxicity Test") discusses the proposed analytical method for determining the toxicity of drilling fluids. The discussion summarizes major industry comments on reliability and variability of the proposed toxicity test method and presents the Agency's plans for further evaluation of the test method.

In Subpart B of Section II ("Discharge of Oil in Water-Based Fluids"), the Agency presents new information relating to its proposal to prohibit the discharge of detectable amounts of diesel oil in drilling fluids and drill cuttings. Industry commenters have argued that the discharge of diesel oil should not be prohibited because diesel oil is the most effective agent for use in freeing stuck drill pipe. The discussion summarizes three studies of the relative effectiveness of diesel oil and mineral oil for freeing stuck pipe (the 1983-1984 API Survey, the 1986 Offshore Operators Committee Survey and the 1986-1987 EPA/API Diesel Pill Monitoring Program). It also presents and explains the Agency's renewed determination, in light of this new data, that the proposed prohibition on the discharge of diesel oil in detectable amounts continues to be appropriate for the BAT and NSPS levels of control. Subpart C of Section II ("Analytical Method for Oil Detection") and Appendix A of this notice present a proposed modification to the originally proposed analytical method for the detection of diesel oil in drilling fluids and drill cuttings.

In Subpart D of Section II ("Metals Limitations"), the Agency is presenting two sets of mercury and cadmium effluent limitations that may be applicable to discharged drilling fluids. The Agency formulated a second set of effluent limitations for mercury and cadmium based upon information submitted by commenters in response to the set of effluent limitations presented and discussed in the proposed regulations.

Economic and costing issues are presented in Sections III and IV of Part 1. The Agency has recosted compliance with the proposed BAT and NSPS regulations governing the discharge of drilling fluids and drill cuttings based upon new technical and cost information. Section III summarizes the changes to the costing information and assumptions. Section IV presents a summary of the economic impact analysis revised according to the new information and assumptions.

Under the subpart of Section III titled "Toxicity Failure Rate for Drilling Fluids," the Agency presents new data and preliminary conclusions concerning industry's expected rate of failure of the proposed toxicity limitation (30,000 ppm suspended particulate phase basis) by drilling fluids that contain no added oil. This discussion also includes the Agency's revised estimate of the annual industry cost of compliance with the toxicity limitation for drilling fluids.

The remaining subparts of Section III present updated or refined information that affects various factors used in estimating annual compliance costs. The affected factors are the estimate of the number of wells to be drilled offshore per year, model well characteristics, transportation and disposal on shore of drilling wastes that do not comply with the proposed limitations and standards, the frequency of use of oil based muds as opposed to water based muds, the cost differential between diesel oil and mineral oil, pollutant reduction estimates, expected failure rates for the static sheen test and monitoring costs.

Utilizing the new information and assumptions presented in Section III, Section IV summarizes the revised industry profile, economic impacts and other economic information concerning the proposed BAT and NSPS controls on drilling fluids and drill cuttings. Section IV also explains the Agency's preliminary conclusion that despite overall higher costs since proposal, the revised estimates of cost are economically achievable.

Finally, Section V summarizes a literature search concerning mercury

and cadmium in barite, a constituent of drilling fluids, and the environmental consequences of the discharge of drilling fluids containing barite. Section V concludes with the Agency's evaluation of several computer models that have potential application in the prediction of dispersion of discharged drilling wastes and produced water.

Summary of Part 2

Part 2 of today's notice presents new information on the performance, costs and applicability of certain thermal technologies and solvent extraction technologies for treating drilling fluids and drill cuttings to reduce their oil content. Based on this information, the agency has begun to consider an oil content limitation of up to 1% by weight, whole sample basis, governing the discharge of drill cuttings wastes at the BAT and NSPS levels of control.

Sections I through III of Part 2 summarize the Agency's preliminary determinations regarding the applicability of an oil content limitation to drilling waste streams, discuss the regulatory background giving rise to EPA's investigation of this regulatory option, and present an overview of the thermal distillation, thermal oxidation and solvent extraction treatment technologies that are under review by the Agency.

Section IV of Part 2 describes these technologies in greater detail. Section V discusses in greater detail the potential applicability of these technologies to drill cuttings and drilling fluids, concluding that the technologies appear suitable as the basis for regulation of drill cuttings but not drilling fluids. Section VI presents preliminary estimates of pollutant reductions and the costs associated with treatment of drill cuttings and drilling fluids using these technologies. Section VII presents performance data for one variety of the thermal distillation technology. Section VIII estimates the quantities of drill cuttings and water-based drilling fluids that would not meet an oil content limitation of 1% or less. Section IX presents EPA's preliminary conclusion that the revised analytical method presented in Appendix A is appropriate for quantification of oil content of drill cuttings and drilling fluids. Section X requests comment on issues pertaining to development of BAT and NSPS oil content controls for drill cuttings.

The Agency is inviting comment only on the information presented today and regulatory approaches relevant to BAT and NSPS effluent limitations for the drilling fluids and drill cuttings waste streams, and not on other aspects of the August 26, 1985 proposed rule.

The Agency intends, in the next several months to issue an additional **Federal Register** notice related to this rulemaking for the drilling fluids and drill cuttings waste streams. The topics of the future notice are expected to include: Reproposal of BCT effluent limitations guidelines, results and conclusions from the drilling fluids toxicity test variability study (mentioned in Section II of Part I of today's notice), and other data or options that have not been addressed in **Federal Register** notices prior to that time.

Part 1

I. Summary of Proposed Regulations

On August 26, 1985, EPA proposed regulations to control the discharge of wastewater pollutants from the offshore oil and gas extraction industry, a subcategory of the oil and gas extraction category (50 FR 34592) (the "1985 proposal"). The proposed regulations included NSPS and effluent limitations guidelines based upon BAT and BCT. The proposed regulations also included an amendment to the BPT definition of "no discharge of free oil." The waste streams covered by the proposed regulations were produced water, drilling fluids, drill cuttings, deck drainage, well treatment fluids, produced sand and sanitary and domestic wastes.

The notice of proposed rulemaking and the supporting rulemaking record fully explain the proposal for all of the waste streams. For the purposes of this part of today's notice, a summary of the proposed regulations regarding only drilling fluids and drill cuttings is contained below.

A. Drilling Fluids

1. **BAT.** The proposed BAT regulations for drilling fluids would prohibit the discharge of free oil as measured by the static sheen test. The static sheen test would provide for a determination of the presence of free oil *prior* to discharge. The static sheen test method was included in the proposed regulations as an appendix (50 FR 34627). The pollutant parameter free oil was proposed to be regulated as a BAT "indicator" pollutant for control of the discharge of priority pollutants based upon information gathered on the concentration of priority pollutants in both drilling fluids and the specific additives used in the drilling fluid formulations. The parameter free oil is proposed to be used as an indicator pollutant for priority pollutants because it would be technologically infeasible to develop effluent limitations for all of the individual priority

pollutants. The priority pollutants that would be controlled include benzene, toluene, ethylbenzene and naphthalene. The Agency has determined that the prohibition on the discharge of free oil as measured by the proposed static sheen test method would result in BAT-level control for the toxics of concern in drilling wastes.

The proposed "no discharge of free oil" limitation differs from the current 40 CFR Part 435 requirement (BPT) that is based upon the application of best practicable control technology currently available (BPT). The current BPT requirement prohibits the discharge of free oil that would "cause a film or sheen upon or a discoloration on the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines". 40 CFR 435.11(d). The compliance monitoring procedure is a visual inspection of the receiving water *after* discharge.

The BPT limitation of "no discharge of free oil" was originally intended to prohibit the discharge of drilling wastes that, when discharged, would cause a sheen on the receiving water. This limitation and the current definition were established to be consistent with the oil discharge provisions of section 311 of the Clean Water Act. The Agency did not intend that discharged drilling fluids be considered "sludge". For this reason, the Agency proposed in the August 26, 1985, notice to amend the current definition for the purposes of BPT, BAT, BCT and NSPS by excluding language that prohibits the deposition of sludge beneath the surface of the receiving water. This would allow the discharge of drilling fluids, provided that other effluent limitations are met.

The proposed regulations would also prohibit the discharge of diesel oil in detectable amounts. The analytical method for detection of diesel oil was included in the proposed regulations as an appendix (50 FR 34628). The pollutant parameter diesel oil was also proposed to be regulated as a BAT "indicator" pollutant for control of the discharge of priority pollutants contained in diesel oil.

In the preamble to the 1985 proposed regulations, the Agency recognized that diesel oil should be regulated at the BAT level because it contains toxic organic pollutants. Diesel oil was proposed to be designated an indicator pollutant for the BAT and NSPS levels to control the amounts of the individual toxic organic pollutants that it contains. The listed priority pollutants found in various diesel oils can include, benzene, toluene,

ethylbenzene, naphthalene, phenanthrene, fluorene, and phenol. Diesel oil may contain from 20 to 60 percent by volume aromatic hydrocarbons. The aromatic hydrocarbons, such as benzenes, naphthalenes, and phenanthrenes, constitute the more toxic components of petroleum products such as diesel oil. Diesel oil also contains a number of nonconventional pollutants, including polynuclear aromatic hydrocarbons such as methylnaphthalene, dimethylnaphthalene, methylphenanthrene, and other alkylated forms of each of the listed toxic pollutants.

Because "diesel oil" is neither a listed toxic pollutant nor a listed conventional pollutant it is non-conventional pollutant. The parameter diesel oil is used as an indicator for the toxic organic pollutants that it is composed of because it would be technologically infeasible to develop effluent limitations for all of the individual toxic organic pollutants. The Agency has determined that control of these toxic organic pollutants by the regulation of "diesel oil" as proposed represents BAT-level of control of the toxics of concern.

The proposed regulations would also limit the toxicity of discharged drilling fluids with a 96-hour LC50 toxicity limitation. The LC50 limitation proposed is 3.0 percent by volume of the diluted suspended particulate phase, as a minimum (no single analysis to exceed). The analytical method for determining the 96-hour LC50 toxicity is a bioassay method that was also included in the proposed regulations as an appendix (50 FR 34631). The purpose of the LC50 limitation is to reduce the levels of toxic constituents in drilling fluid discharges, including additives such as oil or lubricity agents and some of the numerous specialty additives that may contribute significantly to the toxicity of the drilling fluids.

The proposed regulations would also prohibit the discharge of oil-based drilling fluids. This limitation continues the effective prohibition on the discharge of oil-based drilling fluids that results from the BPT requirement of "no discharge of free oil". The oil present in such fluids would serve as an "indicator" pollutant to control the discharge of priority pollutants contained in the oils added to or present in oil-based drilling fluids at the BAT level of control. The priority pollutants that would be controlled include benzene, toluene, ethylbenzene and naphthalene. The Agency has determined that the prohibition on the discharge of oil-based drilling fluids

would result in BAT-level control for the toxics of concern in these drilling wastes.

The proposed regulations would also limit the amounts of mercury and cadmium that are in discharged drilling fluids. The proposed effluent limitations for mercury and cadmium are 1 mg/kg each, dry weight basis in the whole drilling fluid, as a maximum limitation (*i.e.*, no single analysis to exceed). These limitations would apply to the discharged drilling fluid. Compliance with these limitations would likely be accomplished by control of these priority pollutants in the barite component of the drilling fluid.

2. *BCT*. As stated previously, today's notice presents information for the purpose of promulgating BAT and NSPS regulations from drilling fluids and drill cuttings. The August 26, 1985, proposal did include a BCT limitation which would prohibit the discharge of free oil in these wastes as measured by the static sheen test. The static sheen test method was included in the proposed regulations as an appendix (50 FR 34627). The pollutant parameter free oil was proposed to be regulated at the BCT level of control. However, with the exception of free oil, BCT requirements for drilling fluids were reserved for future rulemaking until after the promulgation of the general BCT methodology. The general BCT methodology was subsequently promulgated by EPA on July 9, 1986 (51 FR 24974). The Agency intends to issue a separate **Federal Register** notice to propose BCT for drilling fluids (and drill cuttings). Subsequently, the Agency will issue final BAT, BCT and NSPS regulations for drilling fluids and drill cuttings.

3. *NSPS*. The proposed regulations would establish NSPS limitations for free oil, oil-based drilling fluids, diesel oil, toxicity, mercury and cadmium as described above for the BAT level of control.

The proposed regulations included definitions for certain terms used to classify a "new source" for the offshore subcategory. These definitions would facilitate the application of the term "new source" to activities covered in this subcategory, including mobile and fixed exploratory and development drilling operations as well as production operations. Refer to the 1985 proposal notice for a detailed discussion of the Agency's intent in applying the new source designation. Comments were received regarding the proposed new source definition, but the Agency is not presenting any changes to the proposed definition at this time.

B. Drill Cuttings

1. *BAT*. The proposed BAT regulations for drill cuttings would prohibit the discharge of free oil as measured by the static sheen test. The pollutant parameter free oil was proposed to be regulated as an "indicator" pollutant at the BAT level for control of the discharge of priority pollutants in the oil contained in drill cuttings. Free oil is proposed to be used as an indicator pollutant for the priority pollutants contained in the oil because it would be technologically infeasible to develop effluent limitations for each of the individual priority pollutants contained in free oil. The priority pollutants that would be controlled include benzene, toluene, ethylbenzene and naphthalene. The Agency has determined that the prohibition on the discharge of free oil would result in BAT-level control for the toxics of concern in drilling wastes.

In addition, the proposed regulations would prohibit the discharge of diesel oil in detectable amounts. The pollutant parameter diesel oil was also proposed to be regulated as an "indicator" pollutant at the BAT level for control of the discharge of priority pollutants in diesel oil contained in drill cuttings. Diesel oil is proposed to be used as an indicator pollutant for the priority pollutants contained in diesel oil because it would be technologically infeasible to develop effluent limitations for all of the individual priority pollutants. The priority and non-conventional pollutants to be controlled by the use of diesel oil as an indicator pollutant are the same as that discussed above for the BAT-level of control for drilling fluids.

The proposed regulations would also prohibit the discharge of drill cuttings containing oil-based drilling fluids. As noted previously, such fluids would serve as "indicator" pollutants to control, at the BAT level, the discharge of priority pollutants contained in the oils added to or present in oil-based drilling fluids and transferred to drill cuttings.

2. *BCT*. The August 26, 1985 proposed BCT regulations for drill cuttings would prohibit the discharge of free oil as measured by the static sheen test. The pollutant parameter free oil was proposed to be regulated at the BCT level for control of the discharge of oil contained in drill cuttings.

With the exception of free oil, BCT requirements for drill cuttings were reserved for future rulemaking until after the promulgation of the general BCT methodology. The general BCT methodology was subsequently

promulgated by EPA on July 9, 1986 (51 FR 24974). The Agency intends to propose BCT in a separate Federal Register notice for drill cuttings (and drilling fluids).

3. *NSPS*: The proposed regulations would establish NSPS limitations for the discharge of drill cuttings containing free oil, drill cuttings associated with oil-based drilling fluids, and drill cuttings that contain diesel oil as described above.

II. New Technical Information Related To the Proposed BAT/NSPS regulations

A. Drilling Fluid Toxicity Test

The proposed BAT and NSPS regulations would regulate drilling fluids by specifying a limit on the toxicity of the discharged fluid as determined through laboratory testing of samples of the fluids. The testing would consist of exposing test organisms to solutions containing different concentrations of the fluids. The test results would be used to determine concentration values lethal to 50% of the test organisms, *i.e.*, LC50 values. These LC50 values would be used to determine compliance with the toxicity limitation. The proposed BAT and NSPS regulations contain a limitation on the LC50 of discharged drilling fluids of 3.0 percent by volume of the diluted suspended particulate phase ("SPP basis") of the drilling fluids wastestream.

EPA accounted for variation in drilling fluid toxicity testing during the process of establishing the proposed toxicity limitation. The Agency proposed a limitation equal to the measured toxicity of the most toxic of the eight generic water-based drilling fluids. (The eight generic drilling fluids are identified in Appendix B of the August 26, 1985 proposal; 40 FR 34632.) Test method variability and analytical variability were accounted for in the proposed limitation because they were inherent components of the procedures used by the Agency in performing the toxicity testing and subsequent calculations. No explicit additional allowances for variation in the test method (intra- or inter-laboratory variability) or variation in "batches" of discharged waste material were used in establishing the proposed toxicity limitation. Moreover, the Agency has not historically provided for such additional allowances in the development of effluent limitations.

EPA has received numerous comments on the proposed toxicity limitation. In particular, industry commented that the toxicity limits may be failed as a result of intra- and inter-laboratory variability in test results.

One existing source of data for use in evaluating inter-laboratory variability is the study that was performed to aid the Agency in the selection of laboratories to conduct toxicity tests for EPA under contract. This data collection effort was part of an Agency "invitation for bid" (IFB) contracting process to provide acute toxicity test method performance information by laboratories attempting to qualify for contract analytical services to the Agency.

A detailed description of the statistical analysis on the IFB data is described in a paper titled "Toxicity Testing of Drilling Fluids: Assessing Laboratory Performance and Variability" (R.C. Bailey, B.P. Eynon), which is available in the record for this rulemaking. The Bailey-Eynon assessment also evaluates intra-laboratory variability using additional data from the EPA Gulf Breeze Laboratory. The American Petroleum Institute (API) has criticized the Bailey-Eynon assessment in a paper titled "Variability in Drilling Fluid Toxicity Tests" (J.E. O'Reilly, L.R. LaMotte). This paper also is included in the rulemaking record.

In order to draw final conclusions concerning variability of toxicity test results, the Agency is currently conducting a further evaluation of the drilling fluid toxicity test. This study will estimate intra- and inter-laboratory variability in the test results. It will also assess differences in intra- and inter-laboratory variation of estimated toxicity between a drilling mud and that same batch of drilling mud with oil added. The study will require each laboratory to conduct individual range-finding tests and to calculate LC50's. An intra-laboratory variability analysis will be based upon data from laboratories with levels of experience ranging from some experience to highly experienced. The study will not include estimates of variability resulting from repeated measurements on different "batches" of the same mud since this information is not needed to evaluate the drilling fluid toxicity test.

B. Discharge of Oil in Water-Based Drilling Fluids

Water-based drilling fluids used in offshore drilling operations sometimes have oil, either diesel oil or mineral oil, added to them. Drilling fluids may also contain entrained formation hydrocarbons. (The discharge of oil-based drilling fluids would be prohibited under the proposed regulation).

Oil can be used to improve the lubricating properties of a water-based mud system and as an aid in freeing drill pipe that has become stuck downhole

during the drilling operation. Although diesel oil is often the most readily available oil at a drilling site, mineral oils have had a great deal of use recently for these purposes. When oil is used as an aid in freeing stuck drill pipe, a standard technique is to pump a slug or "pill" of oil or oil-based fluid down the drill string and "spot" it in the annulus area where the pipe is stuck. After use, the pill may be removed from the bulk mud system and disposed of separately. Even if the pill is recovered, residual oil from the pill can mix with the remainder of the mud system.

In recent years, research sponsored by both industry and government has shown that the presence of petroleum hydrocarbons in drilling fluid contributes significantly to its toxicity. Diesel oil is a complex mixture of petroleum hydrocarbons. It is known to be highly toxic to marine organisms and to contain toxic and nonconventional pollutants. There is evidence that diesel oil contributes significantly to the toxicity of drilling fluids that contain it. Toxicity data collected to date have shown that water-based muds containing diesel oil are substantially more toxic than muds without diesel. Mineral oil, which is available to serve the same operational requirements as diesel oil, has been shown to be a less toxic alternative to diesel oil. As a result, EPA has proposed a prohibition on the discharge of water-based drilling muds containing diesel oil and has encouraged the substitution of mineral oil for diesel oil.

The use of mineral oil instead of diesel oil as an additive in water-based drilling fluids will reduce the quantity of toxic and nonconventional organic pollutants that are present in a drilling fluid, as compared to the quantity of these pollutants present when using diesel oil as an additive. Mineral oils, with their lower aromatic hydrocarbon content and lower toxicity, contain lower concentrations of toxic pollutants than do diesel oils.

The proposed regulations would prohibit the discharge of diesel oil in detectable amounts in drilling fluid waste streams. The Agency selected the pollutant "diesel oil" as an "indicator" of the listed toxic pollutants present in diesel oil that are controlled through compliance with the effluent limitation, *i.e.*, no discharge. The technology basis for this limitation is product substitution of less toxic mineral oil for diesel oil.

As discussed in the preamble to the proposed regulations, the reason for prohibiting diesel discharges is to reduce the discharge of priority toxic and nonconventional organic pollutants

known to be present in diesel oils. The types and levels of these pollutants present in diesel oils have recently been documented in a study sponsored by the Offshore Operators Committee (OOC). The laboratory study was conducted to examine the chemical characteristics of selected diesel and mineral oils. The findings are presented in two comprehensive reports prepared by Battelle New England Marine Research Laboratory. These studies were made available to the Agency by the industry and are available in the rulemaking record.

Some typical methods for compliance with the diesel oil limitation are: (1) Use of product substitutes such as low toxicity mineral oils for spotting and lubricity purposes; and (2) use of diesel oil for spotting and/or lubricity purposes and transporting the used mud system to shore for proper treatment, disposal or reuse.

The industry commenters on the proposed regulations argued that diesel oil is the most effective agent for use in spotting fluids and that the use and discharge of diesel oil for this purpose should be allowed by the regulations. The industry attempted to demonstrate this preference for diesel oil in spotting fluids by providing EPA with the results of the industry-sponsored surveys discussed below. The industry also proposed to EPA that a program of limited duration be undertaken to determine the efficiency of recovering a diesel pill so that the discharge of diesel oil would be minimized, if not eliminated, when the used mud system is discharged to the ocean.

1. *American Petroleum Institute Drilling Fluids Survey.* In 1984 the American Petroleum Institute (API) conducted a survey among sixteen offshore oil operators in the Gulf of Mexico to obtain information on the use of diesel and mineral oils in water-based drilling fluids for the year 1983. Because the number of mineral oil applications in 1983 was small, API conducted a limited additional survey to obtain more data on experience with mineral oil pills in 1984.

These survey data presented by API indicate that mineral oil is more commonly used as a lubricant, while diesel oil is more commonly used for spotting purposes. Hydrocarbons (diesel or mineral oil) were added for lubricity to 12% of the 548 wells included in the survey. For 8% of the wells (44 wells), mineral oil was added, while for 4% of the wells (21 wells), diesel oil was added. For those drilling muds to which lubricity hydrocarbon was added, typically 3 percent (by volume) of the

mud formulation was composed of hydrocarbon additive.

2. *Offshore Operators Committee Spotting Fluid Survey.* Most industry representatives consider mineral oil to be adequate for use as a lubricity agent but believe diesel oil to be a superior material for freeing stuck pipe. In support of this position, industry has provided the Agency with the results of a retrospective survey comparing the success rates of diesel oil and mineral oil in freeing stuck pipe. This project was conducted in 1986 by the Offshore Operator's Committee (OOC) and covered the years 1983 to 1986.

The study examined information from 2,287 wells drilled in the Gulf of Mexico during that time period. Survey forms were distributed to operators who were asked to specify the number of wells drilled with water-based mud for each year covered by the survey and to supply certain information on each stuck pipe event where an oil-based spotting fluid was used. The API survey form asked for the data the event took place, the time interval between sticking and spotting activities, the depth at which the stuck pipe incident occurred, the based oil used in the spotting fluid, whether the hole was straight or directional, and whether the pill was successful in freeing the pipe.

