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40 CFR Part 435

Effluent Limitations Guidelines and New Source Performance Standards for Synthetic-Based and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 435

[FRL–6215–1]

RIN 2040–AD14

Effluent Limitations Guidelines and New Source Performance Standards for Synthetic-Based and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This proposed rule would amend the technology-based effluent limitations guidelines for the discharge of certain pollutants into waters of the United States by existing and new facilities in portions of the offshore and coastal subcategories of the oil and gas extraction point source category.

This proposed rule would establish effluent limitations guidelines and new source performance standards (NSPS) for direct dischargers based on ''best practicable control technology currently available'' (BPT), ''best conventional pollutant control technology'' (BCT), ''best available technology economically achievable'' (BAT), and for new sources ''best available demonstrated control technology'' (BADCT). EPA is proposing to amend the regulation by providing specific requirements for the discharge of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids. The wastestreams that would be limited are drilling fluids and drill cuttings.

This rule would not amend the current regulations for water-based drilling fluids. Also, this rule would not amend the zero discharge requirement for drilling wastes in the coastal subcategory (except Cook Inlet, Alaska) and in the offshore subcategory within three miles from shore.

Controlling the discharge of SBFs as proposed today would reduce the discharge of SBFs by 11.7 million pounds annually. Further, allowing rather than prohibiting the discharge of SBFs would substantially reduce non-water quality environmental impacts. Compared to the zero discharge option, EPA estimates that allowing discharge will reduce air emissions of the criteria air pollutants by 450 tons per year, decrease fuel use by 29,000 barrels per year of oil equivalent, and reduce the generation of oily drill cutting wastes requiring off-site disposal by 212 million pounds per year.

DATES: Comments on the proposal must be received by May 4, 1999. A public meeting will be held during the comment period, on Friday, March 5, 1999, from 9:00 a.m. to 12:00 p.m.

ADDRESSES: Send written comments and supporting data on this proposal to: Mr. Joseph Daly, Office of Water, Engineering and Analysis Division (4303), U.S. Environmental Protection Agency, 401 M St. SW, Washington, DC 20460. Please submit any references cited in your comments. EPA would appreciate an original and two copies of your comments and enclosures (including references).

The public meeting will be held at the EPA Region 6 Oklahoma Room, 1445 Ross Avenue, Dallas, TX. If you wish to present formal comments at the public meeting you should have a written copy for submittal. No meeting materials will be distributed in advance of the public meeting; all materials will be distributed at the meeting.

The public record is available for review in the EPA Water Docket, Room EB57, 401 M St. SW, Washington, DC 20460. The public record for this rulemaking has been established under docket number W–98–26, and includes supporting documentation, but does not include any information claimed as Confidential Business Information (CBI). The record is available for inspection from 9 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. For access to docket materials, please call (202) 260–3027 to schedule an appointment.

FOR FURTHER INFORMATION CONTACT: For additional technical information contact Mr. Joseph Daly at (202) 260–7186. For additional economic information contact Mr. James Covington at (202) 260–5132.

SUPPLEMENTARY INFORMATION:

Regulated Entities: Entities potentially regulated by this action include:

Category	Examples of regulated entities
Industry	Facilities engaged in the drilling of wells in the oil and gas industry in areas defined as ''coastal'' or ''offshore'' and discharging in geographic areas where drilling wastes are allowed for discharge (offshore waters beyond 3 miles from the shoreline, in any Alaska offshore waters with no 3-mile restriction, and the coastal waters of Cook Inlet, Alaska). Includes certain facilities covered under Standard Industrial Classification code 13 and North American Classification System codes 211111 and 213111.

The preceding table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in 40 CFR Part 435, Subparts A and D. If you have questions regarding the applicability of this action to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Supporting Documentation

The regulations proposed today are supported by several major documents:

1. ''Development Document for Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–98–021). Hereafter referred to as the SBF Development Document, the document presents EPA's technical conclusions concerning the proposal. This document describes, among other things, the data collection activities in support of the proposal, the wastewater treatment technology options, effluent characterization, estimate of costs to the industry, and estimate of effects on non-water quality environmental impacts.