Participants included twelve major oil companies and accounted for more than half of the offshore wells drilled during this period. Since some of these companies have more than one operating division, a total of sixteen survey response were received.

Of 2,287 wells surveyed that were drilled with water-based mud, 506 stuck pipe incidents were identified in which the operator chose to use an oil additive to attempt to free stuck pipe. Diesel oil pills were reportedly successful 52.7% of the time and mineral oil pills were successful 32.7% of the time in freeing stuck pipe, as shown in the following table:

OOC SPOTTING FLUID SURVEY RESULTS

Spotting fluid	Number incidents fluid used	Number incidents pipe freed	Success rate (percent)
Diesel	298	157	52.7
Mineral	208	68	32.7

Numerous other factors could impact the success of a pill in addition to the base oil. For example, Love (1983) determined that the chance of freeing stuck pipe in 113 documented cases and the potential success of such operations were related to specific conditions at

each well. Success decreased with increasing well angle, mud weight, amount of open hole, API fluid loss of the mud, and bottom-hole-assembly length. The chances of success dropped off substantially when a numeric index calculated from the above factors exceeded a certain level.

In addition to the above factors, Love found that pill additive packages (e.g., surfactants, emulsifiers, etc.), rheological properties of the mud, time until spotting, site-specific geological characteristics, and operator experience were likely to affect the success of a spotting operation.

The OOC examined four of these factors in their study: base oil, time until spotting, depth of spot, and type of well (straight or deviated). Results indicated that reducing the length of time until the spot was applied improved the chance of success dramatically for diesel pills. A similar but apparently less dramatic trend was observed for mineral oil pills. The diesel oil success rate was 61% if the pill was spotted in less than 5 hours. The rate dropped to 41% if the spotting time until spot exceeded 10 hours. The mineral oil success rate was 35% if the pill was spotting in less than 5 hours; the rate dropped to 31% if the time until the spot exceeded 10 hours.

Other factors examined by OOC appeared to have less impact on success for freeing stuck drill pipe. Both diesel and mineral oil showed higher success rates in straight rather than in directional or deviated wells, with diesel oil maintaining its reported edge over mineral oil by about the same percentage in each type of well. No trend was observed between depth of spot and success rates for diesel or mineral oil pills.

The OOC survey data showed that success rate with mineral oil pills varied considerably among operators. The data seemed to indicate that greater experience with mineral oil usage leads to considerably higher success rates than the reported average. The five operators that reported using mineral oil pills for more than 90% of their stuck pipe incidents experienced an average 42% success rate with such pills.

Some of the operators with greater mineral pill usage rates achieved extremely high success rates, which were comparable to the highest diesel pill success rates. The three highest success rates among operators using mineral pills were 58%, 60%, 75%. The three highest success rates among operators using diesel pills were 60%, 60%, and 64%.

Despite the industry's claim that diesel pills are more effective than

mineral pills, the study did show that mineral oil was used by operators in 41% of the stuck pipe incidents. Of the 506 incidents in the OOC study, 298 (or 59%) were treated with a diesel pill, while 208 (41%) were treated with a mineral pill. For some operators, mineral oil was the material of choice. Three operators (out of 16) used mineral pills exclusively. The Agency concludes that during the period of this study: (1) Mineral oil was in common use by operators in the Gulf of Mexico; (2) mineral oil is an available alternative to the use of diesel oil; and (3) success rates comparable to those with diesel oil can be achieved with mineral oil.

3. EPA/API Diesel Pill Monitoring Program (DPMP). In response to the proposed prohibition on the discharge of diesel oil, the industry requested that the discharge of diesel oil be allowed when diesel oil is the residual oil left in the bulk mud system following the use of a diesel pill and subsequent pill recovery techniques. Since neither the industry nor the Agency had sufficient information on the effectiveness of pill recovery, the Agency decided to participate with the industry in a test program to determine whether diesel oil can be effectively removed from a mud system after use of diesel-based pills.

In an effort to evaluate the effectiveness of diesel pill recovery techniques and to gather information on the extent to which any residual diesel oil contaminates the bulk mud system, EPA's Industrial Technology Division, EPA Regions IV and VI, and EPA's Environmental Research Laboratory in Gulf Breeze, FL conducted the Diesel Pill Monitoring Program (DPMP) in cooperation with the API. The program involved the collection and analysis of samples from active mud systems prior to use and after recovery of a diesel oil based pill.

a. DPMP Objectives. The objectives of the DPMP were to evaluate the efficiency of diesel pill recovery and to determine the effectiveness of the recovery practice by measuring the toxicity and diesel content of the mud system before and after pill recovery.

The major parameters used to establish the efficiency of diesel oil recovery included the toxicity and diesel content of muds both before and after a pill is spotted, the volume of material added and removed from the mud system (recovered pill and buffer material), the location and type of well being drilled, and the type and rheological properties of the mud and pill being used. This information was to be analyzed and used to determine the efficiency of diesel recovery and the

acceptability of the remainder of the mud system for discharge.

b. Program Description. The DPMP required an operator who used a diesel pill and intended to discharge the drilling muds to recover the diesel pill plus at least 50 barrels of mud that surfaced from downhole both before and after the pill, or as much as necessary until no visible oil was detected. The recovered pill and buffer material could not be discharged and had to be transported to shore for either disposal or reuse.

The federal waters of the Gulf of Mexico were chosen for this study because of the large number and diversity of drilling operations. The DPMP was implemented as part of the Agency's general NPDES permit for oil and gas operations in the Gulf of Mexico (Permit No. GMG 280000). The permit, which was published by EPA Regions IV and VI in the *Federal Register* on July 9, 1986 (51 FR 24897), prohibited the discharge of water-based drilling muds containing diesel oil unless: (1) The diesel oil was added only for the purpose of attempting to free stuck pipe, (2) the diesel pill and contaminated mud (buffer) were recovered and not discharged, and (3) the permittee participated in and complied with the written instructions of the DPMP. The program officially started in July 1986 with the issuance of the general permit, but some operators began participating in November 1985. The program ended as part of the permit requirement on September 30, 1987.

Some permittees elected not to participate in the DPMP on a well-by-well basis. If a permittee used a diesel pill and did not participate in the program, then all waste mud and cuttings generated after introduction of the pill were to be transported to shore for disposal, as required by the general permit. If permittees used a mineral oil or non-hydrocarbon based pill instead of diesel oil to free stuck pipe, then they were allowed to discharge waste mud and cuttings without participating in the DPMP, provided that all other permit conditions (e.g., toxicity limitation, no discharge of free oil) were met.

For those operators that did participate in the program, the DPMP established conditions for pill recovery, toxicity and chemical testing, and monitoring to generate data on the effectiveness of current recovery techniques. DPMP participants were required to meet all permit limitations with the exception of the prohibition on the discharge of diesel oil. Discharge of mud containing diesel oil was allowed if used only for freeing stuck pipe and if

provisions of the DPMP were followed. Also, for permit purposes, compliance with the toxicity limitation was demonstrated by sampling the mud just prior to the introduction of the pill. The end-of-well toxicity test was also conducted, but was used by EPA for information only, and not to determine compliance with the permit.

The procedures for conducting the sampling and analysis program are documented in a program manual that contains detailed instructions for all participants. The program manual is included in the record for this rulemaking.

The DPMP was managed by an Oversight Committee with members representing EPA's Industrial Technology Division and Regional Offices, EPA's Environmental Research Laboratory, the Natural Resources Defense Council, and API's Committee on Environmental Conservation. The Oversight Committee carried out the planning and development of the DPMP, met periodically to review laboratory activities and the information being gathered and analyses being performed, monitor the progress of the investigations, amend certain pill recovery techniques and sampling/analytical procedures, and issue a final report on the findings and conclusion of the DPMP.

EPA's Environmental Research Laboratory, Office of Research and Development, in Gulf Breeze, FL acted as the quality review laboratory for the toxicity testing part of this program. The Gulf Breeze Lab has been conducting research activities since 1976 to evaluate the potential impact of drilling fluids on the marine environment. The lab is experienced in handling and testing drilling fluid samples, and was involved in developing the protocol for the proposed Drilling Fluids Toxicity Test method (50 FR 34631). Thus, the Gulf Breeze Lab reviewed toxicity analyses generated during the DPMP, advised on data quality, and conducted analyses on duplicate samples.

The participating drilling operators were required to conduct sampling activities with prepackaged sampling kits whenever a diesel pill was used to free stuck pipe. Samples were taken of the pill, the diesel oil used to formulate the pill, and the active mud system before spotting and after the pill was recovered. Samples were shipped to a designated Central Control Laboratory (CCL) which was responsible for managing the flow of samples, analyses, and information. The CCL monitored the performance of contract laboratories and transmitted results to permittees

and to EPA's Sample Control Center (SCC).

The SCC is an Agency contractor that assists the Industrial Technology Division with the tracking of samples, assignment and performance evaluation of analytical laboratories, and the compilation of analytical results for Division projects. Thus, the SCC was assigned the task of monitoring the status of the DPMP for the Agency. The SCC was also responsible for maintaining a computerized data management system for all analytical information gathered during this program for Agency access and recordkeeping purposes, and for preparing quarterly data compilations to the Oversight Committee.

c. Diesel Pill Monitoring Program Findings. The Agency has performed analyses of the diesel pill program information received to date. This encompasses information on 119 stuck pipe incidents that occurred from November 1985 through September 1987. The Agency focused on analyses that would indicate the amount of diesel oil recovered (*i.e.*, removed from the bulk drilling fluid system) based upon known amounts introduced with the diesel pill formulation.

The Agency first examined the amount of diesel oil remaining in the bulk mud system after pill recovery and its relationship to the size of the buffer that was removed with the pill. According to the design of the pill recovery technique, it was expected that an increase in buffer size would result in higher diesel recover (*i.e.*, lower amounts of diesel oil remaining in the bulk mud system).

Diesel oil recovery was determined as the difference between the amount of diesel oil reportedly added to the mud system and the amount measured in the active system after two complete revolutions of the mud system following pill recovery. The results of the analyses indicate that, for the time period after the general NPDES permit for the Gulf of Mexico became effective in July 1986, the median diesel oil recovery level was about 80 percent. The amount of diesel oil remaining in the bulk mud systems ranged from less than one percent to more than 95 percent of the volume added, with a median level of almost 20 percent.

The amount of diesel oil remaining in the system did not appear to correlate with buffer size. Increasing the amount of buffer material collected had little effect on the median recovery level.

Next, the Agency evaluated DPMP data to determine if there were correlations between measured diesel oil content and the acute toxicity (LC50)

of drilling fluids. The Agency found that a distinct and rather dramatic relationship does exist. At low diesel concentrations, acute toxicity was found to increase rapidly with increasing diesel content. The data clearly support previous findings that diesel oil is a major contributor to mud toxicity. The finding that the acute toxicity of drilling fluids is heavily influenced by the amount of diesel oil present supports the Agency's original proposal to prohibit the discharge of diesel oil in drilling wastes.

The success rates for freeing stuck pipe for the DPMP and the OOC Spotting Fluid Survey (see previous discussion) were compared. The diesel pill success rate from the DPMP was found to be 36 percent. This value was derived by considering all stuck pipe incidents that occurred during the DPMP, which included multiple pills for some sticking incidents and multiple sticking incidents for some wells. The industry analysis of the OOC survey data included consideration of multiple stuck pipe incidents per well but success rates were calculated by considering only the first pill per sticking incident.

The Agency recalculated the diesel pill success rate from the DPMP on the same basis used by OOC in its survey. The resultant value is only a 40 percent diesel oil success rate, compared to the reported 52.7 percent diesel oil success rate from the OOC survey. It is not clear why the reported diesel pill success rates differ between these two studies. The DPMP data cast doubt upon the industry position regarding superiority of diesel oil over mineral oil in freeing stuck pipe.

It should be noted that during the course of the DPMP the use of mineral oil pills for freeing stuck pipe in the Gulf of Mexico reportedly declined. Industry has stated that the DPMP became a disincentive for the use and further development of mineral oil pills. However, industry representatives have noted that onsite recovery techniques would be essentially the same for pills formulated with either diesel or mineral oil.

Total costs for operators participating in the DPMP and transporting and disposing of the pill and buffer material onshore were reported to average about \$11,000 per spotting episode. Of that total, the costs of transporting the recovered pill and buffer from the rig to the disposal site, cleaning tanks, and landfilling the waste material averaged approximately \$8,000 per episode.

d. Conclusions on the Diesel Pill Monitoring Program. Based on analyses to date of information generated during the DPMP, the Agency believes that use

of the pill recovery techniques implemented during the program does not result in recovery of sufficient amounts of the diesel pill and reduction of mud toxicity to acceptable levels for discharge of bulk mud systems. Mud systems for approximately one-half of all wells in the DPMP contained residual diesel levels between one and five percent by weight after introduction of a diesel pill and subsequent pill recovery efforts. In addition, mud systems for approximately 80 percent of the DPMP wells failed the proposed 30,000 ppm LC50 limitation after pill recovery. Almost half that number (40 percent of the total) of the DPMP wells had water-based mud systems that contained residual diesel following pill recovery and showed LC50 values of less than (more toxic than) 5,000 ppm.

4. Conclusion on the Discharge of Diesel Oil. For the reasons discussed above, the Agency believes that its proposed prohibition on the discharge of diesel oil in detectable amounts is appropriate for the BAT and NSPS levels of control. The technology basis for the prohibition on the discharge of detectable amounts of diesel oil in drilling fluids and drill cuttings is substitution of mineral oil for diesel oil and lubricity and spotting purposes. Alternatively, where offshore operators choose to use diesel oil in a mud system, many operators have the option to transport used mud systems and associated cuttings to shore for proper treatment or disposal.

In comments submitted to the Agency on the August 26, 1985 proposed regulations, the American Petroleum Institute stated its agreement with EPA that satisfactory mineral oil substitutes are available for general mud lubricity applications, and that use of diesel oil for this purpose should be discontinued. API also maintained that, for use as a spotting fluid to free stuck drill pipe, mineral oil substitutes are not as effective as diesel in all cases. However, results of the surveys presented in this notice indicate that mineral oil additives are available, are being used by offshore operators, and are capable of being as effective as diesel in spotting fluid applications.

The Agency solicits comments on all aspects of this discussion and the studies used by the Agency to reconsider the proposed diesel discharge prohibition. The Agency also solicits any additional relevant data on this issue. The Agency will consider these data in the formulation of the final effluent limitations and standards for drilling fluids and drill cuttings.

C. Analytical Method for Diesel Oil Detection

The August 26, 1985 Federal Register notice proposed a method for detecting the presence of diesel oil in drilling fluids and drill cuttings waste streams. The method, based on retort distillation and gas chromatography, has subsequently been modified based on experience gained during the conduct of the Diesel Pill Monitoring Program. The current version of Proposed Method 1851, "Oil Content and Diesel Oil in Drilling Muds and Drill Cuttings by Retort Gravimetry and GCFID" is presented in Appendix A of this notice for review and comment.

This method for determining the identity and concentration of diesel oil in drilling wastes has an estimated detection limit of 100 mg/kg. Data on the precision and accuracy of the method have been generated and are included in the record for this rulemaking.

Today's modified version of the diesel analytical method also includes a proposed method for determining the oil content of drilling wastes. Discussion on the Agency's intended use of oil content determinations is presented in Part 2 of today's notice.

D. Metals Limitations

The proposed BAT and NSPS regulations would limit the levels of mercury and cadmium that could be present in discharged drilling fluids. The primary source of these toxic metals is the barite component of drilling fluids. The August 26, 1985 proposal included proposed effluent limitations of 1 mg/kg each of mercury and cadmium in the whole drilling fluid on a dry weight basis. The proposed effluent limitations would be maximum values (no single analysis to exceed).

Upon review and consideration of the comments and additional information received on this aspect of the proposed regulations, the Agency is considering different BAT and NSPS effluent limitations for control of mercury and cadmium levels in drilling fluids. The limitations being considered are 1.5 mg/kg of mercury and 2.5 mg/kg of cadmium in the whole drilling fluid on a dry weight basis. These effluent limitations also would be maximum (no single sample to exceed) values.

At proposal, the Agency estimated that mercury and cadmium limitations of 1 mg/kg each would result in a price increase of about 15% for barite. Industry commenters argued that the proposed mercury and cadmium limitations would result in a 65% increase in the price of barite that contains mercury and cadmium at

sufficiently low levels to allow for compliance with the effluent limitations. The price increase would be due to increased demand for such "clean" barite and additional costs in segregating and transporting supplies of clean barite for offshore use. It was suggested that there also may be a question about adequate sources and stocks of such "clean" barite for use in offshore drilling. Industry commenters indicated that sufficient supplies of barite containing no more than 3 mg/kg mercury and 5 mg/kg cadmium are available for offshore use. The Agency's analysis of industry-supplied data indicates that there should be no price increase for barite if barite containing mercury and cadmium at levels no higher than 3 mg/kg and 5 mg/kg, respectively, could be used to formulate drilling fluids.

The 1.5 mg/kg mercury and 2.5 mg/kg cadmium effluent limitations being considered by the Agency are end of pipe limitations based upon the use in drilling fluids of: (1) Barite containing no more than 3 mg/kg mercury and 5 mg/kg cadmium and (2) a typical barite content in drilling fluid of 50% barite by weight. If the barite content in the whole drilling fluid is 50%, the concentration of each metal in the whole drilling fluid would be about one-half of its concentration in the stock barite.

The Agency may establish the final BAT and NSPS effluent limitations equal to 1 mg/kg each of mercury and cadmium in the whole drilling fluid or equal to 1.5 mg/kg of mercury and 2.5 mg/kg of cadmium in the whole drilling fluid. The Agency may also establish the limitations at levels in the whole drilling fluid that the Agency determines more accurately reflect the use of barite containing no more than 3 mg/kg of mercury and 5 mg/kg of cadmium. The Agency believes that either set of effluent limitations under consideration for mercury and cadmium in whole drilling fluid is potentially appropriate for the BAT and NSPS levels of control and that either set of limitations is economically achievable.

The Agency solicits comment on all aspects of the mercury and cadmium limitations discussed here. In particular, the Agency solicits: (1) Data relating to the availability of adequate supplies of barite which will provide for compliance with particular metals limitations in discharged drilling fluids; (2) information about the appropriateness of its tentative conclusion that the use in drilling fluids of barite containing no more than 3 mg/kg mercury of 5 mg/kg cadmium correlates properly with end of pipe limitations of 1.5 mg/kg for mercury and 2.5 mg/kg for cadmium at the BAT

and NSPS levels of control (this includes data on the amounts and proportions of the barite component used in actual drilling fluid formulations, the proportion of drilling fluid systems and volumes of actual drilling fluids that contain barite in greater or lesser proportions than the estimate of 50% by weight that was used for the Agency's analysis, and data that would aid in the assessment of the changing proportion of the barite component of drilling fluid systems as the drilling fluid composition is modified during the drilling of a well); and (3) data that would aid in discerning differences in environmental effects between the effluent limitations under consideration.

III. Changes to Costing Data and Assumptions for Estimates of Economic Impacts

The Agency has re-costed compliance with the proposed regulatory option for drilling fluids and drill cuttings based upon additional technical and cost information provided in comments on the proposed regulation and additional information collected by the Agency since proposal. The Agency selected the year 1986 as the basis for presentation of the regulatory costs and economic analysis discussed in this notice because 1986 is the latest year for which sufficient actual costs and economic data are available.

The following discussion summarizes the major and most of the minor changes to costing items and assumptions used in developing aggregate industry compliance costs. The revised compliance costs were then used to perform a revised economic impact analysis of the amended regulatory approach presented in this section. The revised economic impact analysis is included in the rulemaking record. A summary of the economic impact analysis is presented in Section IV of this part of today's notice. The Agency solicits comment on these changes to the costing data and assumptions and on the revised economic impact analysis.

A. Toxicity Failure Rate for Water-Based Drilling Fluids

The Agency has undertaken an analysis of data on water-based drilling fluids collected by both EPA and the industry over the past two years to estimate failure rates of the proposed toxicity limitation (30,000 ppm, suspended particulate phase basis) in order to better estimate the aggregate industry compliance costs of the proposed regulatory option. These data include measured oil content and acute toxicity of field (used) muds.

The Agency has categorized the information by "data set". The data sets are identified as follows: The first data set is field mud data collected by API and presented to EPA in comments on the August 26, 1985 proposed regulations ("API 1"). The second data set is an extension of data collection by API subsequent to API 1 and submitted to the Agency in October 1986 ("API 2"). The third data set includes mud properties data, well identification information, and analytical results for field muds collected during the Diesel Pill Monitoring Program ("DPMP") from November 1985 through September 1987. The fourth data set is field mud information generated by the industry and submitted to EPA Region VI for the alternative toxicity request ("ATR") program under the NPDES permit for oil and gas operations in federal waters of the Gulf of Mexico (Permit No. GMG 280000). The fifth set of data is discharge monitoring report ("DMR") data that are being provided to EPA Region VI by the industry under the terms of the NPDES general permit for oil and gas operations in federal waters of the Gulf of Mexico.

Mud data were grouped to represent three segments of the total population of wells employing water-based mud systems. The segments included mud systems with no added oil, oil added for lubricity, and oil added for spotting purposes. Expected failure rates at the proposed LC50 limitation of 30,000 ppm were estimated for each of the three segments and thus for the total well population. Compliance costs were then estimated based on product substitution and transport of muds to shore for disposal.

Depending upon the individual data sets or combinations of data sets used to estimate toxicity failure rates based upon measured oil content, the toxicity failure rate for water-based drilling fluids which contain no added oil (original formulation, no reported lubricity or spotting fluids) range from approximately 2% to 15%. That is, between 2% and 15% of those water-based drilling fluid systems that do not contain added oil may be expected to fail the proposed toxicity limitation of 30,000 ppm SPP. If the toxicity failure rate were closer to 15% than to 2%, the industry would incur considerably higher costs for compliance with the toxicity limitation than the Agency had originally estimated. This factor, in conjunction with certain other costing elements discussed below, can add significantly to the aggregate industry compliance cost for the proposed effluent limitations.

The majority of water-based drilling fluid systems used in the Gulf of Mexico do not contain added oil. Results of the API Drilling Fluid Survey and the OOC Spotting Fluid Survey discussed previously support this conclusion. Reportedly, 88% of wells using water-based muds do not use oil for lubricity (API, 1983 data). Similarly, 78% of such wells do not use oil for spotting purposes (API, 1983-86 data). Therefore, assuming that the number of new wells that will not use oil for lubricity or spotting purposes will be uniformly distributed, a minimum of 69% ($88\% \times 78\%$) of all water-based drilling fluid systems will contain no added oil. Assuming 978 new offshore wells are drilled each year (see "Annual Rate of Development", below), between 13 wells ($2\% \times 69\% \times 978$) and 101 wells ($15\% \times 69\% \times 978$) drilled each year using water-based muds with no added oil may fail the proposed 30,000 ppm SPP toxicity limitation. Thus, as shown on Table 2 in Section IV of this part, the estimated annual industry cost of complying with only the proposed toxicity limitation of 30,000 ppm SPP varies from \$22 million to \$48 million (1986 dollars) depending on the estimated toxicity failure rate of water-based muds to which no oil has been added.