2. ''Economic Analysis of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–98–020). Hereafter referred to as the SBF Economic Analysis, this document presents the analysis of compliance costs and/or savings; facility closures; changes in rate of return level. In addition, impacts on employment and affected communities, foreign trade, specific demographic groups, and new sources also are considered.

3. ''Environmental Assessment of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–98–019). Hereafter referred to as the SBF Environmental Assessment, the document presents the analysis of relative water quality impacts for each regulatory option. EPA describes the environmental characteristics of SBF drilling wastes, types of anticipated impacts, and pollutant modeling results for water

column concentrations, pore water concentrations, and human health effects via consumption of affected seafood.

All documents are available from the Office of Water Resource Center, RC–4100, U.S. EPA, 401 M Street SW, Washington, DC 20460; telephone (202) 260–7786 for the voice mail publication request. The Development Document can also be obtained through EPA's Home Page on the Internet, located at WWW.EPA.GOV/OST/GUIDE. The preamble and rule can also be obtained at this site.

Overview

This preamble includes a description of the legal authority for these rules; a summary of the proposal; background information on the industry and its processes; and a description of the technical and economic methodologies used by EPA to develop these regulations. This preamble also solicits comment and data on all aspects of this proposed rule. The definitions, acronyms, and abbreviations used in this notice are defined in Appendix A to the preamble.

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I. Legal Authority

These regulations are proposed under the authority of Sections 301, 304, 306, 307, 308, 402, and 501 of the Clean Water Act, 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

II. Purpose and Summary of the Proposed Regulation

A. Purpose of This Rulemaking

The purpose of this rulemaking is to amend the effluent limitations guidelines and standards for the control of discharges of certain pollutants associated with the use of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids in portions of the Offshore Subcategory and Cook Inlet portion of the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. The limitations proposed today apply to wastes generated when oil and gas wells are drilled using SBFs or other non-aqueous drilling fluids (henceforth collectively referred to simply as SBFs) in coastal and offshore regions in locations where drilling wastes may be discharged. The processes and operations that comprise the offshore and coastal oil and gas subcategories are currently regulated under 40 CFR Part 435, Subparts A (offshore) and D (coastal). EPA is proposing these amendments under the authority of the CWA, as discussed in Section I of this notice. The regulations are also being proposed pursuant to a Consent Decree entered in *NRDC et al.* v. *Browner,* (D.D.C. No. 89–2980, January 31, 1992) and are consistent with EPA's latest Effluent Guidelines Plan under section 304(m) of the CWA. (See 63 FR 47285, September 4, 1998.) The most recent existing effluent limitations guidelines were issued on March 4, 1993 (58 FR 12454) for the Offshore Subcategory and on December 16, 1996 (61 FR 66086) for the Coastal Subcategory. This proposed rule is referred to as the Synthetic-Based Drilling Fluids Guidelines, or SBF Guidelines, throughout this preamble.

Today's proposal presents EPA's preferred technology approach and several others that are being considered in the regulation development process. The proposed rule is based on a detailed evaluation of the available data acquired during the development of the proposed limitations. EPA welcomes comment on all options and issues and encourages commenters to submit additional data during the comment period. Also, EPA is willing to meet with interested parties during the comment period to ensure that EPA has the views of all parties and the best possible data upon which to base a decision for the final regulation. EPA emphasizes that it is soliciting comments on all options discussed in this proposal and that it may adopt any

such options or combination of options in the final rule.

B. Summary of Proposed SBF Guidelines

This summary section highlights key aspects of the proposed rule. The technology descriptions discussed later in this notice are presented in abbreviated form; more detailed descriptions are included in the *Development Document for Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category,* referred to hereafter as the ''SBF Development Document.''