B. Annual Rate of Development

The costing and economic analyses for the proposed regulation were based upon an annual average of 1186 offshore wells drilled per year through the year 2000. The revised costing and economics are based upon an annual average of 978 wells drilled per year through the year 2000. The revised estimate is based upon updated projections of offshore oil and gas activity developed by the Department of Interior's Minerals Management Service (MMS). MMS has published 30-year forecasts of Outer Continental Shelf oil and gas production for major regions: the Atlantic, Gulf of Mexico, Pacific, and Alaska. These projections improve upon the Department of Energy/Energy Administration forecasts used by EPA at proposal for reasons outlined in Section IV of this part of today's notice.

C. Model Well Characteristics

Model well characteristics were established for the purpose of estimating compliance costs for the regulatory approaches under consideration. The assumed characteristics of a model 10,000 foot well in the Gulf of Mexico are discussed in Part 2 of this notice and are summarized below.

Drilling a typical 10,000 foot well is assumed to take 35 calendar days with

20 days of actual drilling time. The volumes of drilling fluid and drill cuttings discharges from a 10,000 foot model well are estimated to be 6,749 and 1,430 barrels, respectively. Water-based drilling fluids with oil added for lubricity plus spotting purposes are assumed to contain 5% oil by volume. Untreated drill cuttings associated with oil-based drilling fluids are assumed to contain 20% oil by weight. Drill cuttings associated with water-based drilling fluids to which oil has been added are assumed to contain 1% oil by weight.

There are two major refinements to the model well characteristics used for evaluating the proposed regulation and those used for the revised estimates presented in today's notice. They are: (1) An additional bulk mud discharge of 1,400 barrels to account for the active mud system at the end of a drilling campaign; and (2) an assumption of 1% instead of 10% oil content (weight basis) in cuttings associated with the use of water-based muds to which oil has been added.

D. Transportation and Disposal

For drilling wastes that do not comply with the proposed effluent limitations, the method of disposal at proposal and now is assumed to be transport of the wastes to shore by vessel for reconditioning and reuse (oil muds) or land disposal (cuttings and water-based muds). Model cost scenarios for transport and disposal were based on information provided by industry sources, as presented in Part 2 of this notice. These costs include rental of supply boats at \$3,000 per day, and revised costs for material containers, labor for loading, and unloading, transport, and landfill disposal at \$6.50 per barrel of mud and \$6.00 per barrel of cuttings.

The number or proportion of all water-based drilling fluid systems and associated cuttings that would have to be disposed of in this manner was reestimated. The estimate used for the proposed regulation was that 10% of all muds and cuttings would have to be transported to shore for disposal due to failure of one or more of the proposed effluent limitations. Revised estimates range up to 23% of all water-based muds and about 3% of all associated cuttings being transported to shore for disposal. (For oil-based muds and associated cuttings, there is no change from the 1985 proposed requirement that all such wastes would have to be transported to shore for disposal.)

E. Use of Oil-Based and Water-Based Drilling Fluids

The original and revised costing approaches assume the use of a water-based mud system in all wells down to the 10,000 foot model well depth. Oil-based muds may be used for the more difficult drilling situations (e.g., deviated holes at greater depths) to improve lubricity, thereby reducing torque and increasing the rate of penetration, to improve temperature stability of the mud system, and to reduce the chances of stuck drill pipe. Oil-based muds are also used in specific geologies like shale to preclude distortion of the formation strata that could occur through the absorption of water from water-based muds. API data for 1984 indicate that the average depth of all wells drilled deeper than the model well was 14,000 feet. It was assumed for recosting purposes that oil-based muds would be used below 10,000 feet. Of all the wells accounted for in the 1984 API data base, 30.8% were deeper than 10,000 feet and were assumed to have used oil-based muds at the depth interval 10,000 to 14,000 feet.

F. Cost Differential Between Diesel and Mineral Oils

The cost of substituting mineral oil for diesel oil was established at the time of the proposed regulation at \$2.10 per gallon. This differential cost included the increase in delivered purchase price of the mineral oil over diesel oil and the costs to provide and maintain separate onsite storage facilities for the mineral oil. Revised estimates presented in

today's notice include a differential cost of \$2.00 per gallon for calculations involving mineral oil substitution.

G. Pollutant Reduction Estimates

The issue of pollutant reduction does not directly affect the aggregate costing of the amended regulatory approach. However, pollutant reduction estimates are used in determining benefits and are used in evaluating the cost-effectiveness of the various regulatory options. The revised analysis presented in this part incorporates estimates of the reductions of specific pollutants (identified below) that would be achieved for each of the candidate regulatory approaches presented in this part of today's notice.

Determinations of the priority pollutant organics and nonconventional organics content of diesel oil and mineral oil mud additives were made in laboratory research sponsored by the industry. These data were used by the Agency to estimate potential reductions in the direct discharge of benzene, naphthalene, fluorene, phenanthrene, phenol and their alkylated homologues. Discharge reduction estimates were also made for mercury, cadmium, and several other metallic priority pollutants found in drilling fluids and associated drill cuttings.

H. Failure Rate for "No Discharge of Free Oil" Limitation (Static Sheen Test)

The approach followed by the Agency to re-cost compliance with the proposed regulation included consideration of expected failure rates for the static sheen test. As previously noted, the total

population of wells employing water-based mud systems were grouped into three classes: muds with no added oil, muds with oil added for lubricity, and muds with oil added for spotting purposes. The percentage of wells with discharges that would be likely to comply with the "no discharge of free oil" limitation based on the static sheen test were estimated for each of the three classes considered. Compliance costs were then determined based on transporting the wastes to shore for land disposal.

I. Monitoring Costs

The cost of monitoring for compliance with effluent limitations is considered to be an element of the total costs of compliance with the regulation. The preamble to the proposed regulations contained a "suggested" or "typical" monitoring frequency and analytical cost for each pollutant and waste stream subject to the regulation for a facility where both development and production operations are being performed. As such, the total monitoring costs presented were considered to be conservatively high.

Changes were made to the monitoring frequencies and analytical costs presented in the August 26, 1985 proposal for the muds and cuttings waste streams. These changes involved the monitoring frequency of the static sheen test and the addition of the diesel detection analysis. A summary of suggested sampling frequencies and estimated self-monitoring costs for muds and cuttings on a per well basis follows:

SUGGESTED SELF-MONITORING FREQUENCIES AND ESTIMATED ANALYTICAL COSTS

Waste stream per well(a)	Analysis	Cost per sample for analysis and labor (dollar)	Suggested minimum sampling frequency	Cost per well (dollar)
Drill Fluids (water-based).....	Bioassay (LC50).....	1,000	1/mo.(b).....	2,000
	Mercury, total.....	50	1/mo.(b).....	100
	Cadmium, total.....	50	1/mo.(b).....	100
	Diesel Detection.....	75	(b).....	150
Drill Cuttings (from water-based drilling fluids).....	Static Sheen.....	25	(c).....	250
	Static Sheen.....	25	(d).....	500
Total cost per well.....				\$3,100

(a) Assumed drilling campaign of 35 calendar days with 20 days of actual drilling time.

(b) Twice per well.

(c) Each day of discharge (assumed every 2nd day of drilling).

(d) Each day of drilling.

IV. Revised Industry Profile and Economic Analysis

A. Industry Profile

Since the proposal of August 26, 1985 (50 FR 34592), the Agency has updated the forecast of offshore oil and gas activity. This updated forecast replaces the projections developed for the proposal and presented in EPA's report titled "Economic Impact Analysis of

Proposed Effluent Limitations and Standards for the Offshore Oil and Gas Industry", EPA 440/2-85-003, July 1985. Those projections were based upon a 1984 Department of Energy/Energy Information Administration (DOE/EIA) production forecast.

The Agency's revised projections are presented in the Economic Impact Analysis for this notice which is

available in the record for this rulemaking. The revised projections are in response to recent changes in world oil prices and to the comments on the proposed regulations made by the Offshore Operators Committee (OOC) in February of 1986. The new Outer Continental Shelf (OCS) forecast has been developed using Department of Interior/Minerals Management Service (DOI/MMS) sophisticated production projections. Three alternative oil price scenarios have been analyzed: one at \$32, one at \$21, and one at \$15 per barrel of oil.

EPA's updated projections of OCS offshore oil and gas activity rely on the 30-year forecasts of oil and gas production developed by the Minerals Management Service. MMS developed its forecast based upon the data used in MMS' Environmental Impact Statement for the Proposed 5-year Outer Continental Shelf Oil and Gas Leasing Program (1987-1992), MMS 86-0127. In that report, MMS estimated "conditional resources" for 21 OCS regions, assuming a market value of \$32 per barrel of oil (1986 dollars). These conditional resources represent the mean amount of oil and gas reserves that are economically recoverable from the leased areas, given that exploration confirms the presence of hydrocarbon reserves. The probability of finding reserves varies from region to region. An estimate of the expected resources to be developed in each leased area can be obtained by multiplying the probability of finding reserves (estimated by MMS) by the conditional resource estimates. Using this resource estimate, and rules-of-thumb regarding the amount of time it takes to develop the resources in each area, MMS has developed a schedule of resource production for the 1987-1992 lease sales.

To develop the full 30-year projections, MMS used its estimates of the percentage of undeveloped resources to be leased during each of its subsequent leasing periods. For example, if 25 percent of Alaska's resources are expected to be leased in 1987-1992, and 25 percent of Alaska's resources are expected to be leased in 1992-1996, then the resource projections for the 1992-1996 lease would replicate the resource projections for the 1987-1992 lease, with a 5-year lag. If 50 percent of Alaska's resources were to be leased in 1992-1996, then the projections would be double those for the 1987-1992 lease, with a 5-year lag.

Based on this methodology, MMS has published 30-year projections of OCS oil and gas production for four major regions: the Atlantic, Gulf of Mexico,

Pacific, and Alaska. These projections improve upon the DOE/EIA forecast used by EPA at proposal for the following reasons. First, the MMS forecast is based on a disaggregated analysis of resource potential and lease activity in each of the four regions. Second, the DOE/EIA forecast did not extend beyond 1995 while the MMS forecast extends to 2015; thus the MMS forecast increases the accuracy of the Agency's projections to 2000. Finally, the MMS forecast is easily amenable to different price scenarios. In its "Secretarial Issue Document" (1987), MMS developed alternative leasable resource estimates for various prices. Based on these resource estimates, the ratio of resources at \$21 per barrel to \$32 per barrel, and \$15 to \$32 per barrel are as follows:

Region	Ratio of \$21/bbl to \$32/bbl	Ratio of \$15/bbl to \$32/bbl
Gulf.....	0.965	0.858
Pacific.....	0.790	0.541
Atlantic.....	0.514	0.327
Alaska.....	0.098	0.0

These ratios mean, for example, that using the MMS resource estimates for the Pacific OCS at \$32 per barrel as the basis (*i.e.*, MMS projections at \$32 per barrel equal 100 percent), the Agency estimates that 79 percent of these Pacific resources would be developed if the price of oil fell to \$21 per barrel. Similarly, if the price fell from \$32 to \$15 per barrel, the Agency projects that it would make economic sense for the oil and gas industry to develop 54.1 percent of those Pacific resources. These ratios were used to develop the two alternative forecasts from the \$32 per barrel forecast.

The Agency has also developed new projections for the number of wells drilled in state offshore waters and the number and configuration of offshore platforms. The revised estimates reflect the declining role of state waters in oil and gas drilling in the Gulf of Mexico. (Between 1967 and 1985 the state-to-federal ratio dropped about 30 percent every seven years.) Drilling in the state waters of the Gulf of Mexico is projected to be 11 percent of federal production for the period 1986-1992 and 8 percent for the period 1993-2000. No state water activity is projected in the Atlantic. Based upon drilling activity in state waters between 1980 and 1985, drilling in state waters is projected to be 50 percent of the activity in federal waters in the Pacific and 300 percent of federal activity in Alaska.

In the following discussion of the economic impacts of the regulation, only the results of the Agency's analysis based on an average oil price for the years 1986-2000 of \$21 per barrel are presented. At this price, an average of 978 wells are projected to be drilled each year. (If the average price of oil is \$15 per barrel between now and the year 2000, 807 wells are projected to be drilled each year; if the oil price is \$32 per barrel, 1,178 wells would be drilled.)

B. Economic Impacts

At proposal, the Agency estimated the total annual cost of the selected drilling fluids and cuttings option at \$36.7 million (in 1986 dollars). Table 1 presents the Agency's revised estimate of the cost of the proposed regulations for drilling fluids and cuttings which now totals \$76.6 million annually. The annual estimated cost of controlling drilling fluids has increased from \$27.7 million at proposal to \$71.1 million. The annual cost of controlling drill cuttings has decreased from \$9.1 million to \$5.5 million. The revised estimates for the proposed regulations have increased despite some declines in components of the estimate (*e.g.*, the number of wells drilled per year and the monitoring costs per well). The increase in the revised cost estimates for the proposed regulations is due primarily to increases in: (1) The percentage of the drilling fluids that would have to be transported to shore for disposal ("barged") and (2) the per-well cost of barging drilling fluids. Barging costs are incurred when these drilling fluids fail the limitation on toxicity or the prohibition on the discharge of free oil. As indicated in Table 1, the estimated percentage of drilling fluids that would fail effluent limitations and thus be barged has increased from 10 percent to 23 percent based upon revised estimates of effluent limitation failure rates discussed earlier in today's notice. The per-well cost of barging drilling fluids has increased primarily because the volume of the model well drilling fluid system was increased from about 5300 to about 6700 barrels as discussed earlier in Section III.

The Agency has identified four alternative approaches for controlling offshore drilling fluids and drill cuttings discharges. The term "approach" is used to refer to any one of four particular scenarios for costing purposes which are differentiated by:

(1) The differing toxicity failure rates for water-based drilling fluids to which no oil has been added, as presented in Section III.A. of this part of today's notice, and

(2) The differing sets of effluent limitations for mercury and cadmium is drilling fluids as presented in Section II.D. of this part of today's notice. The first approach, identified here as "Approach A" is the one that is most similar to the regulatory option proposed in 1985, but as explained above, that option has been recosted to incorporate comments the Agency has received and updated information the Agency has gathered since proposal in 1985. Approaches B, C, and D are variations on Approach A, reflecting the differences as explained in Section III above.

The four approaches are summarized below:

Approach	Assump- tions	Failure Toxicity		Total annual cost (\$00, 1986 dollars)
	Rate for water- based fluids (percent)	Limita- tions ^a for Hg & Cd		
A. ¹	15	1, 1		\$76,617
B.	2	1, 1		50,662
C.	15	1.5, 2.5		66,113
D.	2	1.5, 2.5		40,158

¹ Of the four approaches, Approach A is most similar to the 1985 proposed regulatory option.

^a 1, 1 means 1 mg/kg each mercury and cadmium in discharged drilling fluids; 1.5, 2.5 means 1.5 mg/kg mercury and 2.5 mg/kg cadmium in discharged drilling fluids.

As shown in the last column of the above table, the total annual costs for the four approaches range between \$40.2 million and \$76.6 million. Costs are given in 1986 dollars here and on Tables 1, 2, and 3 below because 1986 is the most recent year for which a consistent and complete set of data is available for use in the economic impact analysis model. (For reference, these total costs are estimated to range between \$42.0 million and \$80.1 million in 1988 dollars, if they are adjusted for inflation using the *Engineering News Record's* construction index for the first six months of 1988.)

The technology basis and the limitations of Approach A are similar to those of the proposed regulation. As shown on Table 2, the costs of controlling fluids are more for A than for B is based on the assumption that more drilling fluids pass the toxicity test, and thus, under Approach B, fewer wells incur the cost of barging.

Table 2 also shows that the costs of Approach C are less than the costs of Approach A (and the costs of D are less than the costs of B). Approaches A and

B cost more because they include limitations on the mercury and cadmium content of discharged drilling fluids at a maximum (no single sample to exceed) concentration of 1 mg/kg each on a dry weight basis in whole drilling fluid. This limitation is estimated to increase the cost of barite by 15 percent, due to increased costs for transporting and segregating "clean" barite for use in offshore drilling. The annual cost of this barite limitation is \$10.5 million (in 1986 dollars). Approaches C and D cost less because they contain less stringent limitations for mercury and cadmium. The 1.5 mg/kg mercury and 2.5 mg/kg cadmium limitations are estimated to be achievable at no additional cost, because they are based on the use of barite containing no more than 3 mg/kg of mercury and 5 mg/kg of cadmium. Thus, current supplies of barite for offshore drilling can meet these alternative limitations.

The estimated costs for approaches A, B, C, and D are all higher than the estimated cost of the proposal option. However, all four approaches presented in this notice are economically achievable. The Agency's economic impact notice are economically achievable. The Agency's economic impact analysis compares the cost of oil and gas drilling in the absence of any BAT/NSPS regulations (*i.e.*, the base case) to the cost of drilling with each of the regulatory approaches—A, B, C, and D. The results of this analysis are summarized in Table 3 for a 12-well, oil-only model platform in the Gulf of Mexico. Comparing compliance costs to the base case, drilling costs for a typical well would increase between 1.03 percent (for Approach D) to 1.95 percent (for Approach A). With the regulation, the net present value of a typical drilling project in the Gulf of Mexico would decline between 1.5 and 3.0 percent, and the cost of producing a barrel of oil would increase between four and eight cents. For a major oil company (which is the typical participant in offshore oil drilling projects), the debt incurred due to any of the four regulatory approaches represents only 0.01 percent of the company's net worth. As shown on Table 3, the cost of the regulation also has no appreciable impact on any of the financial ratios examined for these oil companies, including: the current ratio, the long term debt-to-equity ratio and the debt-to-capital ratio. The Agency's analysis shows that the economic impacts of the regulation are not substantial, and thus any of the

approaches presented in this notice are economically achievable.

C. Cost-Effectiveness

In addition to the foregoing analyses, the Agency has performed a cost-effectiveness analysis of the two levels of cadmium and mercury limitations presented in today's notice. Table 4A presents the cost-effectiveness of these two levels (Approaches A and C) based on the assumption of a toxicity failure rate of 15 percent for those water-based drilling fluids to which no oil has been added. Table 4B presents the cost-effectiveness of the same levels of limitations for cadmium and mercury but with a toxicity failure rate of 2 percent for those water-based drilling fluids to which no oil has been added (Approaches B and D).

According to the Agency's standard procedures for calculating cost-effectiveness, on each of the tables the approaches have been ranked in order of increasing pound-equivalents (PE) removed. The pound equivalents removed for each approach were calculated as the number of pounds of pollutants removed by implementing each approach weighted by the relative toxicity of those pollutants. The results of these calculations are shown in the second columns of Tables 4A and 4B. (The "Cost-Effectiveness Report," which is available in the record of this rulemaking, supports this presentation, describes the cost-effectiveness procedures in detail, and presents the toxic weights used for each approach.) Cost-effectiveness is calculated as the ratio of the incremental annual cost to the incremental pound equivalents removed by the levels of control shown in the tables. So that comparisons of the cost-effectiveness among industries may be made, the annual costs are converted to 1981 dollars.

The cost-effectiveness of the regulatory approaches is shown in the last column of Tables 4A and 4B below. All approaches are cost-effective:

Assuming a failure rate of 15 percent as shown on Table 4A, Approach C is \$69 and Approach A is \$19 per pound equivalent removed.

Assuming a failure rate of 2 percent as shown on Table 4B, Approach D is \$54 and Approach B is \$16 per pound equivalent removed.

These costs are well within the range of the cost-effectiveness of new source performance standards for other industries.

TABLE 1.—COSTS AND OTHER SIGNIFICANT PARAMETERS OF PROPOSAL OPTION AND OF COMPARABLE APPROACH A, DRILLING FLUIDS AND CUTTINGS

[1986 dollars]

Parameter	At proposal 1985 for selected option	Revised estimate for comparable approach A
Number of wells drilled annually.....	1,166	978
Average price of oil per barrel 1985/6 to 2000.....	\$32	\$21
Percent barged:		
Drilling fluids.....	10%	23%
Drilling cuttings.....	10%	17%

TABLE 1.—COSTS AND OTHER SIGNIFICANT PARAMETERS OF PROPOSAL OPTION AND OF COMPARABLE APPROACH A, DRILLING FLUIDS AND CUTTINGS—Continued

[1986 dollars]

Parameter	At proposal 1985 for selected option	Revised estimate for comparable approach A
Average cost of barging per well where barging is required:		
Fluids.....	\$113,000	\$251,000
Cuttings.....	\$69,000	\$73,000
Total barite costs.....	\$11,200,000	\$10,504,000
Monitoring costs per well.....	\$3,734	\$3,100

TABLE 1.—COSTS AND OTHER SIGNIFICANT PARAMETERS OF PROPOSAL OPTION AND OF COMPARABLE APPROACH A, DRILLING FLUIDS AND CUTTINGS—Continued

[1986 dollars]

Parameter	At proposal 1985 for selected option	Revised estimate for comparable approach A
Total annual costs:		
Fluids.....	\$27,664,000	\$71,140,000
Cuttings.....	\$9,072,000	\$5,477,000
Total.....	\$36,736,000	\$76,617,000

¹ Includes both cuttings associated with water-based fluids (about 3%) and cuttings associated with mineral-oil based fluids.

TABLE 2.—REGULATORY COST OF ALTERNATIVE POLLUTION CONTROL APPROACHES

[\$000, 1986 dollars]

Parameter	Alternative pollution control approaches			
	Approach A	Approach B	Approach C	Approach D
Drilling fluid costs.....	\$71,140	\$45,185	\$60,638	\$34,681
Clean barite.....	10,504	10,504	0	0
Mineral oil substitution for diesel oil.....	1,706	1,706	1,706	1,706
Static sheen test failure.....	8,288	8,288	8,288	8,288
Toxicity test failure.....	48,099	22,144	48,099	22,144
Monitoring costs.....	2,543	2,543	2,543	2,543
Drill cuttings costs.....	5,477	5,477	5,477	5,477
Static sheen test failure.....	1,735	1,735	1,735	1,735
No discharge with use of oil-based muds.....	3,253	3,253	3,253	3,253
Monitoring costs.....	489	489	489	489
Total annual costs ¹	76,617	50,662	66,113	40,158
Average costs per well drilled.....	78	52	68	41
Percent of drilling fluids barged.....	23.3%	12.5%	23.2%	12.5%
Percent of drill cuttings barged ²	6.7%	6.7%	6.7%	6.7%

¹ For 978 wells per year, based upon average oil price of \$21/bbl.

² Includes both cuttings associated with water-based fluids and cuttings associated with mineral oil-based fluids.

Source: EPA estimates.