EPA proposes to establish regulations based on the ''best practicable control technology currently available'' (BPT), ''best conventional pollutant control technology'' (BCT), ''best available technology economically achievable'' (BAT), and the best available demonstrated control technology (BADCT) for new source performance standards (NSPS), for the wastestream of synthetic-based drilling fluids and other non-aqueous drilling fluids, and cuttings contaminated with these drilling fluids.

For certain drilling situations, such as drilling in reactive shales, high angle and/or high displacement directional drilling, and drilling in deep water, progress with water-based drilling fluids (WBFs) can be slow, costly, or even impossible, and often creates a large amount of drilling waste. In these situations, the well is normally drilled with traditional oil-based drilling fluids (OBFs), which use diesel oil or mineral oil as the base fluid. Because EPA rules require zero discharge of these wastes, they are either sent to shore for disposal in non-hazardous oil field waste (NOW) sites or injected into disposal wells.

Since about 1990, the oil and gas extraction industry has developed many new oleaginous (oil-like) base materials from which to formulate high performance drilling fluids. A general class of these are called the synthetic materials, such as the vegetable esters, poly alpha olefins, internal olefins, linear alpha olefins, synthetic paraffins, ethers, linear alkyl benzenes, and others. Other oleaginous materials have also been developed for this purpose, such as the enhanced mineral oils and non-synthetic paraffins. Industry developed SBFs with these synthetic and non-synthetic oleaginous materials as the base fluid to provide the drilling performance characteristics of traditional OBFs based on diesel and mineral oil, but with lower environmental impact and greater worker safety through lower toxicity, elimination of polynuclear aromatic hydrocarbons (PAHs), faster biodegradability, lower bioaccumulation potential, and, in some drilling situations, less drilling waste volume. EPA believes that this product substitution approach is an excellent example of pollution prevention that can be accomplished by the oil and gas industry.

EPA intends that these proposed regulations control the discharge of SBFs in a way that reflects application of appropriate levels of technology, while also encouraging their use as a replacement to the traditional mineral oil and diesel oil-based fluids. Based on EPA's information to date, the record indicates that use of SBFs and discharge of the cuttings waste with proper controls would overall be environmentally preferable to the use of OBFs. This is because OBFs are subject to zero discharge requirements, and thus, must be shipped to shore for land disposal or injected underground, resulting in higher air emissions, increased energy use, and increased land disposal of oily wastes. By contrast, the discharge of cuttings associated with SBFs would eliminate those impacts. At the same time EPA recognizes that the discharge of SBFs may have impacts to the receiving water. Because SBFs are water non-dispersible and sink to the seafloor, the primary potential environmental impacts are associated with the benthic community. EPA's information to date, including limited seabed surveys in the Gulf of Mexico, indicate that the effect zone of the discharge of certain SBFs is within a few hundred meters of the discharge point and may be significantly recovered in one to two years. EPA believes that impacts are primarily due to smothering by the drill cuttings, changes in sediment grain size and composition (physical alteration of habitat), and anoxia (absence of oxygen) caused by the decomposition of the organic base fluid. The benthic smothering and changes in grain size and composition from the cuttings are effects that are also associated with the discharge of WBFs and associated cuttings.

Based on the record to date, EPA finds that these impacts, which are believed to be of limited duration, are less harmful to the environment than the non-water quality environmental impacts associated with the zero discharge requirement applicable to OBFs. Compared to the zero discharge option EPA estimates that allowing discharge will reduce air emissions of the criteria air pollutants by 450 tons per year, decrease fuel use by 29,000 barrels per year of oil equivalent, and reduce the generation of oily drill cutting wastes requiring off-site disposal by 212 million pounds per year. In addition, EPA estimates that compliance with these proposed limitations would result in a yearly decrease in the discharge of 11.7 million pounds of toxic and nonconventional pollutants in the form of SBFs. These estimates are based on the current industry practice of discharging SBF-cuttings outside of 3 miles in the Gulf of Mexico and no discharge of SBFs in any other areas, including 3 miles offshore of California and in Cook Inlet, Alaska.

As SBFs came into commercial use, EPA determined that the current discharge monitoring methods, which were developed to control the discharge of WBFs, did not appropriately control the discharge of these new drilling fluids. Since WBFs disperse in water, oil contamination of WBFs with formation oil or other sources can be measured by the static sheen test, and any toxic components of the WBFs will disperse in the aqueous phase and be detected by the suspended particulate phase (SPP) toxicity test. With SBFs, which do not disperse in water but instead sink as a mass, formation oil contamination has been shown to be less detectible by the static sheen test. Similarly, the potential toxicity of the discharge is not apparent in the current SPP toxicity test.

EPA has therefore sought to identify methods to control the discharge of cuttings associated with SBFs (SBF-cuttings) in a way that reflects the appropriate level of technology. One way to do this is through stock limitations on the base fluids from which the drilling fluids are formulated. This would ensure that substitution of synthetic and other oleaginous base fluids for traditional mineral oil and diesel oil reflects the appropriate level of technology. In other words, EPA wants to ensure that only the SBFs formulated from the ''best'' base fluids are allowed for discharge. Parameters that distinguish the various base fluid are the polynuclear aromatic hydrocarbon (PAH) content, sediment toxicity, rate of biodegradation, and potential for bioaccumulation.

EPA also thinks that the SBF-cuttings should be controlled with discharge limitations, such as a limitation on the toxicity of the SBF at the point of discharge, and a limitation on the mass (as volume) or concentration of SBFs discharged. The latter type of limitation would take advantage of the solids separation efficiencies achievable with SBFs, and consequently minimize the

discharge of organic and toxic components. EPA believes that SBFs separated from drill cuttings should meet zero discharge requirements, as this is the current industry practice due to the value of these drilling fluids.

Thus, EPA is proposing limits appropriate to SBF-cuttings. EPA is proposing zero discharge of neat SBFs (not associated with cuttings), which reflects current practice. The new limitations applicable to cuttings contaminated with SBFs would be as follows:

Stock Limitations on Base Fluids: (BAT/NSPS).

- Maximum PAH content 10 ppm (wt. based on phenanthrene/wt. base fluid).
- Minimum rate of biodegradation (biodegradation equal to or faster than C_{16}–C_{18} internal olefin by solid phase test).
- Maximum sediment toxicity (as toxic or less toxic than C_{16}–C_{18} internal olefin by 10-day sediment toxicity test).

Discharge Limitations on Cuttings Contaminated with SBFs:

- No free oil by the static sheen test. (BPT/BCT/NSPS).
- Maximum formation oil contamination (95 percent of representative formation oils failing 1 percent by volume in drilling fluid). (BAT/NSPS).
- Maximum well-average retention of SBF on cuttings (percent base fluid on wet cuttings). (BAT/NSPS).

Discharges remain subject to the following requirements already applicable to all drilling waste discharges and thus these requirements are not within the scope of this rulemaking:

- Mercury limitation in stock barite of 1 mg/kg. (BAT/NSPS).
- Cadmium limitation in stock barite of 3 mg/kg. (BAT/NSPS).
- Diesel oil discharge prohibition. (BAT/NSPS).

EPA may require these additional or alternative controls as part of the discharge option based on method development and data gathering subsequent to today's notice:

- Maximum sediment toxicity of drilling fluid at point of discharge (minimum LC_{50}, mL drilling fluid/kg dry sediment by 10-day sediment toxicity test or amended test). (BAT/NSPS).
- Maximum aqueous phase toxicity of drilling fluid at point of discharge (minimum LC_{50} by SPP test or amended SPP test). (BAT/NSPS).
- Maximum potential for bioaccumulation of stock base fluid (maximum concentration in sediment-eating organisms). (BAT/NSPS).