TABLE 3.—ECONOMIC IMPACTS OF THE OFFSHORE OIL AND GAS REGULATION ON MUDS AND CUTTINGS, 1986-200 ^a

[Selected Parameters]

Approach ^b	Total annual cost of regulation	Change in drilling costs per well		Project Impacts; 12-well, oil-only platform in the Gulf of Mexico			Impacts for a typical major oil company ^f					
		Dollar thousand	Percent	Change in NPV w/Reg. vs. NPV w/o Reg.	Cost per barrel of oil ^c		Change in annual debt	Reg. debt compared to:		Current ratio ^d	Long term debt to equity ^e	Debt to capital ^e
					Percent	Dollar		Percent change	Total Assets			
				Dollar millions			Percent			Percent	Percent	Percent
A.....	76.6	78	1.95	-3.25	21.44	0.37	2.12	0.006	0.014	1.11	35.6	23.8
B.....	50.7	52	1.30	-2.15	21.41	0.23	1.408	0.004	0.009	1.11	35.6	23.8
C.....	66.1	68	1.70	-2.81	21.43	0.33	1.83	0.005	0.012	1.11	35.5	23.8
D.....	40.2	41	1.03	-1.71	21.40	0.19	1.11	0.003	0.007	1.11	35.6	23.8
Industry Average.....		\$4,000		\$18,239	\$21.36			\$35,893	\$15,314	1.11	35.5	23.8
Baseline.....		(\$000)		(\$000)				\$millions	\$ millions			

NPV - net present value.
Reg. - regulation.

^a 1986 dollars. Based on projected average oil price of \$21 per barrel and 978 wells drilled per year for the years 1986-2000.

^b Approach A is the proposed approach. It is costed assuming a 15% increase in barite costs to meet mercury and cadmium limitations in the discharged muds and a toxicity test failure rate of 15% for water-based muds with no oil added, Approach B is the same as A but assumes a toxicity test failure rate of 2%. Approach C is based on an alternative metals limitation in the stock barite and an assumed toxicity test failure rate of 15%. Approach D is the same as approach C except the toxicity failure rate is 2%. (See Section II and IV of the notice for details.)

^c Includes transfer payments such as lease payments, royalties, oil and gas taxes, corporate income taxes.

^d Current asset/current liabilities. Assume working capital financing.

^e Assumes debt financing.

TABLE 4 A—COST-EFFECTIVENESS FOR OFFSHORE OIL AND GAS, DRILLING FLUIDS AND CUTTINGS—RANKED BY ANNUAL POUND EQUIVALENTS (PE) REMOVED

[Assuming 15% failure rate] ¹

[1981 dollars] ²

Approach ³	Total annual		Incremental		Incremental cost effectiveness \$/PE (1981 \$)
	PE Removed	Cost (1981 \$) (\$000)	PE removed	Cost (1981 \$) (\$000)	
Current.....	0	0			
C.....	787,685	54,639	787,685	54,639	\$69
A.....	1,237,607	63,320	449,922	8,681	\$19

¹ As explained in the text above and in the cost-effectiveness analysis report which supports this notice, Approaches A and C assume a 15 percent toxicity failure rate for water-based drilling fluids to which no oil is added.

² Factor for converting costs in 1981 dollars to 1986 dollars is: 1.21 The cost-effectiveness is standardized in 1981 dollars to facilitate comparison among numerous regulated industries.

³ Approach A limits Hg and Cd to 1 mg/kg each in discharged drilling fluids. Approach C limits Hg to 1.5 mg/kg and Cd to 2.5 mg/kg in discharged drilling fluids.

TABLE 4 B—COST-EFFECTIVENESS FOR OFFSHORE OIL AND GAS, DRILLING FLUIDS AND CUTTINGS—RANKED BY ANNUAL POUND EQUIVALENTS (PE) REMOVED

[Assuming 2% failure rate] ¹

[1981 dollars] ²

Approach ³	Total annual		Incremental		Incremental cost effectiveness \$/PE (1981 \$)
	PE removed	Cost (1981 \$) (\$000)	PE removed	Cost (1981 \$) (\$000)	
Current.....	0	0			
D.....	610,939	33,188	610,939	33,188	\$54
B.....	1,167,850	41,869	556,911	8,681	\$16

¹ As explained in the text above and in the cost-effectiveness analysis report which supports this notice, Approaches B and D assume a 2 percent toxicity failure rate for water-based drilling fluids to which no oil is added.

² Factor for converting costs in 1981 dollars to 1986 dollars is: 1.21 The cost-effectiveness is standardized in 1981 dollars to facilitate comparison among numerous regulated industries.

³ Approach B limits Hg and Cd to 1 mg/kg each in discharged drilling fluids. Approach D limits Hg to 1.5 mg/kg and Cd to 2.5 mg/kg in discharged drilling fluids.

V. Environmental Assessment Information

A. Mercury and Cadmium in Barite and Environmental Consequences on Aquatic Life

Mercury and cadmium are two potentially toxic constituents of barite-containing drilling fluids. The potential environmental impacts of the discharges of these metals in drilling fluids have been investigated by the Agency (1).

Sediment mercury and cadmium concentrations resulting from barite-containing drilling fluid discharges were estimated and evaluated to determine environmentally significant sediment alterations. Specifically, the Agency's study:

- Assesses the degree to which sediment levels of mercury and cadmium may be altered at the local level (e.g., within a 500 m radius of the drilling facility);
- Assesses the degree to which sediment levels of mercury and cadmium may be altered at the regional

level for three cumulative discharge scenarios;

- Evaluates environmental consequences of sediment enrichment by mercury and cadmium with regard to what is known concerning the biological availability of these metals.

All modeled levels of mercury (1 and 3 ppm) and cadmium (1 and 5 ppm) in barite showed some increase in sediments within 500 meters of the model 58-well Gulf of Mexico platform (the model size facility selected for the environmental assessment). At low background sediment levels (0.01 ppm for mercury and 0.04 ppm for cadmium) and higher assumed levels of 3 ppm for mercury and 5 ppm for cadmium in barite, the average increase were in excess of 2000% (an increase of 20 times) for mercury over 800% (an increase of 8 times for cadmium. The average increases at the lower assumed levels of 1 ppm for mercury and cadmium in barite were over 600% and over 160%, respectively at low background sediment levels. At high background sediment levels (0.04 ppm for mercury

and 0.2 ppm for cadmium), the average increases in sediment were approximately 500% for mercury and 160% for cadmium at higher specified levels, and approximately 160% for mercury and 25% for cadmium at lower assumed levels (1 ppm each).

Because a large fraction of the drilling muds is expected to be transferred beyond the immediate vicinity of the platform, the cumulative impacts of multiple drilling were analyzed for three regional scenarios: the Santa Barbara Channel, a Louisiana continental shelf area, and the entire Louisiana Gulf of Mexico lease area.

The estimated increase in added barite concentrations at the sediment surface after 24 years would be 1524 ppm for the Santa Barbara Channel, 933 ppm for the Louisiana shelf area, and 272 ppm for the entire Louisiana lease area. Ther analysis assumes typical sediment mixing conditions, and that all solids stay within the regional areas modeled. At low background mercury and cadmium sediment levels (0.01 ppm

for mercury and 0.04 ppm for cadmium) and barite containing 3 ppm of mercury and 5 ppm of cadmium, the increases of mercury and cadmium in the Santa Barbara Channel sediments were estimated at 46% and 19% respectively. At high background sediment levels (0.04 ppm mercury and 0.2 ppm cadmium), the increases would be 11% and 4%, respectively. If barite controls 1 ppm of mercury and cadmium the projected regional increases are 15% and 4% respectively for low background sediment levels, and 3% for mercury and <1% for cadmium for high background sediment levels.

For the Louisiana shelf and the entire Louisiana offshore lease area the resulting projected regional increases for the same mercury and cadmium barite and background sediment levels were approximately $\frac{2}{3}$ and $\frac{1}{2}$ of the levels estimated for the Santa Barbara Channel due to lower estimated well density.

This analysis shows that barite could be a measurable source of mercury and cadmium near drilling platforms in sediments if present at the discharge levels used in this analysis, even if the sediment transport processes eventually remove some fraction of the barite from the shelf sediments and redeposit it in deeper offshore areas where the environmental impacts are expected to be less significant.

The comments received from the industry on the proposed regulation stated that the cadmium and mercury associated with drilling fluids are present as insoluble sulfides in barite and have a very low bioavailability to marine organisms.

The Agency recognizes that an incremental increase in sediment metals does not necessarily translate into a comparable increase of impacts on marine life. However, these data show that mercury and cadmium discharged with the barite containing drilling fluids have a potential to cause environmental problems in the marine environment and a potential for transport to humans through consumption of contaminated seafood, especially shellfish.

The environmental consequences of elevated local and regional concentrations of mercury and cadmium due to barite-containing drilling fluids are difficult to judge, because many aspects related to the environmental fate of these metals in marine environment are not well understood. An extensive literature review was carried out as part of this study on fate and effects of these metals on marine environments, especially with respect to bioavailability, bioaccumulation, and biomagnification in the food chain.

Based on the U.S. Congress, Office of Technology Assessment (OTA) Report (2), the ability of a metal to affect marine organisms depends primarily on its form (e.g., dissolved or particulate, bound to other substances or free), and this is greatly affected by site-specific conditions. In their particulate form, most metals tend to adsorb onto other particles that eventually settle from the water and are deposited as sediment. Once deposited in oxygen-poor sediments, the chemical form of these metals is generally stable. However, if the sediments are subsequently oxygenated, some metals, including cadmium, may dissolve and be slowly released into the water column, and may be taken up by non-benthic organisms. Sediments can be oxygenated (and also resuspended) by bioturbation, storms, and other disturbances. Metals also can be released as a result of other changes such as salinity fluctuation in estuaries. Microorganisms in sediments can modify the slightly toxic inorganic mercury and convert it to highly toxic and volatile methyl mercury.

OTA's report (2) identified a significant potential for transport of both mercury and cadmium to humans through consumption of contaminated seafood. Marine organisms can ingest metals that are dissolved in the water or they can ingest particulate matter onto which metals are adsorbed. Once ingested, some metals can pass through the gut and be excreted, while others cross the gut membrane and accumulate in organismal tissue. Both cadmium and mercury tend to bioaccumulate in marine organisms. Mercury in its methylated form is the only metal known to biomagnify in successive levels of the aquatic food chain. Even when bioaccumulation is not a factor, significant quantities of metals can concentrate in the gut and gills of marine organisms without actual absorption into the tissues. This is especially true for shellfish that filter large quantities of seawater and ingest solid matter during feeding (e.g., oysters, clams, mussels).

Because people generally eat these organisms in their entirety, toxic substances can be passed to humans even in the absence of bioaccumulation. This mechanism probably accounts for most instances of shellfish contamination involving metals that do not bioaccumulate.

Results of investigation of sources, fates, and effects of metals near municipal wastewater outfalls in southern California coastal waters indicate that: (1) The largest portion of metals entering the system is in particulate form, but a large portion may

be released into the dissolved phase upon mixing with seawater and may be carried out of the region by prevailing currents; (2) despite these losses of the solubilized fraction, the particulate and sediment concentrations of metals in the vicinity of municipal wastewater outfalls are highly elevated; (3) filter feeders (e.g., scallops, mussels) have exhibited higher metal levels near sources of contamination as compared to "control" areas; (4) there is evidence of bioaccumulation of metals in filter-feeding bivalves in the vicinity of marine outfalls; (5) concentrations of cadmium in muscle tissue of demersal fish tend to be less than in sediments, but the concentrations in the liver or hepatopancreas of animals could exceed that of the sediments.

Analysis conducted by Trefrey et al. (3), investigating trace metals in barite indicates that mercury is tightly bound in barite and not easily released. Cadmium, however, is more easily leached from the barite than many other metals.

None of the above data, however, provide conclusive evidence relative to the stability or bioavailability of mercury and cadmium in barite-containing drilling fluids. Work is currently underway within EPA and NOAA to define the equilibrium partitioning of metals in sediments, pore water, and organisms. Results of these efforts are expected to aid in the evaluation of potential impacts of mercury and cadmium and other metals in barite-containing drilling fluids on aquatic organisms. However, the partitioning of these metals from barite may be quite different from the partitioning from other discharges (e.g., sewage particles) or from ambient sediments.

As discussed in previous sections of this notice, the Agency has found that as the levels of mercury and cadmium in barite are decreased, the other toxic metals in barite are also found to generally decrease. Arsenic, lead, zinc and other toxic metals may also be released into the marine environment as a result of barite discharges. In addition, the levels of cadmium and mercury that can be expected to occur in sediments as a result of potential offshore drilling activities will be dependent on the level of drilling activity that will occur, the energetics of the region, and the background levels of these metals in the sediment. All of these factors will vary from one region of the country to another.

The Agency is continuing to evaluate the environmental fate of mercury, cadmium and other toxic metals

associated with barite to determine the impacts of these discharges in the marine environment. The Agency is, therefore, soliciting new information related to the occurrence, bioavailability, release, bioaccumulation, and other related data on mercury, cadmium and other toxic metals in barite and in drilling fluids.

B. Analysis of Shallow Water Dispersion Models

As part of the ongoing evaluation of potential impacts from offshore oil and gas discharges, discharge dispersion models were being examined as a component in an assessment of the fate and transport of drilling muds and produced water in the marine environment. For the most part, models have been applied to discharge situations in relatively deep waters (greater than 40 meters in depth); their appropriateness and reliability in more shallow waters (40 meters to mean high tide) is much less well known.

In addition to discharges occurring in the deeper waters of the Outer Continental Shelf (OCS), produced waters, drilling fluids, and other oil and gas discharges are released in a geographic zone that extends from the high tide line out to the OCS. In the Gulf of Mexico, where over 90% of all offshore production takes place, this geographic zone includes the offshore area extending 9 miles off the coast of Texas and 3 miles off the coast of Louisiana. Of all offshore wells drilled in State waters off the coasts of Texas and Louisiana, approximately 11% are in water depths of greater than 20 meters, some 43% are in water depths of 10 to 20 meters, and about 46% are in water depths of less than 10 meters.

Appropriate dispersion models for discharges occurring in these shallow waters need to be identified. In response to this need, the Agency has analyzed existing dispersion models to identify the limitations of their shallow water utility (4). Several potentially relevant dispersion models were identified and reviewed by the Agency to determine their applicability to shallow water, offshore oil and gas discharges (Table A). Of the models reviewed, some were rejected as not being appropriate for the type and/or methods of discharge or receiving waters. Although under other circumstances these models have utility, they were judged to have limited, general application with regard to shallow water marine discharges, oil and gas discharges, or the type of data presently available either for these areas or types of discharges.

The remaining models were divided into three categories and analyzed in

more detail. The first category includes models concentrating primarily on the fate of discharged solids. These models may also predict the fate of the liquid phase. However, in these models the liquid phase was considered as a secondary objective. The second category includes models that deal primarily with the liquid phase of discharges; often, these models address thermal effects. The third category includes models designed primarily to address discharges of toxics.

Table A. Models Reviewed for Shallow Water Dispersion Applicability

I. Models that were reviewed, but were not found relevant for these receiving water areas, discharge types, or available data:

DIFHD (Army Corps of Engineers, 1987)
 UPLUME and ULINE (EPA, 1985)
 DYNTOX (EPA, 1983)
 HSPF (EPA, 1985)
 MINTEQ (EPA, 1984)
 PRZM (EPA, 1984)
 QUAL2E and QUAL2E-UNCAS (EPA, 1987)
 SWMM (EPA, 1987).

II. Models that were reviewed and considered for further study:

Category 1: Primarily Solid Phase Models
 OFFSHORE OPERATORS COMMITTEE (OOC) MUD DISCHARGE MODEL (M.G. Brandsma et al., 1983)
 A TIME-DEPENDENT, TWO-DIMENSIONAL MODEL FOR PREDICTING THE DISTRIBUTION OF DRILLING MUDS DISCHARGED TO SHALLOW WATER (EPA-2D) (Yearsley, 1984)
 DIFID and DIFCD (Army Corps of Engineers, 1987)
 DRIFT MODEL (Runchal, 1983).

Category 2: Primarily Liquid Phase Models
 PDS MODEL (Pritch, Davis, and Shirazi, 1974)
 UOUTPLM, UMERGE, and UDKHDEN (EPA, 1985)
 (MODEN) Motts-Benedict.

Category 3: Primarily Toxic Discharge Models
 EXAM 2 (EPA, 1985)
 WASP 3, EUTRWASP, and TOXIWASP (EPA, 1986).

1. Evaluation of Potentially Appropriate Models

Those models considered to be potentially appropriate for dispersion of drilling fluids and produced water were evaluated. Below, the major characteristics and limitations of each

model are summarized and a recommendation as to the potential applicability of each for modeling shallow water dispersion of drilling fluids and produced water is provided.

1.1 Primarily Solid Phase Models (Mud Discharge Models)

1.1.1 Mud Discharge (OOC) Model Characterization:

- Time-dependent three-dimensional model.
- Calculates nearfield initial development of dynamic plume.
- LaGrangian treatment of diffusion phase; tracks individual clouds.
- Material settling out of dynamic plume acts as source of Gaussian distributed clouds.
- Concentrations in water column found by superposition of contributions from nearby clouds.
- Concentration throughout water column and on the bottom are provided at any time.
- Developed specifically for drilling muds.
- Allows for variable topography, time-variant density and velocity profiles, and wide range of discharge conditions.
- Diffusion coefficient calculation is dependent on surface and bottom conditions.

Limitations:

- Highly dependent on diffusion coefficient.
- The model does not account for the effects of flocculation of mud in water column.
- The algorithm used in the model to cause the early separation of fine material near the discharge source (during the jet phase) has no theoretical basis.
- The model cannot simulate the situation where the plume descends exactly vertically in shallow water or combined with a much higher vertical to horizontal velocity ratio.
- Probably not appropriate when surface waves induce significant variations in water depth (10–20%).
- Current version does not cover produced water; a revised model, not yet released, covers produced water.

Recommendation:

- Applicable at depths greater than 5 meters.
- Not applicable at depths less than 2 meters.
- Uncertain applicability from 2 to 5 meters.

1.1.2 EPA2-D model

Characterization:

- Time-dependent, two-dimensional model.
- Assumes plume is vertically mixed.

- Conservative in the nearfield in shallow water (assumes complete mixing); may not be conservative in deeper water (*i.e.*, where complete vertical mixing is progressively less valid).
- More applicable to the farfield.

Limitations:

- Does not include initial mixing.
- Highly dependent on turbulent diffusion.
- Not conservative for extremely short time scales or deeper water (see above).

Recommendation:

- Appropriate, especially for very shallow water (2 meters or less), but needs to be qualified.

1.1.3 DIFID and DIFCD models**Characterization:**

- Cover instantaneous and continuous discharge. Modified to include concentration profiles with depth. Developed for dredge muds.

Limitations:

- Only consider bottom deposition and horizontal distribution.
- Need to know how deep the plume is.

Recommendation:

- Not appropriate because superseded by other models (OOC model for example).

1.1.4 DRIFT model**Characterization:**

- Joint probabilistic trajectory model for current speed and direction.
- Focuses on bottom deposition.

Limitations:

- Calculation does not depend on diffusion coefficients.
- Covers only low rate of cuttings discharge.

Recommendation:

- May be appropriate, but has limited utility.

1.2 Primarily Liquid Phase Models**1.2.1 PDS model****Characterization:**

- The only model that considers surface plumes.
- Covers surface discharge and assumes plume floats on surface and there is no interaction with bottom.
- Perhaps useful with low salinity and high temperature.

Limitations:

- Does not apply if drilling material is negatively buoyant.
- Model does not include sediment or boundary effects.

Recommendation:

- Appropriate for surface plumes.

1.2.2 OUTPLM and UMERGE models**Characterization:**

- UMERGE is a revised version of OUTPLM model.

- Two-dimensional, multiple port version of OUTPLM model.
- Discharges from several ports merge together in a "top-hat" profile.
- Current speed and direction are constant with time.

Limitations:

- Does not include development zone.
- Current must be normal to line of diffuser.
- Assumes no interaction with surface or bottom boundaries.
- Does not account for settling of solids or ambient stratification.

1.2.3 UDKHDEN model**Characterization:**

- Three-dimensional model.
- No restrictions on discharge direction with respect to ambient current.
- Diffuser, single or multiple port.
- Allows for variable density stratification and variable current.

Limitations:

- Assumes currents and ambient density are constant with time.

Recommendation:

- Appropriate for negatively buoyant liquid phase discharges until plume reaches to within one-half to one plume width of the bottom.

1.2.4 MOBEN model**Characterization:**

- Two-dimensional model.
- Liquid phase, vertically integrated discharge over shallow depth.
- Assumes constant depth.
- Discharge from rectangular trough.

Recommendation:

- May be useful in shallow water.

1.3 Primarily Toxic Discharge Models**1.3.1 EXAM 2 model**

- May have some applicability because of eutrophication and dissolved oxygen components.

- Probably is concentration-dependent.

- Need to convert measured effluent BOD to theoretical values.

- Input data availability is questionable.

1.3.2 WASP 3, EUTRWASP, and**TOXIWASP****Characterization:**

- Includes hydrodynamics, conservative mass transport, eutrophication-dissolved oxygen kinetics, and toxic chemical-sediment dynamics.

- Multidimensional and time variable capabilities.

- Simulates conventional and toxic pollution.

Limitations:

- User must write applicable kinetic equations for a given problem.

- Simulates transport and transformation of a single chemical.

- Chemical concentration must be near trace levels.

- Requires user to specify flow fields.

Recommendation:

- Limited utility for a multi-constituent effluent, such as drilling fluids.

2. Recommended Modeling Approach

The OOC model, which was developed principally for drilling muds, appears to be potentially applicable for shallow water dispersion of drilling fluids at depths greater than 5 meters, and possibly to 2 meters. At any depth below the fixed depth to which the OOC model is found to be inappropriate, the EPA Time-Dependent, Two-Dimensional Model for Predicting Distribution of Drilling Muds Discharged to Shallow Water (EPA2-D) should be used. While this model is appropriate at a depth of 2 meters, it may require additional field verification for shallower water.

The EPA liquid phase models, particularly UMERGE and UDKHDEN, are potentially applicable for modeling nonsurface or vertically downward discharge of produced water. For surface discharge, the PDS model may be appropriate; it is the only model that considers surface plumes. When the plume reaches to within one-half to one plume width from the surface or bottom, (the point at which UMERGE and UDKHDEN are no longer appropriate), a two-dimensional model such as the Motts-Benedict (MOBEN) model or the EPA2-D model should be used.

As a part of this notice, the Agency is requesting comments on the list of models reviewed, the models selected as being appropriate for shallow water discharges of drilling fluids and produced water, and the model scenarios used to assess both models behavior and effluent behavior. The discharge, operational, and ambient conditions that were used as input to the selected models and the results of model runs are presented in the draft report titled "Analysis of Effluent Dispersion Models Potentially Applicable to Shallow Water Discharges from Oil and Gas Activities" (4), which is available in the record of this rulemaking.

References for Section V

(1) U.S. EPA, 1987, Estimates of Degree of Sediment Alteration Associated with Various Levels of Mercury and Cadmium in Barite.

(2) U.S. Congress, Office of Technology Assessment, Wastes in Marine Environments, OTA-0-334 (Washington, DC: U.S. Government Printing Office, April 1987).

(3) Trefrey, J.H., et al., 1986, "Draft and Final Report to the Offshore Operators Committee: Forms, Reactivity, and Availability of Trace Metals in Barite."

(4) U.S. EPA, 1988, "Analysis of Effluent Dispersion Models Potentially Applicable to

Shallow Water Discharges from Oil and Gas Activities."

Part 2

I. Summary

EPA is currently reconsidering the prohibition on the discharge of drill cuttings that contain oil-based drilling fluid, as proposed in the August 26, 1985 proposal and is considering as an alternative the development of an oil content limitation for drilling waste streams. "Oil content" would be used as a non-conventional indicator pollutant for the BAT and NSPS levels to control the discharge of priority and non-conventional organic pollutants present in the hydrocarbons that are added to drilling fluids, both as a lubricity agent and for spotting purposes, and in the hydrocarbons from formation fluids that are entrained in the drilling fluid. These same priority and non-conventional pollutants are present in the associated drill cuttings waste stream and may be similarly controlled by an oil content limitation. An oil content limitation would apply to the discharged drilling waste and would not differentiate between diesel oil or mineral oil. The oil content measurement would be performed according to the "retort-gravimetric" procedure discussed in section IX of this part and is presented in Appendix A of this notice.

Specifically, the Agency is now considering the establishment of an oil content limitation of up to 1.0% by weight (whole sample basis) for drill cuttings based upon application of thermal distillation, thermal oxidation, or solvent extraction technologies. An oil content limitation would apply to drill cuttings associated with both water-based and oil-based drilling fluids and would apply as a maximum value (no single sample to exceed). The Agency believes that the technologies discussed below are technologically feasible to implement for the treatment of drill cuttings to reduce oil content.

The Agency also has considered the establishment of an oil content limitation for oil-based drilling fluids. The Agency has tentatively rejected this approach because existing regulations (BPT) effectively prohibit the discharge of oil-based drilling fluids.

Finally, the Agency has considered the establishment of an oil content limitation for waste-based drilling fluids that contain added or entrained oil. The Agency believes that processing rate and storage limitations may make it impracticable to implement an oil content limitation for water-based drilling fluids based on using any of these technologies to treat water-based

drilling fluids at offshore drilling sites. These factors are discussed in Section V of this part of today's notice.

The technologies discussed in this part of the notice would achieve a residual oil content in the processed cuttings which would be lower than those achieved using cutting washer (*i.e.*, BPT) technology. The current regulation prohibits the discharge of "free oil" as evidenced by the presence of a visible sheen upon the receiving water after discharge of the drilling waste.

The BAT and NSPS regulations for drill cuttings proposed on August 26, 1985 would prohibit the discharge of drill cuttings associated with the use of an oil-based drilling fluid. Several commenters on the proposed regulations argued that the discharge of cuttings associated with oil-based fluids should be allowed if the oil content were controlled to acceptable levels, *i.e.*, the discharged cutting did not violate the sheen test used to detect free oil. The Agency proposed to prohibit unconditionally the discharge of such cuttings because of substantial historical experience with the seepage of oil from such cuttings after they were discharged. Though such cuttings may comply with the BPT "free oil" limitation upon discharge, they could release substantial amounts of oil from their location on the ocean floor long after the original discharge occurred.

Allowing the discharge of treated drill cuttings associated with oil-based drilling fluids, as opposed to a prohibition on their discharge, could lead to the continued development of control/treatment technologies, reduced regulatory compliance costs for the offshore segment of the industry, and alleviation of potential problems with land disposal of drilling wastes in coastal areas.

The remainder of this part of today's notice presents more detailed information and discussion on oil content limitations for drilling wastes. After consideration of the comments and any additional data received during the comment period on this notice in addition to information in the existing rulemaking record, the Agency may decide to propose effluent limitations guidelines and standards for the control of oil content in drilling wastes.

II. Background

As stated elsewhere in this notice, on July 2, 1986 EPA Regions IV and VI issued a general National Pollutant Discharge Elimination System permit (the General Permit) regulating oil and gas exploration, development, and production activities in federal waters of

the Gulf of Mexico. One of the requirements of the general permit is a prohibition on the discharge of drill cuttings associated with the use of oil-based or inverse emulsion fluids.

During the comment period on the draft general permit, SEDSCO, Inc. (now Thermal Dynamics, Inc.) commented that it had developed a treatment technology which would be more effective in removing residual oil from drill cuttings than the previously available treatment methods. However, at that time, EPA decided that sufficient data were not available on the new technology to justify an alternative effluent limitation. The general permit implemented the "no discharge of free oil" requirement by prohibiting the discharge of any drill cuttings associated with oil-based muds. The final general permit for the federal waters of the Gulf of Mexico was issued on July 9, 1986.

On August 15, 1986, Thermal Dynamics, Inc. (TDI) sought to stay the general permit limitation for the drill cuttings waste stream. TDI argued that, in view of its newly developed technology, prohibiting the discharge of drill cuttings associated with an oil-based drilling fluid was unnecessarily stringent as an implementation of the "no discharge of free oil" limitation. TDI stated that sufficient data were available to EPA to demonstrate that substantial reductions in the oil content of cuttings could be achieved by thermal distillation. TDI stated that this new technology could reduce the oil content of drill cuttings to a level equivalent to the "no discharge of free oil" limitation.

At the time Thermal Dynamics sought to stay the general permit limitation, only limited information was available on the efficiency of those technologies in actual use. EPA Region VI issued a "demonstration" permit to an oil company to allow for field data to be generated on the operation of a thermal distillation treatment system. A vendor-supplied thermal distillation unit was used to treat drill cuttings produced during actual drilling operations with oil-based drilling fluid. The cutting waste stream, processed cuttings, and associated by-product waste streams were characterized for oil content, solids content, priority pollutant organics and metals, RCRA (Resource Conservation and Recovery Act) ICR characteristics (ignitability, corrosivity, reactivity) and acute toxicity (LC50).

In view of the additional information obtained on this and other technologies for treating drilling wastes, EPA is reconsidering the proposed prohibition on the discharge of drill cuttings that

contain oil-based drilling fluid. EPA is now considering alternatives to the proposed discharge prohibition.

One alternative being considered would allow the discharge of treated drill cuttings that meet a specified oil content limitation. Drill cuttings discharges would still have to achieve the BPT limitation of 'no discharge of free oil'.

III. Description of Technologies for Controlling Oil Content of Drilling Wastes

The preamble to the 1985 proposed regulations include a discussion of cuttings washer technology and its effectiveness for reducing the oil content of drill cuttings. The Agency found that cuttings washer systems that were studied were reported to reduce the oil content of drill cuttings to approximately 10% by weight. However, the Agency rejected the use of cuttings washer technology as a basis for an oil content limitation because it believed that the cuttings washer technology did not achieve a reduction in oil content of the drill cuttings sufficient to meet the BPT requirement of 'no discharge of oil'. Since 1985 the development and use of cuttings washer technology appears to have diminished, possibly due to the relatively high residual oil content of the processed cuttings and problems with proper disposal of by-product water/oil/detergent wastes.

After the proposed regulations were published, the Agency investigated other technologies for reducing the oil content of drilling wastes. These technologies fall into two general classes. In one class are thermal processes (thermal distillation or thermal oxidation). In the other class are solvent extraction processes. All of the technical and cost information provided by the vendors of these technologies and additional information collected by the Agency is available in the public record for this rulemaking.

The Agency has evaluated vendor technical information and collected performance data on the treatment of drilling wastes, specifically drill cuttings associated with the use of oil-based drilling fluids, by thermal distillation. This technology appears to be technologically feasible to implement for the reduction of oil contained in drilling wastes. Based on data obtained on these technologies, the costs on a per well basis of onsite treatment using thermal distillation or solvent extraction appear to be in line with the cost estimates for transport to shore and land disposal of drilling wastes.

The basic thermal distillation process has been adapted in variations by

several vendors. The process removes hydrocarbons and water from drilling fluids and drill cuttings. There are three types of thermal systems known to the Agency that are available for the treatment of drill cuttings:

T-1 Process

One type of system to treat drilling wastes consists of electrically heated chambers in which the drilling wastes are exposed to controlled heat sufficient to volatilize the residual oil and water in the wastes. (This will be referred to as the "T-1" process). The electrical energy required by the process is provided by generators at the treatment site.

The processed wastes in the form of a granular material are cooled and slurried by mixing with seawater and are then discharged to the ocean. The water and hydrocarbon vapors of driven from the wastes are condensed and then separated in an oil/water separator. The hydrocarbons recovered can potentially be recycled and reused in active mud system, subject to meeting the specifications for oil additives to the mud. Alternatives to recycling the recovered hydrocarbons would be to dispose of them separately or to market them for other purposes (e.g., heating fuel). If the recovered water meets effluent limitations for produced water, it could be suitable for discharge. The recovered water does not meet these effluent limitations if it may be appropriate to introduce it to the produced water treatment system. If there are no production facilities at the site the recovered water may need to be transported to another facility for adequate treatment or handling. Exhaust gases from the heating chambers in the thermal distillation unit and from the condenser would be treated to achieve appropriate air emissions standards.

These units are mobile and can be installed and operated on a rig to process wastes onsite. Full-size units have been field tested to treat drill cuttings. The T-1 process has been used to treat drill cuttings at an offshore facility in the Gulf of Mexico, in the North Sea, onshore in Alaska, and at onshore drilling sites in the Netherlands. At these locations, full-size units were used to treat drill cuttings for oil content reduction. The results of sampling performed by the vendor and by EPA indicate that the process can achieve significant reduction in the oil content of drill cuttings. Observations to date indicate that this technology is capable of reducing oil content levels to 1% or less by weight in processed cuttings (associated with oil-based muds) and that geographic location is not a factor or restriction in locating and operating

this technology. (Source: Vendor and EPA sampling data).

A thermal distillation unit of this type was tested under the demonstration permit issued by EPA. Performance data on this unit is presented and discussed in Section VII of this part of the notice.

T-2 Process

Another variation of the thermal distillation process has been developed for the reduction of hydrocarbons in drilling fluids and drill cuttings. (This will be referred to as the "T-2" process). The drilling wastes are routed to the drying section of the process where hydrocarbons and water are driven from the wastes. The water and hydrocarbons driven off the cuttings are passed through condensers and the resultant liquid is processed to separate the oil from the water. The oil is placed in storage for further purification and the water is processed to effect additional separation of oil from the water. If the recovered water meets effluent limitations for produced water, it could be suitable for discharge. The unit has been used for offshore operations on mobile drill units, platforms or barges.

A prototype "demonstrator" unit has been used to process drill cuttings. An oil content of less than 0.5% by weight was reportedly achieved in test with this unit. (Source: Vendor-supplied information). A full-scale unit has not yet been tested under actual filed conditions.

T-3 Process

A third variation on the thermal distillation technology has been developed. This process uses indirect heating to vaporize water and hydrocarbons adhering to drilling wastes. (This will be referred to as the "T-3" process). In this process, drilling wastes are fed to a blender which maintains a homogeneous slurry feed to the process unit. A closed heat transfer system around the processing unit provides the heat required to vaporize the water and hydrocarbons from the drilling waste. The proposed source of heat is exhaust gases from the rig electricity generator. The processed wastes are dry and granular in nature. The vaporized water and hydrocarbons are condensed for their recovery. The condensed hydrocarbons and water can be separated with potential for the hydrocarbons to be reused in the active mud system subject to meeting the specifications for oil additives to the mud. If the recovered water from the separator meets effluent limitations for

produced water, if could be suitable for discharge.

The process is implemented using a skid-mounted mobile unit which is reportedly suitable for use either offshore or onshore. This version of distillation technology has been tested on a pilot scale basis but not on a full-scale basis. Pilot-scale tests on drilling wastes are reported to have produced cuttings consistently with an oil content of 6% or less by weight. (Source: Vendor-supplied information).

T-4 Process

A thermal oxidation process has also been developed which can be used to treat drilling wastes. (This will be referred to as the "T-4" process). The process consists of a direct fired, countercurrent rotary kiln where the wastes are thermally oxidized at temperatures typically in the range of 1600 F to 2500 F. The kilns can be over 200 feet in length. The dried solids produced in this process are reportedly suitable for use as aggregates or fill materials. The hydrocarbons driven from the wastes are partially oxidized in the kiln, while virtually complete combustion is achieved in an oxidation chamber and afterburner. At least two of these facilities are known to be currently operating on the Gulf of Mexico coast. However, due to the scale of the equipment as currently demonstrated, this process can not be implemented offshore or moved from site-to-site. However, drilling wastes could be transported to such land-based facilities for processing.

SE Process

In addition to the thermal technologies described above, a process based on solvent extraction technology has been developed to treat drilling wastes for the reduction of oil content. (This will be referred to as the "SE" process). In this process, the drilling wastes are directed to an extraction column and contacted with solvent to extract the oil. The oil-laden solvent flows from the extractor column to an evaporator, a separation column and a separator where the oil and solvent are separated. The oil phase flows to the fluidizing oil holding tank and the solvent is recycled to the process. Oil levels as low as 0.3% by weight in the processed wastes are reportedly achieved using this process. (Source: vendor-supplied information). When used to process used drilling fluids, one vendor reports that the resultant mud solids can be recovered for reuse.

The types of solvents have been used in the solvent extraction processes investigated by the Agency—

chlorofluorocarbons and carbon dioxide. Either type of solvent reportedly will serve the operational needs of the process. Although the solvents are used and recovered in a closed-type system, there is potential for some solvent loss to the atmosphere. The Agency does not have quantitative information on the amount of such solvent losses from these processes. The Agency is particularly concerned about the potential for losses of chlorofluorocarbon-type solvents from these processes to the atmosphere because they contribute to depletion of the stratospheric ozone layer, and the Agency has recently limited their production. (53 FR 30566) The Agency is therefore soliciting comment and additional information to assess this potential, to quantify the rate and amounts of such losses, and to determine whether there are acceptable alternatives to use of chlorofluorocarbon-type solvents in these processes.

IV. Applicability of Thermal and Solvent Extraction Technologies for Treating Drilling Wastes

A. Drill Cutting

Hydrocarbons can be present in the drill cuttings as a result of the introduction of oil additives to the drilling fluid system for lubricity and spotting purposes and the entrainment of formation hydrocarbons in the drilling fluid system. When the drill cuttings are separated from the drilling fluid system, they contain some of the drilling fluids and drilling fluid system additives (e.g., oil). The drilling fluids and oil additives that are carried into the drill cuttings wastes after their removal from the bulk mud system by rig shale shakers and other separation equipment are considered to be part of the drill cuttings waste stream.

Based upon performance and cost information provided by several vendors of thermal and solvent extraction technologies, it appears to be technologically feasible to implement one or more of these technologies at offshore drilling sites for the reduction of oil content in drill cuttings. The costs (on a per well basis) of onsite treatment using thermal distillation or solvent extraction appear to be in line with the cost estimates for transport to shore and land disposal of the same wastes. This applies to drill cuttings associated with the use of either water- or oil-based drilling fluids. These technologies appear to be well-suited and efficient for the reduction of oil content of such wastes over a broad range of hydrocarbon content.

There appear to be no insurmountable technical difficulties associated with the placement of such equipment at offshore drilling sites, operation of the equipment, intermediate handling of raw cuttings wastes to be processed, and handling of processed cuttings wastes and by-product streams. These technologies are effective in achieving substantial reduction in the amount of hydrocarbons adhering to the drill cuttings. Specific levels of oil content in drill cuttings wastes processed by these technologies are presented in later sections of this notice.

B. Drilling Fluids

Oil-Based Drilling Fluids. Thermal distillation/oxidation and solvent extraction technologies appear to be suitable for processing materials with variable hydrocarbon content. Oil-based drilling fluids (i.e., invert emulsion) can typically contain 30% or more oil by volume (approx. 15% oil by weight). The high oil content (and low water content) of oil-based fluids should result in highly efficient removal and recovery of the oil by these technologies.

However, the existing BPT requirement of "no discharge of free oil" effectively prohibits the discharge of oil-based drilling fluids to surface waters of the U.S. An oil content limitation for oil-based drilling fluids that is based upon these technologies would be less stringent than the effective prohibition on the discharge of any of these wastes based upon the BPT requirement of no discharge of free oil. Because the Agency's interpretation of the Clean Water Act precludes the establishment of BAT, BCT, or NSPS limitations that are less stringent than BPT, it is not appropriate to consider such a limitation or standard that would allow a discharge of oil-based drilling fluids to surface waters.

Water-Based Drilling Fluids. Water-based drilling fluids to which oil has been added for lubricity or spotting purposes or such drilling fluids that contain entrained formation hydrocarbons are subject to the existing BPT requirement of "no discharge of free oil". However, the amount or concentration of oil contained in water-based drilling fluids for any of these reasons is at considerably lower levels than that in oil-based drilling fluids. Oil levels in such water-based drilling fluids typically range from nil to about 5% by volume (2.5% by weight). In many cases, water-based drilling fluids containing oil at levels in this range would not exhibit a visible sheen (BPT "no discharge of free oil") upon their discharge. This following discussion applies to the use

of thermal and solvent extraction technologies for treating such drilling fluids for the reduction of oil content.

Three major factors make the use of the technologies under consideration less practicable for treating water-based drilling fluids at an offshore drilling facility than for treating drill cuttings.

First, for a given well, the volume of drilling fluids to be handled is much greater than the volume of drill cuttings. Depending upon the capacity and processing rate capability of the treatment unit, the time to process waste drilling fluid generated during the drilling of a well could make it impractical to conduct the treatment operation at the offshore facility due to space restrictions for storing the material and extended time requirements for treatment if temporary storage of the raw wastes was available.

Second, even assuming that the waste drilling fluid generated during the drilling of the well can be processed effectively, there remains a substantial volume of drilling fluid to be disposed at the end of drilling. At the end of the drilling period, when the bulk drilling fluid system is ready to be disposed of, there is suddenly a large volume of drilling fluid that needs to be temporarily stored for subsequent processing (1400 bbl in the model case). Space for storing drilling fluids on an offshore oil facility is limited. Again, the length of time required to process the large volume of drilling fluids at the end of drilling may make it infeasible to store the drilling fluids on an offshore drilling facility prior to processing.

Third, in the case of the thermal technologies, the much higher relative water content of water-based drilling fluids requires a considerably higher input of thermal energy to the process in order to vaporize the water present. (The water must be vaporized in order to remove the oil). This directly increases the costs for treating the drilling fluid. In cases where the thermal process is operating at or near its maximum capacity, the high energy requirement (per unit of waste treated) may mean that the rate at which the drilling fluids can be processed will be substantially reduced. This in turn would require increased storage capacity for temporary onsite storage of the raw waste prior to treatment. (This factor would be of negligible consideration for the land-based thermal oxidation technology.)

One alternative might be to transport the bulk drilling fluid system to shore for subsequent treatment by one of the technologies under discussion. However, the cost for transportation to

shore for processing would add considerably to the total cost of treatment. It may also require either the expense of duplicate equipment on shore to process the bulk mud system or else the cost and disruption associated with relocation of the processing equipment from the offshore facility to shore. This additional expense could make the use of these technologies for treating the drilling fluid less attractive to industry than, for example, land disposal.

V. Pollutant Reduction and Cost Estimates

The Agency has evaluated the technological feasibility and costs of applying thermal technologies and solvent extraction technologies to: (1) Drill cuttings associated with oil-based drilling fluids; (2) drill cuttings associated with water-based drilling fluids which contain oil that has been added for lubricity purposes, spotting purposes, or which contain entrained formation hydrocarbons; and (3) water-based drilling fluids to which oil has been added for lubricity purposes, spotting purposes, or which contain formation hydrocarbons.

This third scenario was evaluated to obtain estimates of increased energy requirements and processing time for treating water-based drilling fluids with a high water content. As discussed earlier, the Agency concluded from this analysis that the thermal distillation and solvent extraction technologies under consideration may not be appropriate as a basis for an oil content limitation for water-based drilling fluids at an offshore drilling site.

A. Pollutant Reduction Estimates

This subsection presents a summary of the model drilling scenario which is then used to establish estimates of oil content reduction in drill cuttings and water-based drilling fluids wastes by the technologies described earlier in this part of today's notice. Then the resultant oil content reduction estimates are presented for drill cuttings and water based-drilling fluids. Although the Agency has tentatively concluded that the reduction of oil content in water-based drilling fluids may be impractical to implement at offshore drilling sites by these technologies, oil content reduction estimates are presented below to provide the reader with an indication of the potential of the technologies for treating such wastes.

The Agency's analyses of applying thermal processes and solvent extraction processes are based on a model 10,000 foot well in the Gulf of

Mexico, as presented in Section II of Part 1 of today's notice.

Drilling a "typical" 10,000 foot well is estimated to take 35 calendar days with 20 days of actual drilling time. The volume of drilling fluid to be handled from a 10,000 foot model well is 5349 barrels plus an additional 1400 barrel active mud system. The volume of drill cuttings to be handled from the 10,000 foot model well is 1430 barrels. These model well characteristics used in these analyses are based on the Agency's evaluation of recent industry surveys. (Sources: 10,000 ft. model well—"1984 Joint Association Survey on Drilling Costs", Dec 1985, API; Drilling waste volumes and drilling times—"Alternate Disposal Methods for Mud and Cuttings, Gulf of Mexico and Georges Bank, Dec. 1981, Offshore Operators Committee).

The untreated drill cuttings associated with oil-based drilling fluids are estimated to contain 20% oil by weight (approx. 55% oil by volume). Untreated drill cuttings associated with water-based drilling fluid to which oil has been added, as a spot, as a lubricity agent or from entrained formation hydrocarbon, are estimated to contain 1% oil by weight (approx. 2.8% oil by volume). Water-based drilling fluids with oil added for lubricity and spotting purposes are estimated to typically contain 5% oil by volume (approx. 2.5% oil by weight) and 58% water by volume (approx. 30% water by weight). This 5% oil content by volume (approx. 2.5% oil by weight) is for a model situation where oil is added to the mud system for lubricity and spotting purposes, or is present due to entrained formation hydrocarbons. (Sources: EPA estimates; industry estimates)

After treatment, the oil content of the drill cuttings from oil-based muds was estimated to be reduced to 1% by weight (approx. 2.8% by volume) when using thermal distillation and to 0.3% by weight (approx. 0.8% by volume) when using solvent extraction. (Sources: EPA and T-1, T-2 and SE vendor sampling data.)

Since the oil content of untreated drill cuttings from water-based muds in the model case is 1% (weight), there would be little or no expected reduction of oil content in such wastes when subject to thermal distillation. The oil content of drill cuttings from water-based muds is estimated to be reduced to 0.3% by weight (approx. 0.8% by volume) when using solvent extraction technology. (Sources: EPA and T-1, T-2, and SE vendor sampling data.)

After treatment, the oil content of the water-based drilling fluids was estimated to be reduced to 1% by weight

(approx. 2% by volume) when using thermal distillation and to 0.3% by weight (approx. 0.5% by volume) when

using solvent extraction (Sources: EPA estimates).

The volumes and weights of oil present in the drilling wastes before and after treatment are shown on Table 5.