EPA is also considering a zero discharge option in the event that EPA has an insufficient basis upon which to develop appropriate discharge controls for SBF-cuttings:

- Zero discharge of drill cuttings contaminated with SBFs and other non-aqueous drilling fluids. (BPT/BCT/BAT/NSPS).

While EPA is proposing limitations on these parameters today, many of the test methods that would be used to demonstrate attainment with the limitations are still under development at this time, or additional data needs to be gathered towards validating methods, proving the variability and appropriateness of the methods, and assessing appropriate limitations for the parameters. For example, as noted in the list above, EPA is considering limitations in addition, or as an alternative, to the limitations in today's proposal. The reason for this is that EPA has insufficient data at this time to determine how to best control toxicity and whether a bioaccumulation limitation is necessary to adequately control the SBF-cuttings wastestream.

EPA would prefer to control sediment toxicity at the point of discharge. While there is an EPA approved sediment toxicity test to do this, EPA has concerns about the uniformity of the sediment used in the toxicity test, the discriminatory power and variability of the test so applied. Since the test is 10 days long, it poses a practical problem for operators who would prefer to know immediately whether cuttings may be discharges. Applying EPA's existing sediment toxicity test to the base fluid as a stock limitation ameliorates these concerns, such that, at this stage of the development of the test, EPA thinks that it is more likely to be practically applied. As this would be the preferred method of control, EPA intends to continue research into the test as applied to the drilling fluid at the point of discharge. Industry also has been conducting research to develop a sediment toxicity test that may be applied to SBFs at the point of discharge with the cuttings. Further, EPA intends to perform research into the aquatic toxicity test to see if it can be used to adequately control the discharge through modification. EPA may then consider applying an aqueous phase toxicity test, either alone or in conjunction with a sediment toxicity test of either the stock base fluid or drilling fluid at the point of discharge.

In terms of the retention of SBF on cuttings, while EPA has enough information to propose a limitation, EPA is still evaluating methods to determine attainment of this limit. For the parameter of biodegradation, EPA is proposing a numerical limit, but the analytic method for measuring attainment of the limit has not yet been validated. EPA wishes to do additional studies to validate the method and provide public notice of any subsequently developed numerical limit.

Because EPA plans to gather significant additional information in support of the final rule, EPA intends to publish a supplemental notice for public comment providing the proposed limitations and specific test methods. These data gathering activities are summarized in Section V of today's notice. Section VI details the information gathered to support this selection of parameters, and the further information that EPA intends to gather to support the methods and limitations for the intended notice and subsequent final rule.

Therefore, the purpose of today's proposal is to request comment on the candidate requirements listed above, identify the additional work that EPA intends to perform towards promulgation of the limitations, and request comments and additional data towards the selection of parameters, methods and limitations development. EPA also intends that this proposal serve as guidance to permit writers such that the proposed methods can be incorporated into permits through best professional judgement (BPJ). Such permits can be used to gather supporting information towards selection of parameters, methods development, and appropriate limitations.

The current regulations establish the geographic areas where drilling wastes may be discharged: the offshore subcategory waters beyond 3 miles from the shoreline, and in Alaska offshore waters with no 3-mile restriction. The only coastal subcategory waters where drilling wastes may be discharged is in Cook Inlet, Alaska. EPA is retaining the zero discharge limitations in areas where discharge is currently prohibited and these requirements are not within the scope of this rulemaking.

EPA is limiting the scope of today's proposed rulemaking to locations where drilling wastes may be discharged because these are the only locations for which EPA has evaluated the non-water quality environmental impacts of zero discharge versus the environmental impacts of discharging drill cuttings associated with SBFs. For example, EPA has only assessed the non-water quality environmental impacts of zero discharge beyond three miles from shore. EPA expects these impacts to be less where

the wastes are generated closer to shore. In addition, EPA has not assessed the environmental effects of these discharges in coastal areas. The current zero discharge areas are more likely to be environmentally sensitive due to the presence of spawning grounds, wetlands, lower energy (currents), and more likely to be closer to recreational swimming and fishing areas. Further, dischargers are in compliance with the zero discharge requirement and have only expressed an interest in the use of these newer fluids where drilling wastes may be discharged today.

III. Background

A. Clean Water Act

1. Summary of Effluent Limitations Guidelines and Standards

Congress adopted the Clean Water Act (CWA) to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters'' (Section 101(a), 33 U.S.C. 1251(a)). To achieve this goal, the CWA prohibits the discharge of pollutants into navigable waters except in compliance with the statute. The Clean Water Act confronts the problem of water pollution on a number of different fronts. Its primary reliance, however, is on establishing restrictions on the types and amounts of pollutants discharged from various industrial, commercial, and public sources of wastewater.

Direct dischargers must comply with effluent limitation guidelines and new source performance standards in National Pollutant Discharge Elimination System (''NPDES'') permits; indirect dischargers must comply with pretreatment standards. EPA issues these guidelines and standards for categories of industrial dischargers based on the degree of control that can be achieved using various levels of pollution control technology. The guidelines and standards are summarized below:

a. *Best Practicable Control Technology Currently Available (BPT)—sec. 304(b)(1) of the CWA.*—Effluent limitations guidelines based on BPT apply to discharges of conventional, toxic, and non-conventional pollutants from existing sources. BPT guidelines are generally based on the average of the best existing performance by plants in a category or subcategory. In establishing BPT, EPA considers the cost of achieving effluent reductions in relation to the effluent reduction benefits, the age of equipment and facilities, the processes employed, process changes required, engineering aspects of the control technologies, non-water quality environmental impacts (including energy requirements), and other factors the EPA Administrator deems appropriate. CWA § 304(b)(1)(B). Where existing performance is uniformly inadequate, BPT may be transferred from a different subcategory or category.

b. *Best Conventional Pollutant Control Technology (BCT)—sec. 304(b)(4) of the CWA.*—The 1977 amendments to the CWA established BCT as an additional level of control for discharges of conventional pollutants from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that BCT limitations be established in light of a two part ''cost-reasonableness'' test. EPA published a methodology for the development of BCT limitations which became effective August 22, 1986 (51 FR 24974, July 9, 1986).

Section 304(a)(4) designates the following as conventional pollutants: biochemical oxygen demanding pollutants (measured as BOD_5), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501).

c. *Best Available Technology Economically Achievable (BAT)—sec. 304(b)(2) of the CWA.*—In general, BAT effluent limitations guidelines represent the best available economically achievable performance of plants in the industrial subcategory or category. The CWA establishes BAT as a principal national means of controlling the direct discharge of toxic and nonconventional pollutants. The factors considered in assessing BAT include the age of equipment and facilities involved, the process employed, potential process changes, non-water quality environmental impacts, including energy requirements, and such factors as the Administrator deems appropriate. The Agency retains considerable discretion in assigning the weight to be accorded these factors. An additional statutory factor considered in setting BAT is economic achievability across the subcategory. Generally, the achievability is determined on the basis of total costs to the industrial subcategory and their effect on the overall industry (or subcategory) financial health. As with BPT, where existing performance is uniformly inadequate, BAT may be transferred from a different subcategory or category. BAT may be based upon process changes or internal controls, such as product substitution, even when these technologies are not common industry practice. The CWA does not require a cost-benefit comparison in establishing BAT.