TABLE 5.—OIL CONTENT REDUCTION OF DRILLING WASTES BY VARIOUS TREATMENT PROCESSES

Waste type	Total quantity of drilling waste ¹		Oil present before treatment ²		Oil removed	
	bbls.	lbs.	bbls.	lbs.	bbls.	lbs.
OIL-BASED Drill Cuttings (20% oil by weight) TD-1 & 2 Process Removal to 1% by wgt.....	1,430	1,330,000	792	266,000	752	252,000
OIL-BASED Drill Cuttings (20% oil by weight) SE Process Removal to .3% by wgt.....	1,430	1,330,000	792	266,000	780	261,500
WATER-BASED Drill Cuttings (1% oil by weight) TD-1 & 2 Process Removal to 1% by wgt.....	1,430	1,330,000	40	13,300	0	0
WATER-BASED Drill Cuttings (1% oil by weight) SE Process Removal to .3% by wgt.....	1,430	1,330,000	40	13,300	28	700
WATER-BASED Drilling Fluid (5% oil by volume) TD-1 & 2 Process Removal to 1% wgt.....	5,349	3,584,000	267	113,400	161	54,000
WATER-BASED Drilling Fluid (5% oil by volume) SE Process Removal to .3% wgt.....	5,349	3,584,000	276	113,400	235	79,100

Sources:
¹ "Alternate Disposal Methods for Mud and Cuttings Gulf of Mexico and Georges Bank", Dec. 1981, Offshore Operators Committee.
² EPA Estimates.

b. Operating Costs

The Agency prepared treatment cost estimates based of information provided by vendors and by using standing engineering estimating procedures. These estimates have been prepared for two types of distillation processes (T-1 Process and T-2 Process) and for one solvent extraction (SE-Process) process applied to drill cuttings and water-based drilling fluids.

The costs for leasing and operating these treatment processes differ from vendor to vendor. Two vendors had one lease rate for actual drilling days and a lower rate for standby days. The other vendor had a fixed lease rate for both drilling and standby days.

A monetary value was assigned to the oil recovered by the treatment process. The model scenario assumes that all of the oil removed from the drilling wastes by a given treatment process will be recovered. However, in practice the amount of recovered oil will be less than 100% of that removed from the wastes, due to losses by fugitive emissions, vapor condensation losses and oil/water separation efficiency for distillation processes and due to solvent recovery efficiencies for the extraction process. This loss is assumed to be small and not to significantly affect the cost of using a particular technology. The value of the recovered hydrocarbon is estimated to be \$26.50 per barrel (source: vendor-supplied information). This full value of the recovered oil

would be realized only if the oil is suitable for reuse in drilling fluid. While it is reported that the recovered oil can be reused in mud systems, the Agency is not aware that this practice has been tested yet on a full-scale basis.

The cost estimates include equipment rental costs, personnel costs, energy costs, and transportation costs. The equipment rental and energy costs are based upon whether the unit is in operating mode or standby mode. As an example, a breakdown of the cost estimate for treatment of drill cuttings by one of the thermal distillation processes (T-1) operating for 20 days and on standby for 15 days is shown in Table 6. In this example, the estimated energy cost is the cost of fuel for the generator used to provide electrical energy to operate the treatment equipment and to provide thermal energy for processing the waste. (source: cost information from vendors, EPA estimates).

The cost presented in Table 6 were developed with the conservative assumption that four wells are drilled consecutively. Mobilization and demobilization costs for drilling multiple wells at a given site are allocated among the number of wells (in this case four) assumed to be drilled during a given campaign. Thus, each well is allocated only a part of the total mobilization and demobilization costs for the treatment unit.

TABLE 6.—COMPONENT TREATMENT UNIT LEASE AND OPERATING COSTS, THERMAL DISTILLATION (T-1 PROCESS)

[Drill cuttings from oil-based or water-based drilling fluids]

Rental for 20 day actual operating period (\$4,000 per day).....	= \$80,000
Rental for 15 day standby period (\$1,500 per day).....	= 22,500
Energy costs for unit during operation (\$180 per day, 20 days).....	= 3,600
Personnel living on rig (2 men x 35 days x \$35 per day).....	= 2,450
Transportation to rig (one boat for one day)*	= 750
Set-up on rig (including use of crane)*	= 2,500
Tear down (including crane use)*	= 1,250
Transportation to shore (one boat for one day)*	= 750
Shore support.....	= 3,000
Transporting personnel to and from rig weekly (5 x \$600)	= 3,000
Total	= 119,800

Note.—(1) Costs treating for drill cuttings assume the unit will be operating for 20 days and on standby for 15 days.
 (2) Costs marked * are based on mobilization and demobilization costs being apportioned between 4 wells drilled consecutively at the same facility.
 (3) Cost of deck space usage is not included.
 Source: Vendor-supplied information; EPA estimates.

The operating costs in Table 7 were estimated in a similar manner for the other two processes being considered.

C. Drill Cuttings from Oil- and Water-Based Drilling Fluids

Cost estimates were developed for the treatment of drill cuttings. The costs for

leasing and operating two types of thermal distillation units (T-1 and T-2) and the solvent extraction unit (SE) over a 35 day drilling period, including auxiliary costs, were estimated. In this scenario where the systems are used to treat only drill cuttings, it is assumed that the unit will be operating only during the 20 days of actual drilling. The equipment lease and energy costs are calculated accordingly. The costs for operating these processes are essentially the same whether they are used to treat drill cuttings associated with oil-based drilling fluids or water-based drilling fluids. These costs are summarized in Table 7.

As described previously, a value of \$26.50 per barrel is assigned to the oil recovered by the treatment process assuming recovered oil is suitable for

reuse in the drilling fluid system. These costing examples include the assumption that all of the oil removed from the drilling wastes is recovered for reuse.

Oil-Based Cuttings.

The drill cuttings from an oil-based mud are estimated to have a 20% oil content by weight (approx. 55% by volume); the volume of oil on the cuttings would therefore be 792 barrels. The volume of oil remaining on the cuttings after treatment by thermal distillation to reduce the oil content to 1% by weight (approx. 2.8% by volume) would be 40 barrels. The value of the recovered oil would therefore be \$19,900 (752 bblx\$26.50). The volume of oil remaining on the cuttings after treatment by solvent extraction when

reducing the oil content to 0.3% by weight (approx. 0.8% by volume) would be 12 barrels. The value of the recovered oil would therefore be \$20,700 (780 bblx\$26.50). Water-based Cuttings.

The cuttings from a water-based mud are estimated to have a 1% oil content by weight (approx. 2.8% by volume) and the volume of oil on the cuttings would therefore be 40 barrels. There would be little, if any, expected reduction in oil content where these wastes are subjected to treatment by thermal distillation. The volume of oil remaining on the cuttings after treatment by solvent extraction when reducing the oil content to 0.3% by weight (approx. 0.8% by volume) would be 12 barrels. The value of the recovered oil would therefore be \$740 (28 bblx\$26.50).

TABLE 7.—COSTS OF TREATMENT FOR DRILL CUTTINGS¹

Procedure	Thermal distillation TD-1 process			Thermal distillation TD-2 Process			Solvent extraction SE process		
	Cost/unit	Unit No.	Total cost	Cost/unit	Unit No.	Total cost	Cost/unit	Unit No.	Total cost
Cuttings From Oil-Based Drilling Fluids									
Rental-drilling.....	4,000	Day 20.....	= \$80,000	1,550	Day 20.....	= \$31,000	4,200	Day 20.....	= \$84,000
Rental-no drill.....	1,500	Day 15.....	= 22,500	1,500	Day 15.....	= 23,250	2,000	Day 15.....	= 30,000
Energy cost.....	180	Day 20.....	= 3,600	180	Day 20.....	= 3,600	Included	Day 20.....	= 0
Living cost.....	70	Day 35.....	= 2,450	70	Day 35.....	= 2,450	70	Day 35.....	= 2,450
Trans. to rig.....	750	Each 1.....	= 750	750	Each 1.....	= 750	750	Each 1.....	= 750
Rig set-up.....	2,500	Each 1.....	= 2,500	2,500	Each 1.....	= 2,500	2,500	Each 1.....	= 2,500
Rig tear-down.....	1,250	Each 1.....	= 1,250	1,250	Each 1.....	= 1,250	1,250	Each 1.....	= 1,250
Shore support.....	3,000	Each 1.....	= 3,000	3,000	Each 1.....	= 3,000	3,000	Each 1.....	= 3,000
Trans. to shore.....	750	Each 1.....	= 750	750	Each 1.....	= 750	750	Each 1.....	= 750
Weekly Trans.....	600	Each 5.....	= 3,000	600	Each 5.....	= 3,000	600	Each 5.....	= 3,000
Total.....			119,800			71,550			127,700
FOR OIL BASED DRILLING FLUID									
1,430 bbls drill cuttings treated:									
Cost of treatment.....			= 119,800			71,550			127,700
Cost of treatment per barrel.....			= 84			50			89
Value of recovered oil.....			= 19,900			19,900			20,600
Net cost of treatment.....			= 99,900			51,650			107,100
Net cost of treatment per barrel.....			= 70			36			75
Cost of onshore disposal.....			= 66,400			66,400			66,400
Onshore disposal cost ² per barrel.....			= 46			46			46

¹ All three treatment units are assumed to take 20 days to process 1,430 barrels of drill cuttings.

² Onshore disposal costs assume rigs are retrofitted for cuttings storage.

D. Water-Based Drilling Fluids

Cost estimates were prepared for the treatment of water-based drilling fluids in order to assess increased energy costs and processing times for the treatment of drilling fluids as compared to drill cuttings. (The factors which may make the use of this technology to treat water-based fluids at an offshore oil facility less practicable than for treating drill cuttings are described in Section V of this part of today's notice.)

The costs of renting and operating the thermal distillation unit and the solvent extraction unit over a 35 day drilling period, including auxiliary costs, were estimated. It was assumed that in order to treat the larger volume of drilling

fluids the unit will be required to process drilling fluids every day during the entire 35 day drilling period. The equipment rental and energy costs were calculated accordingly.

The average oil content of water-based drilling fluid is estimated to be 5% oil by volume (approx. 2.5% by weight), when oil is added to the mud either as a spotting fluid, a lubricity agent, and/or contains entrained formation oil. The volume of oil in the 5349 barrels of drilling fluid (not including the active mud system) to be treated would therefore be 267 barrels. The volume of oil remaining on the drilling fluids, after treatment by thermal distillation when reducing the oil content to 1% by weight (approx. 2% by volume), is 107 barrels.

The value of the recovered oil would therefore be \$4300 (160 bbl x \$26.50). The volume of oil remaining on the drilling fluids after treatment by solvent extraction when reducing the oil content to 0.3% by weight (approx. 0.6% by volume) is 32 barrels. The value of the recovered oil would therefore be \$6,200 (235 bbl x \$26.50).

E. Comparison of Onsite Treatment Costs with Onshore Disposal Costs for Drilling Wastes

The detailed costs are presented in the EPA report titled "Costs, Energy Requirements and Processing Rates for Treating Drilling Fluids and Drill Cuttings using Thermal Distillation and Solvent and Solvent Extraction

Processes" which is available in the record of this rulemaking. These costs are summarized on a "per barrel of raw waste" basis in Table 8 below and are compared with transport to shore and land disposal costs of the wastes. The thermal distillation and solvent extraction technology costs in Table 8 include a credit for recovered oil at an estimated economic value of \$26.50 per barrel of oil.

The transport/land disposal option costs are presented for three scenarios. These three scenarios are presented on the basis of the ability to store the wastes during high seas or offload these wastes for transport to shore as follows:

1. For rigs with no storage space for drilling wastes, but designed for loading boats in seas with wave heights of up to 6 feet. If wave heights exceeded 6 feet, drilling would have to cease for the period that the wave heights were in excess of 6 feet and supply boats were unable to tie up at the facility.

2. For rigs with no storage space for drilling wastes, but designed for loading boats in seas with wave heights of up to 10 feet. If wave heights exceeded 10 feet, drilling would have to cease for the period that the wave heights were in excess of 10 feet and supply boats were unable to tie up at the facility.

3. For rigs retrofitted for drilling wastes storage. These rigs could continue to drill even when supply boats were unable to tie-up at the facility.

The costs for land disposal in Table 8 include onshore disposal costs, handling costs, container rental costs, transportation costs, and downtime costs for rigs with no storage space or retrofit costs for rigs fitted with storage space. Capital costs associated with retrofitting an offshore rig with sufficient storage capacity and deck space to accommodate storage of drilling wastes were estimated. These retrofit costs were apportioned among the estimated number of wells drilled from a rig during a 5-year estimated life of the rig equipment. These scenarios are based upon prior industry-sponsored work submitted during the proposed comment period. The Agency has reviewed the industry study documentation and found the information to be reasonable for the purpose of establishing these scenarios. (Source: "Water-Based Drilling Fluids and Cuttings Disposal Options Survey", Feb. 1986, Walk Haydel and Associates).

The transportation costs were based upon daily rental costs for supply boats. These costs were not sensitive to the distance between the offshore facility

and the onshore transfer facility and disposal site. The rigs with no storage capacity were assumed to require two dedicated supply boats throughout the entire 35 day drilling period. The rigs retrofitted with storage capacity were assumed to require two dedicated supply boats for the first 18 days of the drilling period and one dedicated supply boat for the remaining 17 days of the drilling period. (source: "Water-Based Drilling Fluids and Cuttings Disposal Option Survey", Feb. 1986, Walk Haydel and Associates).

The majority of operators would, in all probability, decide to retrofit rigs for drilling fluid storage since this would result in an overall lower cost for the disposal of drilling fluids. (source: "Water-Based Drilling Fluids and Cuttings Disposal Option Survey", Feb. 1986, Walk Haydel and Associates). The costs are lowered because supply boats would not be dedicated solely to drilling waste disposal. It was therefore estimated that 80% of the rigs would be retrofitted, 10% would operate using a maximum permissible wave height of 10 feet and 10% would operate using a maximum permissible wave height of 6 feet. (EPA estimate).

TABLE 8.—COST OF ONSITE TREATMENT V. ONSHORE DISPOSAL DRILL CUTTINGS AND WATER-BASED DRILLING FLUIDS—THERMAL DISTILLATION, SOLVENT EXTRACTION, ONSHORE DISPOSAL—MODEL 10,000-FOOT WELL

(Dollar per barrel)

	Drill cuttings associated with oil-based drilling fluids	Drill cuttings associated with water-based drilling fluids	Water-based drilling fluids
Onsite treatment using thermal distillation T-1 process	70	(*)	32
Onsite treatment using thermal distillation T-2 process	36	(*)	16
Onsite treatment using solvent extraction SE process	75	89	29
Transport to shore for disposal—no storage, max. 6 ft. waves	78	78	58
Transport to shore for disposal—no storage, max. 10 ft. waves	61	61	45
Transport to shore for disposal—rig retrofitted for storage	46	46	33

* No expected reduction in oil content.

Notes to Table 8:

- (1) Costs are in dollars per barrel of raw waste rounded to the nearest whole dollar.
- (2) Costs for drill cuttings are based upon handling 1430 bbl of drill cuttings from the model size well. (1)
- (3) Costs for drilling fluids treatment by thermal and solvent extraction are based upon handling 5349 bbl of water-based drilling fluids. This excludes the active mud system volume of 1400 bbl. It is uncertain whether onsite treatment is feasible for the active mud system (1400 bbl). (1/2)
- (4) Costs for onsite treatment consist of equipment rental costs, energy costs, personnel costs and mobilization and demobilization costs. (3)

(5) Costs for onshore disposal consist of land disposal costs, handling costs, container rental costs, transportation costs and retrofit costs for rigs fitted with storage space for drilling wastes or downtime costs for rigs with no storage space. (4)

Sources:

- (1) "Alternate Disposal Methods for Mud and Cuttings, Gulf of Mexico and Georges Bank; Dec. 1981, Offshore Operators Committee).
- (2) EPA estimate.
- (3) Vendor-supplied information; EPA estimates.
- (4) "Water-Based Drilling Fluids and Cuttings Disposal Option Survey"; Feb. 1986, Walk Haydel and Assoc.

VI. Performance Data

A. Field Sampling

During the period September 14 to 17, 1987, the Agency performed sampling of feed, waste and by-product streams associated with a thermal distillation unit (T-1 process) that was operating in the South Pass Block of the Gulf of Mexico. The thermal distillation unit was used to process cuttings generated from a well drilled at an offshore facility in the Gulf of Mexico. Oil-based muds were utilized at the well from a depth of 4,900 feet to the bottom of the well at 13,944 feet. The diameter of the hole was

12.25 inches and the well was being drilled at a rate of 140 feet per hour. Only a portion of the drill cuttings generated at this well were processed by the thermal distillation unit. Due to the existing configuration of the rig cuttings collection system, the raw cuttings feed was composed only of the cuttings from the primary shale shaker.

The following waste and by-product streams were generated by the particular thermal distillation unit that was tested: processed cuttings, condensed hydrocarbon, condensed water, air emissions. The processed cuttings were mixed with seawater and sluiced to discharge from the facility. The condensed vapors (oil/water) were directed to an oil/water separator which had two discharge streams—a condensed hydrocarbon stream and a condensed water stream. The treatment system also had a stack for air emissions.

Samples were collected by EPS from the test unit over a four day sampling period. Samples were taken of the raw cuttings, the processed cuttings and the combined processed cuttings/seawater stream. The oil content of both the raw cuttings feed and the processed cuttings was analyzed using retort-gravimetric and soxhlet extraction methods. The oil content of the combined seawater/cuttings stream was analyzed prior to discharge, using the gravimetric extraction method. The raw cuttings feed and the processed cuttings were analyzed for metals, priority organics,

percentage solids and for ICR/RCRA components (ICR tests are for ignitability, corrosivity and reactivity; RCRA is the Resource Conservation and Recovery Act). The combined treated cuttings/seawater stream to be discharged was analyzed for total suspended solids. Bioassay tests were performed on samples of the raw cuttings and the processed cuttings. Samples were also taken of the condensed hydrocarbon and water streams. These samples were analyzed for oil content using the gravimetric extraction method, and for priority organics. Samples of the condensed water discharge stream were also analyzed for total suspended solids.

Temperature measurements and pH readings were taken of the selected raw waste, treated waste and by-product streams. Tests for settleable solids in the raw cuttings, the condensed water stream, the combined treated cuttings/seawater stream and in background seawater were conducted at the facility. Air sampling of the thermal unit emissions was not possible due to the unavailability of air sampling personnel during the sampling effort.

B. Observations and Sampling Results

During the sampling program, the vendor demonstrated the ability to set up and run a thermal distillation unit on an offshore development facility to treat drill cuttings associated with oil-based muds.

The average oil content of the raw cuttings was found to be 7.11% by

weight using soxhlet extraction analysis and 5.82% by weight using the retort-gravimetric method. The raw cuttings were considerably lower in oil content than expected for the type of mud being used. This was probably because the only source of cuttings used as feed to the test unit was the primary shale shaker. The cuttings from the primary shale shaker are physically the largest cuttings in the entire cuttings recovery system. The smaller, finer cuttings from the secondary shaker, the desilter and the centrifuge sections of the cuttings recovery system would have the higher oil content due to their higher surface area. A composite sample of all of the cuttings generated at the well would be expected to have an oil content of 15% to 20% by weight (source: EPA estimate; Conoco, Inc. estimate).

The thermal distillation unit was shown, when operating properly, to be able to consistently reduce the oil content of drill cuttings, separated from an oil-based mud at the primary shale shaker, to less than 1% by weight (less than 2.8% by volume). The processed cuttings were dry and granular in appearance. The results from the sampling episode therefore indicate that the thermal distillation unit tested could achieve a significant reduction in the oil content of drill cuttings.

The results of oil analyses of samples of raw and treated wastes and by-product streams are presented in Table 9.

TABLE 9.—THERMAL DISTILLATION OF DRILL CUTTINGS (OIL-BASED MUD), AVERAGE OIL CONTENT, PERCENT BY WEIGHT

	Soxhlet method ¹	Retort-gravimetric method ²	Gravimetric method ³
Raw cuttings.....	7.11	5.82	Not appr.
Proc. cuttings	0.06	0.53	Not appr.
Combined seawater/cuttings	Not appr.....	Not appr.....	0.06.
Condensed hydrocarbons	Not appr.....	Not appr.....	97.4.
Condensed water	Not appr.....	Not appr.....	0.06.
Sea water	Not appr.....	Not appr.....	0.003.

Notes:

"Not Appr." indicates that a particular analytical method was not an appropriate analytical method for type of waste stream sampled.

¹ Method 503D, Oil & Grease, Extraction Method for Sludge Samples. Standard Method for the Examination of Water and Wastewaters; APHA, AWWA, WPCF; 16th Edition, 1985.

² Proposed Method 1651, Total Oil and Diesel Oil in Drilling Fluids and Drill Cuttings by Retort Gravimetry and GCFID. Appendix A of this notice. This is the Agency's preferred method for oil content determinations for drilling wastes with relatively high solids content.

³ Method 413.1, Oil & Grease, Gravimetric (extraction). Methods for Chemical Analysis of Water and Waste, EPA-600/4-79-020, U.S. EPA, March 1979.

Acute toxicity was measured by conducting static, 96-hour toxicity tests with mysids on the suspended particulate phase (SPP) of raw and processed drill cuttings. The SPP was prepared by mixing the drill cuttings with seawater (1:9 by volume), allowing the mixture to settle for 1 hour, and decanting the SPP. Three subsamples of one sample of raw cuttings were tested. The 96-hour LC50s were 3.2%, 8.5% and

1.5% SPP. Two samples of processed cuttings were tested; the 96-hour LC50s were 28.7% and 27.9% SPP.

Samples of the raw cuttings, processed cuttings, condensed hydrocarbons and condensed water were analyzed for organics. A total of ten (10) samples—one raw cuttings, four processed cuttings, one condensed hydrocarbon and four condensed

water—were each analyzed for two hundred and thirty-four (234) organics.

Twenty-eight organic compounds were detected at concentrations above their detection limits in some or all of the samples. The remaining two hundred six organics compounds were either not detected or were quantified at a level below the method detection limit.

Detailed discussion and results of this sampling program are presented in the

EPA document titled "Report on the Results of Field Sampling or Thermal Dynamics Inc. Treatment of Drill Cuttings on Conoco South Pass 75 Platform September 14-17th, 1987". This report is part of the record of this rulemaking and is available for inspection as described in the "addresses" section of this notice.

VII. Oil Content or Untreated Drilling Wastes

This section presents a summary of the Agency's estimates of the quantities of untreated drill cuttings and water-based drilling fluids that would not meet an oil content effluent limitation of 1% or less (weight basis). These estimated quantities of drilling wastes would either require treatment to comply with an oil content limitation or, alternatively, the wastes could be disposed of in another manner such as by transport to shore for land disposal at an acceptable waste disposal site.

A. Drill Cuttings

Oil-Based Cuttings. All drill cuttings associated with oil-based drilling fluids would require treatment or land disposal to comply with an oil content limitation of 1% or less (weight basis).

Water-based Cuttings.

Based upon the waste characteristics described above for the model situation, little if any of drill cuttings associated with water-based drilling fluids which contain oil added either as a lubricity agent or as a spotting fluid would likely require treatment to comply with an oil content limitation.

Some portion of drill cuttings associated with water-based drilling fluids to which no oil has been added (lubricity, spotting) may require treatment or land disposal to comply with an oil content limitation. This would be due to entrained formation oils in the drilling fluid system which in turn could adhere to the drill cuttings wastes. The Agency has no estimate of drilling waste volumes that would fall into this scenario (drilling wastes or drill cuttings). For the purposes of this analysis, the Agency assumed a zero quantity of drilling wastes in this scenario. The Agency solicits specific information which would allow for a reasonable estimate to be made of these drilling waste volumes.