d. *New Source Performance Standards (NSPS)—section 306 of the CWA.*—NSPS are based on the best available demonstrated control technology (BADCT) and apply to all pollutants (conventional, nonconventional, and toxic). NSPS are at least as stringent as BAT. New plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. Under NSPS, EPA is to consider the best demonstrated process changes, in-plant controls, and end-of-process control and treatment technologies that reduce pollution to the maximum extent feasible. In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

e. *Pretreatment Standards for Existing Sources (PSES)—sec. 307(b) of the CWA—and Pretreatment Standards for New Sources (PSNS)—sec. 307(b) of the CWA.*—Pretreatment standards are designed to prevent the discharge of pollutants to a publicly-owned treatment works (POTW) which pass through, interfere, or are otherwise incompatible with the operation of the POTW. Since none of the facilities to which this rule applies discharge to a POTW, pretreatment standards are not being considered as part of this rulemaking.

f. *Best Management Practices (BMPs).*—Section 304(e) of the CWA gives the Administrator the authority to publish regulations, in addition to the effluent limitations guidelines and standards listed above, to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage which the Administrator determines may contribute significant amounts of toxic and hazardous pollutants to navigable waters. Section 402(a)(1) also authorizes best management practices (BMPs) as necessary to carry out the purposes and intent of the CWA. See 40 CFR Part 122.44(k).

g. *CWA Section 304(m) Requirements.*—Section 304(m) of the CWA, added by the Water Quality Act of 1987, requires EPA to establish schedules for (i) reviewing and revising existing effluent limitations guidelines and standards and (ii) promulgating new effluent guidelines. On January 2, 1990, EPA published an Effluent Guidelines Plan (55 FR 80), in which schedules were established for developing new and revised effluent guidelines for several industry

categories, including the oil and gas extraction industry. Natural Resources Defense Council, Inc., challenged the Effluent Guidelines Plan in a suit filed in the U.S. District Court for the District of Columbia, (NRDC *et al* v. Browner, Civ. No. 89–2980). On January 31, 1992, the Court entered a consent decree (the ''304(m) Decree''), which establishes schedules for, among other things, EPA's proposal and promulgation of effluent guidelines for a number of point source categories. The most recent Effluent Guidelines Plan was published in the **Federal Register** on September 4, 1998 (63 FR 47285). This plan requires, among other things, that EPA propose the Synthetic-Based Drilling Fluids Guidelines by 1998 and promulgate the Guidelines by 2000.

2. Prior Federal Rulemakings and Other Notices

On March 4, 1993, EPA issued final effluent guidelines for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category (58 FR 12454). The data and information gathering phase for this rulemaking thus corresponded to the introduction of SBFs in the Gulf of Mexico. Because of this timing, the range of drilling fluids for which data and information were available to EPA was limited to water-based drilling fluids (WBFs) and oil-based drilling fluids (OBFs) using diesel and mineral oil. Industry representatives, however, submitted information on SBFs during the comment period concerning environmental benefits of SBFs over OBFs and WBFs, and problems with false positives of free oil in the static sheen test applied to SBFs.

The requirements in the offshore rule applicable to drilling fluids and drill cuttings consist of mercury and cadmium limitations on the stock barite, a diesel oil discharge prohibition, a toxicity limitation on the suspended particulate phase (SPP) generated when the drilling fluids or drill cuttings are mixed in seawater, and no discharge of free oil as determined by the static sheen test.

While the SPP toxicity test and the static sheen test, and their limitations, were developed for use with WBF, the offshore regulation does not specify the types of drilling fluids and drill cuttings to which these limitations apply. Thus, under the rule, any drilling waste in compliance with the discharge limitations could be discharged. When the offshore rule was proposed, EPA believed that all drilling fluids, be they WBFs, OBFs, or SBFs, could be controlled by the SPP toxicity and static sheen tests. This is because OBFs based on diesel oil or mineral oil failed one or both of the SPP toxicity test and no free oil static sheen test. In addition, OBFs based on diesel oil were subject to the diesel oil discharge prohibition.

EPA thought SBFs could also be adequately controlled by the regulation based on comments received from industry. After the offshore rule was proposed, EPA received several industry comments which focused on the fact that the static sheen test could often be interpreted as giving a false positive for the presence of diesel oil, mineral oil, or formation hydrocarbons. For this reason, the industry commenters contended that SBFs should be exempt from compliance with the no free oil limitation required by the proposed offshore effluent guidelines.