The results of an industry survey indicate that approximately 12% of all wells drilled with water-based muds have oil added to the mud system for lubricity purposes. (source: Shell Oil, Burgbacher, 1985). As discussed previously, the drill cuttings generated under these circumstances are estimated to contain 1% oil by weight. (EPA

estimate). For this analysis then, most if not all drill cuttings from wells drilled with water-based muds are estimated to have a oil content of 1% by weight and thus would not require treatment or land disposal to meet an oil content limitation of 1% by weight.

In summary, drill cuttings from water-based muds to which (mineral) oil has been added for lubricity and/or spotting purposes would likely not require treatment or land disposal to comply with an oil content limitation of 1% by weight.

B. Water-Based Drilling Fluids

Water-based drilling fluids which contain oil added either as a lubricity agent or as a spotting fluid, or containing formation hydrocarbons in appreciable amounts would likely require treatment to comply with an oil content limitation in the range of 1% or less (weight basis).

Historical information supplied by the industry indicates that approximately 12% of all wells drilled with water-based muds can be expected to use oil as a lubricity agent (source: API). The amount of lubricity oil used varies from about 1% to 12% (volume basis), with an estimated average of 3%. This, all drillings fluids generated from such wells would require either treatment to reduce the oil content prior to discharge or transport to shore for land disposal to comply with an oil content limitation. (Source: 1986 API Drilling Fluids Survey.)

The results of a recent survey conducted by the Offshore Operators Committee indicate that approximately 22% of wells drilled with water-based muds can be expected to use oil as a spotting fluid (1986 Offshore Operators Committee Spotting Fluid Survey). Water-based drilling fluid to which oil is added as a spotting fluid at depths below 8,000 feet would likely contain oil in excess of 1% by weight, and thus would either have to be processed for removal of oil and then discharged or transported to shore for disposal. (The EPA model case use of oil added as a spotting fluid below a depth of 8,000 feet was estimated for model well characteristics.)

The total volume of drilling fluid to be handled from a 10,000 foot well is estimated to be 6749 barrels (including the active mud system), of which approximately 2076 barrels (including the active mud system) are generated between 8,000 feet and 10,000 feet (source: "Alternate Disposal Methods for Mud and Cutting for the Gulf of Mexico and Georges Bank", Dec. 1981, Offshore Operators Committee). Thus, the percentage of all water-based

drilling fluids used which would contain oil as a spotting fluid is estimated to be 6.8% (22% x 2076 bbl/6749 bbl).

Assuming, conservatively for aggregate costing purposes, that there is no overlap in the population of wells using oil as a lubricity agent and those using oil as a spotting fluid, an estimated total of 18.8% by volume of all water-based drilling fluids would require onsite treatment of onshore disposal to comply with an oil content limitation as discussed above.

VIII. Analytical Method for Total Oil Content

A method for retort distillation and gravimetry for determining the total oil content of drilling fluid and drill cuttings waste streams is published as part of today's notice for review and comment. The Agency has determined that existing approved analytical methods for measuring oil are not appropriate for drilling wastes and that the oil content method appearing in Appendix A of this notice is the appropriate test procedure.

This same method (Proposed Method 1651, "Total Oil and Diesel Oil in Drilling Muds and Drill Cuttings by Retort Gravimetry and GCFID") includes additional steps for determining the identity and concentration of diesel oil, and is presented in its entirety in Appendix A of this notice.

The retort distillation method has been widely used by the industry for testing drilling muds and is simple to perform on offshore facilities in remote conditions. The version of the method presented in Appendix A has an estimated detection limit of 200 mg/kg (0.02% by weight). Documentation on precision and accuracy measurements of the test method is included in the record for this rulemaking.

IX. Request for Comments

As previously stated, the Agency is considering a BAT and NSPS oil content limitation of up to 1.0% by weight for drill cuttings associated with either oil-based or water-based drilling fluids. Such a limitation may be based upon attainable performance of the control and treatment technologies discussed in this notice and prior notices pertaining to this rulemaking. The Agency solicits comment on all aspects of such a BAT and NSPs oil content limitation for control of priority and toxic non-conventional pollutants in the hydrocarbons present in drill cuttings. This limitation would apply to all drill cuttings discharges to surface waters, whether or not oil is added to the associated drilling fluid system.

Moreover, for cuttings associated with oil-based muds, this oil content limitation would replace the prohibition on the discharge of such cuttings. The Agency particularly solicits comment on: (1) Whether such an oil content limitation is appropriate for drill cuttings; (2) the appropriate technology basis for an oil content limitation; and (3) whether an oil content limitation should apply in addition to or instead of one or more of the other limitations and standards for drill cuttings presented in Part 1 of this notice.

The Agency also invites comment on all aspects of establishing BAT and NSPS oil content limitations for water-based drilling fluids. The Agency particularly solicits comment on the practicality and technical achievability of processing water-based drilling fluids by these technologies at offshore drilling sites and on the issue of space constraints with regard to installing these systems at offshore facilities.

The Agency solicits comment on the model drilling scenarios selected for analysis, the costs to implement the treatment technologies and treatment methods discussed in this part, and on any actual and foreseeable problems regarding adequate onshore disposal sites for drilling wastes. The Agency also invites comment on the extent to which the oil content and the toxicity of drill cuttings and drilling fluids is due to downhole contamination. The Agency also invites comment on the applicability of these technologies to drilling wastes from Alaskan coastal and offshore facilities.

Some of the technologies discussed in this part of today's notice have air emissions associated with the operation of the processes. The Agency has obtained some air emissions characterization data on these technologies, but does not have sufficient information to properly consider the non-water quality aspects of these technologies. The Agency solicits additional emissions characterization data from the operation of these technologies.

As indicated by the analytical method for oil content determinations presented in Appendix A of today's notice, the Agency's preferred method for oil content determinations for wastes containing high solids content (*i.e.*, drill cuttings, drilling fluids) is the "retort-gravimetric" method. The Agency requests that any commenters that intend to supply the Agency with performance data on drilling fluid or drill cuttings treatment technologies provide oil content determinations based upon the retort-gravimetric method presented in Appendix A below.

Appendix A—Proposed Method 1651—Oil Content and Diesel Oil in Drilling Muds and Drill Cuttings by Retort Gravimetry and GCFID

1 Scope and Application

- 1.1 This method is used to determine the oil content and the identity and concentration of diesel oil in drilling fluid (mud) samples. It is applicable to all mud types and may also be used to determine the oil content and diesel oil in drill cuttings.
 - 1.2 This method may be used for compliance monitoring purposes as part of the "Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category".
 - 1.3 When this method is used to analyze samples for which there is no reference diesel oil, diesel oil identification should be supported by at least one additional qualitative technique. Methods 625 and 1625 provide gas chromatograph/mass spectrometer (GC-MS) conditions appropriate for the qualitative and quantitative confirmation of the presence of the components of diesel oil (references 1-2).
 - 1.4 The detection limit of this method is usually dependent upon the presence of other oils in the sample. Excluding interferences, estimated detection limits of 200 mg/kg of oil content and 100 mg/kg of diesel oil can be obtained.
 - 1.5 Any modification of this method beyond those expressly permitted shall be considered as a major modification subject to application and approval of alternate test procedures under 40 CFR 136.4 and 136.5.
 - 1.6 The gas chromatography portions of this method are restricted to use by or under the supervision of analysts experienced in the use of gas chromatograms. Each laboratory that uses this method must generate acceptable results using the procedures described in sections 8.2 and 12 of this method.
- ### 2 Summary of Method
- 2.1 A weighed amount of drilling mud is distilled using a retort apparatus. The distillate is extracted with methylene chloride and the extract is dried by passage through sodium sulfate. The extract is evaporated to dryness, and the total amount of oil is redissolved in methylene chloride, an internal standard is added, and an aliquot is injected into a gas chromatograph (GC). The

components of the oil are separated by the GC and detected using a flame ionization detector (FID).

- 2.2 Identification of diesel oil (qualitative analysis) is performed by comparing the pattern of GC peaks (retention times and intensities) from the sample extract with the pattern of GC peaks from a reference diesel oil sample. Identification of diesel oil is established when the reference diesel and sample patterns agree per the criteria in this method.
 - 2.3 Quantitative analysis of diesel oil is performed using an internal standard technique.
- ### 3 Contamination and Interferences
- 3.1 Solvents, reagents, glassware and other sample processing hardware may yield artifacts and/or elevated baselines causing misinterpretation of chromatograms. All material shall be demonstrated to be free from interferences under the conditions of the analysis by running method blanks initially and with set of samples. Specific selection of reagents and purification of solvents by distillation in all-glass systems may be required. Glassware and, where possible, reagents are cleaned by solvent rinse or baking at 450 degree C for one hour minimum.
 - 3.2 There is no standard diesel oil. Oil components, as seen by GC-FID, will differ depending upon the oil source, the production date, production process, and the producer. In addition, there are three basic types of diesel oils: ASTM Designations No. 1-D, No. 2-D, and No. 4-D. The No. 2-D is most common "diesel oil"; however, No. 2-D is sometimes blended with No. 1-D which has a lower boiling range. For rigorous identification and quantification of diesel oil in a drilling fluid sample by GC-FID, the chromatographic pattern from the diesel oil should be matched with the chromatographic pattern from a reference standard of the same diesel oil suspected to be in the sample.
 - 3.3 To aid in the identification of interferences, the chromatographic pattern from a reference sample of drilling fluid prior to use is compared to the chromatographic pattern of the drilling fluid after use. An interference is present when the pattern of the background oil does not match, but contributes substantially to, the pattern of the diesel oil in the sample.

- 3.4 Mineral oils are often added to drilling fluids for lubricity. These oils when examined by GC-FID, contain some components common to diesel oil but have chromatographic patterns that are distinctly different from diesel oil. The analyst must first determine if the sample chromatogram shows the presence of diesel, mineral, or a combination of both before reliable quantification can be performed. This method permits selection of GC peaks unique to diesel oil for determination of diesel oil in the presence of mineral oil.
- 4 Safety
- 4.1 The toxicity or carcinogenicity of each reagent used in this method has not been defined. Therefore, each chemical compound should be treated as a potential health hazard. From this viewpoint, exposure to these chemicals must be reduced to the lowest possible level by whatever means available. The laboratory is responsible for maintaining a current awareness file of OSHA regulations regarding the safe handling of the chemical specified in this method. A reference file of material handling data sheets should also be made available to all personnel involved in the chemical analysis. Additional references to laboratory safety are available and have been identified (references 3-5) for the information of the analyst.
- 4.2 Methylene chloride has been classified as a known health hazard. All steps in this method which involve exposure to this compound shall be performed in an OSHA approved fume hood.
- 5 Apparatus and Materials
- 5.1 Sample bottles for discrete sampling
- 5.1.1 Bottle—4 oz Bosxtion round wide mouth jar with Teflon lined screw cap (Sargent Welsh S-9184-72CA, or equivalent). New bottles are used as received with no further cleaning required.
- 5.1.2 Bottle mailer—to fit bottles above (Sargent-Welsh 2306, or equivalent).
- 5.2 Distillation Apparatus
- 5.2.1 Retort—20 mL retort apparatus (IMCO Services Model No. R2100 or equivalent).
- 5.2.2 Glass wool—Pyrex (Corning 3950, or equivalent). Solvent extracted or baked at 450 degrees C for one hour minimum.
- 5.3 Extraction/drying apparatus
- 5.3.1 Separatory funnel—60 mL with Teflon stopcock
- 5.3.2 Drying column—400 mm x 15 to 20 mm i.d. Pyrex chromatographic column equipped with coarse glass frit or glass wool plug.
- 5.3.3 Glass filtering funnel—crucible holder (Corning No. 9480, or equivalent).
- 5.3.4 Spatulas—stainless steel or Teflon
- 5.4 Evaporation/concentration apparatus
- 5.4.1 Kuderna-Danish (K-D) apparatus
- 5.4.1.1 Evaporation flask—500 mL (Kontes K-570001-0500, or equivalent), attached to concentrator tube with springs (Kontes K-662750-0012).
- 5.4.1.2 Concentrator tube—10 mL, graduated (Kontes K-570050-1025, or equivalent) with calibration verified. Ground glass stopper (size 19/22 joint) is used to prevent evaporation of extracts.
- 5.4.1.3 Snyder column—three ball macro (Kontes K-503000-0232, or equivalent).
- 5.4.1.4 Snyder column—two ball micro (Kontes K-469002-0219, or equivalent).
- 5.4.1.5 Boiling chips
- 5.4.1.5.1 Glass or silicon carbide—approx 10/40 mesh, extracted with methylene chloride and baked at 450 degrees C for one hr minimum.
- 5.4.1.5.2 Teflon (optional)—extracted with methylene chloride.
- 5.4.2 Water bath—heated, with concentric ring cover, capable of temperature control (+/- 2 degrees C), installed in a fume hood.
- 5.4.2 Sample vials—amber glass, 1 — 5 mL with Teflon-lined screw or crimp cap, to fit GC autosampler.
- 5.5 Balances
- 5.5.1 Analytical—capable of weighing 0.1 mg. Calibration must be verified with class S weights each day of use.
- 5.5.2 Top loading—capable of weighing 10 mg.
- 5.6 Gas Chromatograph (GC)—analytical system with split injection, capillary column, temperature program with initial and final isothermal holds, and all required accessories including syringes, analytical columns, gases, detector, and recorder. The analytical system shall meet the performance specifications in section 12.
- 5.6.1 Column—30 +/- 5 m x 0.25 +/- 0.02 mm i.d., 99% methyl, 1% vinyl, 1.0 um film thickness, bonded phase fused silica capillary (Supelco SPB-1, or equivalent).
- 5.6.2 Detector—flame ionization. This detector has proven effective in the analyses of drilling fluids for diesel oil, and was used to develop the method performance statements in section 16. Guidelines for using alternate detectors are provided in section 11.1.
- 5.7 GC Data system—shall collect and record GC data, store GC runs in magnetic memory or on magnetic disk or tape, process GC data, compute peak areas, store calibration data including retention times and response factors, identify GC peaks through retention times, and compute concentrations
- 5.7.1 Data acquisition—GC data shall be collected continuously throughout the analysis and stored on a mass storage device.
- 5.7.2 Response factors and calibration curves—the data system shall be used to record and maintain lists of response factors, and multi-point calibration curves (section 7). Computations of relative standard deviation (coefficient of variation; CV) are used for testing calibration linearity. Statistics on initial (section 8.2) and on-going (section 12.5) performance shall be computed and maintained.
- 5.7.3 Data processing—the data system shall be used to search, locate, identify, and quantify the compounds of interest in each GC analysis. Software routines shall be employed to compute and record retention times and peak areas. Displays of chromatograms and library comparisons are required to verify results.
- 6 Reagents
- 6.1 Sodium sulfate—anhydrous, (ACS) granular.
- 6.2 Methylene chloride—Nanograde or equivalent.
- 6.3 Reagent water—water in which the compounds of interest and interfering compounds are not detected by this method.
- 6.4 Internal standard—dissolve 1.0 g of 1,3,5-Trichlorobenzene (Kodak No. 1801 or equivalent) in 100 mL methylene chloride. Store in glass and tightly cap with Teflon lined lid to prevent loss of solvent by evaporation. Label with the concentration and date. Mark the level of the meniscus on the bottle to detect solvent loss.
- 6.5 Calibration standards—calibration standards are prepared from the same diesel oil expected to be in the sample; otherwise, No. 2 diesel oil is used. Calibration standards are prepared at the concentrations shown in table 1.
- 6.5.1 Weigh the appropriate amount of oil into a tared 10 mL volumetric flask and dilute to volume with methylene chloride. Calibration

standards are made fresh daily to avoid solvent loss by evaporation.

6.5.2 Using a micropipet or microsyringe, transfer 100 μ L of each reference standard solution (Section 6.5.1) to a GC injection vial. Add 100 μ L of the TCB internal standard (6.4) to each vial and mix thoroughly.

6.6 QC standard—used for tests of initial (section 8.2) and ongoing (section 12.5) performance. A reference drilling fluid known to contain 10,000–50,000 mg/kg of diesel oil is used, if available. If a reference drilling fluid is not available, a solution containing 600 mg/mL of No. 2 diesel oil in methylene chloride is used.

7 Calibration

7.1 Establish gas chromatographic operating conditions given in Table 2. Verify that the GC meets the performance criteria in section 12 and that the EDL given in section 1.4 can be achieved. The gas chromatographic system is calibrated using the internal standard technique.

7.2 Internal standard calibration procedure—1,3,5-Trichlorobenzene (TCB) has been shown to be free of interferences from the diesel oils tested in the development of this method. However, if an interference is known or suspected, the analyst must choose an alternate internal standard that is free from interferences.

7.2.1 Inject 1 μ L of each reference oil standard containing the internal standard (table 1 and section 6.5.2) into the GC-FID. The TCB will elute approx. 8.5 minutes after injection. For the CG-FID used in the development of this method, the TCB internal standard peak was 30–50 percent of full scale at an attenuator setting of 8E–11 amp.

7.2.2 Individual response factors

7.2.2.1 Tabulate the peak area responses against concentration for each n-alkane peak listed in table 3 and for the internal standard. Calculate response factors (RF) for

each n-alkane peak using the following equation:

Equation 1:

$$RF = \frac{(As) (Cis)}{(Ais) (Cs)}$$

where:

As=Area of the peak to be measured.
Ais=Area of the internal standard peak.
Cs=Concentration of the peak to be measured (mg/kg).
Cis=Concentration of the internal standard (mg/kg).

7.2.2.2 If the RF is constant (<10% CV) over the calibration range (table 1), the RF can be assumed to be invariant and the average RF can be used for calculations. Alternatively, the results can be used to plot a calibration curve of response ratios, As/Ais, vs RF.

7.2.2.3 Calibration verification—the average RF or a point on the calibration curve shall be verified on each working day by the measurement of one or more calibration standards. If the RF for any peak varies from the RF obtained in the calibration by more than +/– 15 percent, the test shall be repeated using a fresh calibration standard. Alternatively, a new calibration curve shall be prepared.

7.2.3 Combined response factor—to reduce the error associated with the measurement of a single n-alkane peak, a combined response factor is used for computation of the diesel oil concentration. This combined response factor is the sum of individual response factors as given in equations 2 or 3:

Equation 2:

$$RF_{\text{combined}} = \frac{[RF(1)+RF(2) \dots +RF(n)] (Cis)}{(Cs)}$$

Equation 3:

$$RF_{\text{combined}} = \frac{[As(1) + As(2) \dots + As(n)] (Cis)}{(Ais) (Cs)}$$

where:

As(1) * * * * A(n) are the areas of the individual peaks.

8. Quality assurance/quality control.

8.1 Each laboratory that uses this method is required to operate a formal quality assurance program (reference 6). The minimum requirements of this program consist of an initial demonstration of laboratory capability, an ongoing analysis of standards and blanks as a test of continued performance, analyses of spiked samples to assess accuracy, and analysis of duplicates to assess precision. Laboratory performance is compared to established performance criteria to determine if the results of analyses meet the performance characteristics of the method.

8.1.1 The analyst shall make an initial demonstration of the ability to generate acceptable accuracy and precision with this method. This ability is established as described in section 8.2.

8.1.2 The analyst is permitted to modify this method to improve separations or lower the costs of measurements, provided all performance requirements are met. Each time a modification is made to the method, the analyst is required to achieve the EDL (section 1.4) and to repeat the procedure in section 8.2 to demonstrate method performance.

8.1.3 Analyses of blanks are required to demonstrate freedom from contamination. The procedures and criteria for analysis of a blank are described in section 8.5.

8.1.4 The laboratory shall, on an ongoing basis, demonstrate through calibration verification and the analysis of the QC standard (section 6.6) that the analysis system is in control. These procedures are described in section 12.

8.1.5 The laboratory shall maintain records to define the quality of data that is generated. Development of

- accuracy statements is described in sections 8.3.4 and 12.5.
- 8.2 Initial precision and accuracy—to establish the ability to generate acceptable precision and accuracy, the analyst shall perform the following operations:
- 8.2.1 Retort, extract, concentrate, and analyze four samples of the QC standard (section 6.6 and 10.1.3) according to the procedure beginning in section 10.
- 8.2.2 Using results of the set of four analyses, compute the average recovery (X) in mg/kg and the standard deviation of the recovery (s) in mg/kg for each sample by the internal standard method (sections 7.2 and 14.2).
- 8.2.3 For each compound, compare s and X with the corresponding limits for initial precision and accuracy in table 4. If s and X meet the acceptance criteria, system performance is acceptable and analysis of samples may begin. If however, s exceeds the precision limit or X falls outside the range for accuracy, system performance is unacceptable. In this event, correct the problem, and repeat the test.
- 8.3 Method accuracy—the laboratory shall spike a minimum of 20 percent (one sample in each set of five samples) of all drilling fluid samples. This sample shall be spiked with the diesel oil that was added to the drilling fluid. If a reference standard of diesel oil that was added to the drilling fluid is not available, No. 2 diesel oil shall be used for this spike. If doubt of the identity and concentration of diesel oil in any of the remaining 80 percent of the samples exists, that sample shall be spiked to confirm the identity and establish the diesel oil concentration.
- 8.3.1 The concentration of the spike in the sample shall be determined as follows:
- 8.3.1.1 If, as in compliance monitoring, the concentration of the oil in the sample is being checked against a regulatory concentration limit, the spike shall be at that limit or at one to five times higher than the background concentration determined in section 8.3.2, whichever concentration is larger.
- 8.3.1.2 If the concentration of the oil in a sample is not being checked against a limit, the spike shall be at the concentration of the QC standard (section 6.6) or at one to five times higher than the background concentration, whichever concentration is larger.
- 8.3.2 Analyze one sample aliquot to determine the background concentration (B) of oil content and of diesel oil. If necessary, prepare a standard solution appropriate to produce a level in the sample at the regulatory concentration limit or at one to five times the background concentration (per section 8.3.1). Spike a second sample aliquot with the standard solution and analyze it to determine the concentration after spiking (A) of each analyte. Calculate the percent recovery (P) of oil content and of diesel oil:
- $$P = 100 (A - B) / T$$
- where T is the true value of the spike.
- 8.3.3 Compare the percent recovery for oil content and for diesel oil with the corresponding QC acceptance criteria in table 4. If the results of the spike fail the acceptance criteria, and the recovery of QC standard in the on-going precision and recovery test (sections 10.1.3 and 12.5) is within the acceptance criteria in table 4, an interference may be present (see sections 3 and 15 for identification of interferences). If, however, the results of both the spike and the on-going precision and recovery test fail the acceptance criteria, the analytical system is judged to be out of control and the problem must be immediately identified and corrected, and the sample reanalyzed.
- 8.3.4 As part of the QA program for the laboratory, method accuracy for samples shall be assessed and records shall be maintained. After the analysis of five spike samples in which the recovery passes the test in section 8.3, compute the average percent recovery (P) and the standard deviation of the percent recovery (sp). Express the accuracy assessment as a percent recovery interval from $P - 2sp$ to $P + 2sp$. For example, if $P = 90\%$ and $sp = 10\%$ for five analyses of diesel oil, the accuracy interval is expressed as 70—110%. Update the accuracy assessment on a regular basis (e.g. after each 5—10 new accuracy measurements).
- 8.4 The laboratory shall analyze duplicate samples for each drilling fluid type at a minimum of 20 percent (one sample for each five sample set). A duplicate sample shall consist of a well-mixed, representative aliquot of the sample.
- 8.4.1 Analyze one sample in the set in duplicate per the procedure beginning in section 10.
- 8.4.2 Compute the relative percent difference (RPD) between the two results per the following equation: Equation 4:
- $$RPD = \frac{(D1 - D2)}{(D1 + D2)/2} \times 100$$
- where:
 D1 = concentration of diesel in the sample
 D2 = concentration of diesel oil in the second (duplicate) sample
- 8.4.3 The relative percent difference for duplicates shall meet the acceptance criteria in table 5. If the criteria are not met, the analytical system shall be judged to be out of control, and the problem must be immediately identified and corrected, and the sample set reanalyzed.
- 8.5 Blanks—reagent water blanks are analyzed to demonstrate freedom from contamination.
- 8.5.1 Extract and concentrate a reagent water blank initially and with each sample set (samples started through the analysis on the same day, to a maximum of 5 samples). Analyze the blank immediately after analysis of the QC standard (section 6.6) to demonstrate freedom from contamination.
- 8.5.2 If any of the components of diesel oil or any potentially interfering compound is detected in a blank, analysis of samples is halted until the source of contamination is eliminated and a blank shows no evidence of contamination.
- 8.6 Comparison of gravimetric and diesel oil measurements.
- 8.6.1 Compare the concentration of the oil content (14.1.2) determined gravimetrically with the diesel oil concentration determined by GC/FID (14.2.2). If the diesel oil concentration exceeds the gravimetric oil concentration, the analysis has been performed improperly. Correct the error or repeat the sample analysis beginning with section 10.
- 8.7 The specifications contained in this method can be met if the apparatus used is calibrated properly, then maintained in a calibrated state. The standards used for calibration (section 6.4), calibration verification (section 7.3), and for initial (section 8.2) and on-going (section 12.5) precision and recovery should be

- identical, so that the most precise results will be obtained. The GC instrument will provide the most reproducible results if dedicated to the settings and conditions required for the analyses of the analyte given in this method.
- 8.8 Depending on specific program requirements, field replicates and field spikes of diesel oil into samples may be required to assess the precision and accuracy of the sampling and sample transporting techniques.
- 9 Sample Collection, Preservation, and Handling
- 9.2 Collect samples in glass containers following conventional sampling practices (reference 7). Drilling fluid samples are collected in wide-mouth jars.
- 9.2 Samples must be representative of the entire bulk drilling fluid. In some instances, composite samples may be required.
- 9.3 Maintain samples at 0—4 degrees C from the time of collection until extraction.
- 9.4 Sample and extract holding times for this method have not yet been established. However, based on tests of wastewater for the analytes determined in this method, samples shall be extracted within seven days of collection and extracts shall be analyzed within 40 days of extraction.
- 9.5 As a precaution against analyte and solvent loss or degradation, sample extracts are stored in glass bottles with Teflon lined caps, in the dark, at -20 to -10 degrees C.
- 10 Sample extraction and concentration
- 10.1 Retort
- 10.1.1 Tare the retort sample cup and cap to the nearest 0.1 gm. Transfer a well homogenized and representative portion of the drilling fluid to be tested into the sample cup. Do not fill the retort cup to the top so that excess sample must be wiped off. Place the cap on the cup and reweigh. Record the weight of the sample to the nearest 0.1 g.
- Note: on agitation, most drilling fluids entrain air as small bubbles. The extent of air entrainment is uncertain and is difficult to detect when the mud is poured into the retort cup. By weighing the drilling fluid, the quantitative detection of diesel oil is improved. In addition, by using a gravimetric measurement of the amount of sample, the retort cup does not need to be completely filled. This procedure avoids the error that occurs when the cup is filled and the oil rises to the surface of the sample and must be wiped off (as occurs if the manufacturer's instructions are followed), thus resulting in a loss of oil.
- 10.1.2 Follow the manufacturer's instructions for retort of the drilling fluid. Substitute 6 g of loosely packed glass wool for the steel wool in the manufacturer's instructions and distill the sample into a glass receiver. The presence of solids in the distillate require that the distillation be rerun starting with a new portion of sample. Placing more glass wool in the retort expansion chamber, per the manufacturer's instructions, will help prevent the solids from being carried over in the distillation.
- 10.1.3 QC standard—used for tests of initial (section 8.2) and on-going (section 12.5) precision and accuracy. For the initial set of four samples (section 8.2) and for each set of samples started through the retort process on the same working day (to a maximum of five), prepare a QC sample as follows:
- 10.1.3.1 Place the reference drilling fluid containing 10,000—50,000 mg/kg of diesel oil (section 6.6) in the retort cup beginning in section 10.1.
- 10.1.3.2 Alternatively, pipet 1.00 mL of the solution containing 600 mg/mL of diesel oil in methylene chloride into a clean retort cup and weigh to the nearest mg. Record the weight of the oil to the nearest mg. Add approximately 10 mL of reagent water to the cup and place the cap on the cup.
- 10.1.3.3 Analyze the QC standard beginning with section 10.1.2 then proceeding to section 10.2
- 10.1.4 Blank—For the initial set of four samples (section 8.2) and for each set for samples started through the retort process on the same working day (to a maximum of five), prepare a blank as follows:
- 10.1.4.1 Place 10 mL of reagent water in a clean, tared, retort cup and weigh to the nearest mg. Record the weight of the reagent water.
- 10.1.4.2 Analyze the blank beginning with section 10.1.2 then proceeding to section 10.2.
- 10.2 Extraction and drying
- 10.2.1 After the distillation is complete, pour the retort distillate into a 60 mL separatory funnel. Quantitatively rinse the inner surfaces of the retort stem and condenser with methylene chloride into the separatory funnel. Rinse the receiver with two full receiver volumes of methylene chloride and add to the separatory funnel.
- 10.2.2 Stopper and shake the funnel for one minute, with periodic venting to prevent a build up of gas pressure. Allow the layers to separate.
- 10.2.2 Prepare a glass filtering funnel by plugging the bottom with a piece of glass wool and pouring in 1—2 inches of anhydrous sodium sulfate. Wet the funnel with a small portion of methylene chloride and allow the methylene chloride to drain to a waste container. Alternatively, a drying column may be used.
- 10.2.3 Place the glass filtering funnel or drying column into the top of a Kuderna-Danish (K-D) flask equipped with a preweighed 10 mL receiving flask. Add a preweighed boiling chip to the receiving flask. Drain the methylene chloride (lower) layer into the glass filtering funnel or drying column, and collect the extract in the K-D flask.
- 10.2.4 Repeat the methylene chloride extraction twice more, rinsing the retort with two thorough washings each time and draining each methylene chloride extract through the funnel or drying column into the K-D flask.
- 10.3 Concentration
- 10.3.1 Place a Snyder column on the K-D flask. Prewet the Snyder column by adding about one mL methylene chloride to the top. Place the K-D apparatus on a hot water bath (60—65 degrees C) so that the concentrator tube is partially immersed in the hot water, and the entire lower rounded surface of the flask is bathed with hot vapor. Adjust the vertical position and the water temperature as required to complete the concentration in 15—20 minutes. At the proper rate of distillation, the balls of the column will actively chatter but the chambers will not flood with condensed solvent. Concentrate the sample until it is free of methylene chloride. Remove the K-D apparatus from the hot water bath and allow to cool.
- 10.3.2 Weigh and record the final weight of the receiving flask.
- 10.3.3 Dissolve the oil in methylene chloride and adjust the final volume to 1.0 mL. If the extract did not concentrate to a final volume of 1.0 mL or less, adjust the final volume to 10.0 mL.
- 11 Gas chromatography
- 11.1 Table 3 lists the retention times that can be achieved under the conditions in table 2 for the n-alkanes of interest. Examples of separations that can be achieved

- are shown in figure 1.¹ Other retort devices, columns, chromatographic conditions, or detectors may be used if the EDL stated in this method and the requirements of section 8.2 are met.
- 11.2 Using a micropipet or microsyringe, transfer equal 100 μL volumes of the sample extract or QC standard extract (section 10.3.3) and the TCB internal standard solution (section 6.4) into a GC injection vial. Cap tightly and mix thoroughly.
- 11.3 Inject 1 μL of the sample extract or reference standard into the GC using the conditions in table 2.
- 11.4 Begin data collection and the temperature program at the time of injection.
- 11.5 If the area of any peak exceeds the calibration range of the system, make a 10-fold dilution of the extract (section 10.3.3), mix a 100 μL aliquot of this dilute extract with 100 μL of the internal standard solution (section 6.4), and reanalyze.
- 12 System and laboratory performance
- 12.1 At the beginning of each working day during which analyses are performed, GC calibration is verified. For these tests, analysis of the 300 mg/mL calibration standard (table 1) shall be used to verify all performance criteria. Adjustment and/or recalibration (per section 7) shall be performed until all performance criteria are met. Only after all performance criteria are met may the QC standard and samples be analyzed.
- 12.2 Retention times
- 12.2.1 Retention time of the internal standard—the absolute retention time of the TCB internal standard shall be within the range of 7.96–8.08 minutes.
- 12.2.2 Relative retention times of the n-alkanes—the retention times of the n-alkanes relative to the TCB internal standard shall be within the limits given in table 4.
- 12.3 Calibration verification
- 12.3.1 Compute the response factor for each n-alkane by the internal standard technique (section 7.2).
- 12.3.2 For each n-alkane, compare the response factor with the response factor from the initial calibration (section 7.2.2). If all response factors are within ± 15 percent of their respective values in the calibration data, system calibration has been verified. If not, prepare a fresh calibration standard and repeat the test (section 12.1), or recalibrate (section 7).
- 12.4 Multiple GC peaks—each n-alkane shall give a single, distinct GC peak.
- 12.5 On-going precision and accuracy
- 12.5.1 Compute the oil content concentration and the concentration of diesel oil in the QC standard in each sample set (section 10.1.3) prior to analysis of any sample in the set.
- 12.5.2 Compare the concentration with the QC limit in table 4. If the concentrations of oil content and of diesel oil in the QC standard meet the acceptance criteria, system performance is acceptable and analysis of samples may proceed. If, however, the concentrations do not meet the acceptance criteria, system performance is unacceptable. In this event, correct the problem, reprocess the sample set (section 10), and repeat the on-going precision and accuracy test (sections 10.1.3 and 12.5).
- 12.5.3 Add results that pass the specifications in section 12.5.2 to initial and previous on-going data. Update QC charts to form a graphic representation of continued laboratory performance. Develop statements of laboratory accuracy for oil content and diesel oil in drilling fluids by accuracy for oil content and diesel oil in drilling fluids by calculating the average percent recovery (R) and the standard deviation of percent recovery (sr). Express the accuracy statement as a recovery interval from $R - 2$ sr to $R + 2$ sr. For example, if $R = 95$ percent and $sr = 5$ percent, the accuracy is 85–105 percent.
- 13 Qualitative determination
- 13.1 Compare the sample chromatogram to the chromatogram of the standard. If the sample contains diesel oil, the major peaks present in the standard (n-alkanes) will also be present in the sample and have the same relative intensity and pattern (see figure 1).
- 13.2 Relative retention times—the major n-alkane peaks (table 3) shall be present and shall be within the limits in table 3.
- 13.3 Some mineral oil lubricity additives have similar chromatographic patterns to that of diesel oil. The presence of early, smaller peaks with retention times in the range of one to four minutes will differentiate between distillates containing only mineral oil and those with diesel oil.
- 14 Quantitative determination
- 14.1 Oil content by gravimetry
- 14.1.1 Subtract the weight of the preweighed receiving flask and boiling chip (10.2.3) from the final weight of the receiving flask (10.3.2).
- 14.1.2 Calculate the concentration of oil in the sample using the following equation:
- Equation 7:
- $$C \text{ (mg/kg)} = \frac{W_f}{W_s} \times 100$$
- where:
 W_f = final weight of oil in mg (from 14.1.1)
 W_s = wet weight of sample in grams (from 10.1.1)
- 14.2 Diesel oil by gas chromatography
- 14.2.1 Compute the concentration of diesel oil in the sample extract using the combined response factor given in section 7.3.3 and either of the following equations:

Equation 5:

$$\text{Cex (mg/mL)} = (\text{Cis}) \frac{[\text{RF}(1) + \text{RF}(2) : \dots + \text{RF}(n)]}{(\text{RF combined})}$$

¹ Figure 1—Sample Chromatograms, is not published in the Federal Register but is available in the public docket. See "Addresses" section.

Equation 6:
$$C_{ex} \text{ (mg/mL)} = (C_{is}) \frac{[As(1) + As(2) \dots + As(n)]}{(A_{is}) \text{ (RF combined)}}$$

where:
 C_{ex} is the concentration of the oil in the extract
 14.2.2 Calculate the concentration of diesel oil (in mg/kg) in the sample as follows:

Equation 6:

$$C \text{ (mg/kg)} = \frac{(C_{ex}) (V_{ex})}{(W_s)} \times 100$$

where:
 V_{ex} = final extract volume in mL (from 10.3.3 or 14.2.3)
 W_s = wet weight of sample in grams (from 10.1.1)

14.2.3 If area of any peak in the chromatographic pattern exceeds the calibration range of the GC, the extract is diluted by a factor of 10 with methylene chloride, 100 µL is withdrawn and mixed with 100 µL of the internal standard solution (section 6.4) and the diluted extract is reanalyzed.

14.3 Results of analyses of drilling fluids are reported in units of mg/kg (wet weight) to three significant figures. Results for samples that have been diluted are reported at the least dilute level at which the peak areas are within the calibration range (section 14.2.3).

15 Complex samples

15.1 The most common interference in the determination of diesel oil is from mineral oil in the drilling fluid (see sections 3 and 13). Drilling fluids may also contain proprietary lubricity additives that can interfere with the identification and quantification of diesel oil.

15.2 The presence of mineral oil or other interfering oils and additives can often be determined by comparing the pattern of chromatographic peaks in the sample with the patterns of chromatographic peaks in the reference standard (sections 6.5 and 10.1.3) and in the spiked sample (section 8.3).

15.3 In cases where there is a mixture of diesel and mineral oil, the analyst may have to choose some of the smaller early or late eluting peaks present in the chromatographic pattern of the diesel oil, and not present in the chromatographic pattern of the

mineral oil, to determine the diesel content. Quantification using these peaks is performed by using these peaks for calibration (section 7) and for determination of the final concentration (section 14).

15.4 In extreme cases, the method of standard additions may be required to reliably quantitate the diesel content of a sample containing interferences.

16 Method performance

16.1 This method was developed by two laboratories that tested for diesel oil in drilling fluids (mainly drilling muds) over a two-year period. The performance data for this method is based on the performance of the method in these two laboratories (reference 8).

16.2 The most commonly occurring drilling fluid in the tests of this method was a seawater lignosulfonate mud (EPA Generic Mud No. 8). The estimated detection limit for diesel oil in this mud is 100 µg/kg.

References

1. Brown, John S, "Organic Chemical Characterization of Diesel and Mineral Oils Used as Drilling Mud Additives", Proceedings of Tenth Annual Analytical Symposium, USEPA, Industrial Technology Division (WH-552), 401 M St, Washington DC 20460, March 19-20 1986.
2. Brown, John S, "Final Report for Research Program on: Organic Chemical Characterization of Diesel and Mineral Oils used as Drilling Mud Additives", Phase II, Contract Reference Agreement No. 501-P-5476R, to Offshore Operators Committee, Environmental Subcommittee, Houston, TX, Prepared by Battelle Ocean Science and Technology Department, 397 Washington St, Duxbury MA 02332.
3. "Carcinogens—Working With Carcinogens", Department of Health, Education, and Welfare, Public Health Service, Center for Disease Control, National Institute for Occupational Safety and Health, Publication No. 77-208, August 1977.
4. "OSHA Safety and Health Standards, General Industry", [29 CFR 1910]. Occupational Safety and Health Administration, OSHA 2206 (Revised, January 1976).
5. "Safety in Academic Chemistry Laboratories", American Chemical Society Publication, Committee Chemical Safety, 3rd Edition, 1979.
6. "Handbook of Analytical Quality Control in Water and Wastewater Laboratories", USEPA, EMSL, Cincinnati, OH 45268, EPA-600/4-79-019 (March 1979).

7. "Standard Practice for Sampling Water", ASTM Annual Book of Standards, ASTM, Philadelphia, PA 76 (1980).

8. Rushneck, D R, and Eynon B P, "Precision and Recovery Analysis of DPMP Diesel Measurements", Memorandum to Dennis Ruddy, USEPA, Industrial Technology Division (WH-552), 401 M St SW, Washington DC 20460 (23 August 1987, draft).

TABLE 1—CONCENTRATION OF CALIBRATION STANDARDS

Expected concentration in sample	Wt of Diesel oil in 10 mL volumetric ¹ (g)	Concentration in standard
50,000 mg/kg.....	Use undiluted oil.	
30,000 mg/kg.....	7.6.....	760 mg/mL
10,000 mg/kg.....	3.0.....	300 mg/mL
5,000 mg/kg.....	1.5.....	150 mg/mL
2,000 mg/kg.....	0.6.....	60 mg/mL

¹ Weigh oil to the nearest mg.

TABLE 2—GAS CHROMATOGRAPHIC OPERATING CONDITIONS—METHOD 1651¹

Injection port, transfer line, and detector temperatures = 275 C
 Column temperature program:
 Initial temperature: 90 C
 Initial time: 0 minutes
 Ramp: 90 - 250 C @ 5 C per min
 Final temperature: 250 C
 Final hold: 10 minutes or until all peaks have eluted.
 Carrier gas and flow rates:
 Carrier: nitrogen or helium
 Velocity: 20 - 40 cm/sec @ 90 C
 Split ratio: 80:1 - 120:1
 Makeup gas: as required by manufacturer
 Hydrogen and air flow rates: as specified by manufacturer
 Detector amplifier settings: 10-11 amp full scale.
 Attention is adjusted so that the highest peaks are on scale in the most concentrated standard.
 Recorder: Chart speed of 1 - 2 cm/min (fixed).
¹ Conditions are approximate and can be adjusted to meet the performance criteria in section 12.

TABLE 3.—RETENTION TIMES AND RELATIVE RETENTION TIME LIMITS FOR MAJOR COMPONENTS OF DIESEL OIL—METHOD 1651

Compound	Retention time	
	Mean	Relative
TCB.....	8.0	1.00-1.00
n-C12.....	9.9	1.22-1.24
n-C14.....	12.6	1.55-1.57
n-C16.....	15.3	1.98-1.92
n-C18.....	17.9	2.21-2.25
n-C20.....	20.4	2.52-2.56
n-C22.....	22.9	2.82-2.88
n-C24.....	25.2	3.12-3.15

TABLE 4—QC ACCEPTANCE CRITERIA FOR PRECISION AND RECOVERY—METHOD 1651¹

Analyte	Test concentration (mg/kg)	Limit for s (mg/kg)	Range for X (mg/kg)	Range for P (mg/kg)
Oil Content by grav	20,000 ¹ n	3,400 0.17n	18,000-23,700 0.88n-1.16n	16,700-24,900 0.82n-1.22n
Diesel oil by GC	20,000 ² n	3,600 0.18n	17,200-20,300 0.80n-1.08n	13,600-21,400 0.73n-1.14n

¹ Preliminary specifications; final specifications to be developed at a later date.

² For other test concentrations in the range of 1,000-50,000 mg/kg, assuming a spike to background ratio of 5:1.

Table 5—QC ACCEPTANCE CRITERIA FOR DUPLICATES—METHOD 1651

Concentration detected (mg/kg)	Relative percent oil content	Difference diesel oil
500	36	94
750	30	68
1,000	38	54
2,000	24	34
5,000	21	22
10,000	21	18
20,000	20	16
50,000	20	15

Dated: October 3, 1988.

William A. Whittington,

Acting Assistant Administrator for Water.

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BILLING CODE 6560-50-M

DEPARTMENT OF DEFENSE

48 CFR Parts 214 and 215

Department of Defense Federal Acquisition Regulation Supplement; Sealed Bidding

AGENCY: Department of Defense (DoD).

ACTION: Proposed rule and request for public comments.

SUMMARY: The Defense Acquisition Regulatory (DAR) Council is considering changes to the Defense Federal Acquisition Regulation Supplement (DFARS), Subpart 214.2 and 215.4 to delete this coverage as a result of recent recommendations to add similar coverage to the Federal Acquisition Regulation. The proposed additions to the Federal Acquisition Regulation are

also published in this issue of the Federal Register.

DATE: Comments on this proposed revisions should be submitted in writing to the Executive Secretary, DAR Council, at the address shown below, on or before December 20, 1988, to be considered in the formulation of the final rule. Please cite DAR Case 88-50 in all correspondence relating to this issue.

ADDRESS: Interested parties should submit written comments to: Defense Acquisition Regulatory Council, ATTN: Mr. Charles W. Lloyd, Executive Secretary, DAR Council, ODASD (P)/DARS, c/o OASD(P&L) (MRS), Room 3D139, The Pentagon, Washington, DC 20301-3062.

FOR FURTHER INFORMATION CONTACT: Mr. Charles W. Lloyd, Executive Secretary, DAR Council, (202) 697-7266.

SUPPLEMENTARY INFORMATION:

A. Background

The Defense Acquisition Regulatory Council has reviewed the DoD FAR Supplement and determined that the coverage at 214.270 and 215.470 is appropriate for inclusion in the Federal Acquisition Regulation.

B. Regulatory Flexibility Act

The proposed rule does not constitute a significant FAR revision within the meaning of FAR 1.501 and Pub. L. 98-577 and publication for public comment is not required. Master solicitations, in and of themselves are nothing more than a package of solicitations and clauses sent to contractors who are on bidders mailing lists and the package is referred to when an actual solicitation is issued.

Therefore, the Regulatory Flexibility Act does not apply. However, comments from small entities concerning the affected DFARS Subpart will also be considered in accordance with section 610 of the Act. Such comments must be submitted separately and cite DFARS Case 88-610D in correspondence.

C. Paperwork Reduction Act

The rule does not contain information collection requirements which require the approval of OMB under 44 U.S.C. 3501.

List of Subjects in 48 CFR Parts 214 and 215

Government procurement.

October 13, 1988.

Charles W. Lloyd,

Executive Secretary, Defense Acquisition Regulatory Council.

Therefore, it is proposed to amend 48 CFR Parts 214 and 215 as follows:

The authority citation for 48 CFR Parts 214 and 215 continues to read as follows:

Authority: 5 U.S.C. 301, 10 U.S.C. 2202, DoD Directive 5000.35, and DoD FAR Supplement 201.301.

PART 214—SEALED BIDDING

214.270 [Removed]

2. Section 214.270 is removed.

PART 215—CONTRACTING BY NEGOTIATION

215.470 [Removed]

3. Section 215.470 is removed.

[FR Doc. 88-24411 Filed 10-20-88; 8:45 am]

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