In the final rulemaking in 1993, EPA's response to these comments was that the prohibition on discharges of free oil was an appropriate limitation for discharge of drill fluids and drill cuttings, including SBFs. While EPA agreed that some of the newer SBFs may be less toxic and more readily biodegradable than many of the OBFs, EPA was concerned that no alternative method was offered for determining compliance with the no free oil standard to replace the static sheen test. In other words, if EPA were to exclude certain fluids from the requirement, there would be no way to determine if at that particular facility, diesel oil, mineral oil or formation hydrocarbons were also being discharged.

Also in the final offshore rule, EPA encouraged the use of drilling fluids that were less toxic and biodegraded faster. EPA solicited data on alternative ways of monitoring for the no free oil discharge requirement, such as gas chromatography or other analytical methods. EPA also solicited information on technology issues related to the use of SBFs, any toxicity data or biodegradation data on these newer fluids, and cost information.

By focusing on the issue of false positives with the static sheen test, EPA interpreted the offshore effluent guidelines to mean that SBFs could be discharged provided they complied with the current discharge requirements. EPA did not think, however, that many, if any, SBFs would be able to meet the no free oil requirement.

In the final coastal effluent guidelines, EPA raised the issue of false negatives with the static sheen test as opposed to the issue of false positives raised during the offshore rulemaking. EPA had information indicating that the static sheen test does not adequately detect the presence of diesel, mineral, or formation oil in SBFs. In addition, EPA raised other concerns regarding the inadequacy of the current effluent guidelines to control of SBF wastestreams. Thus the final coastal effluent guidelines, published on December 16, 1996 (61 FR 66086), constitute the first time EPA identified, as part of a rulemaking, the inadequacies of the current regulations and the need for new BPT, BAT, BCT, and NSPS controls for discharges associated with SBFs.

The coastal rule adopted the offshore discharge requirements to allow discharge of drilling wastes in one geographic area of the coastal subcategory; Cook Inlet, Alaska, and prohibited the discharge of drilling wastes in all other coastal areas.

Due to the lack of information concerning appropriate controls, EPA could not provide controls specific to SBFs as a part of the coastal rule. However, the coastal rulemaking solicited comments on SBFs. In responding to these comments, EPA again identified certain environmental benefits of using SBFs, and stated that allowing the controlled discharge of SBF-cuttings would encourage their use in place of OBFs. EPA also raised the inadequacies of the current effluent guidelines to control the SBF wastestreams, and provided an outline of the parameters which EPA saw as important for adequate control. The inadequacies cited include the inability of the static sheen test to detect formation oil or other oil contamination in SBFs and the inability of the SPP toxicity test to adequately measure the toxicity of SBFs. EPA offered alternative tests of gas chromatography (GC) and a benthic toxicity test to verify the results of the static sheen and the suspended particulate phase (SPP) toxicity testing currently required. EPA also mentioned the potential need for controls on the base fluid used to formulate the SBF, based on one or more of the following parameters: PAH content, toxicity (preferably sediment toxicity), rate of biodegradation, and bioaccumulation potential.

The final coastal rule also incorporated clarifying definitions of drilling fluids for both the offshore and coastal subcategories to better differentiate between the types of drilling fluids. The rule provided guidance to permit writers needing to write limits for SBFs on a best professional judgement (BPJ) basis as using GC as a confirmation tool to assure the absence of free oil in addition to meeting the current no free oil (static sheen), toxicity, and barite limits on mercury and cadmium. EPA

recommended Method 1663 as described in EPA 821–R–92–008 as a gas chromatograph with flame ionization detection (GC/FID) method to identify an increase in n-alkanes due to crude oil contamination of the synthetic materials coating the drill cuttings. Additional tests, such as benthic toxicity conducted on the synthetic material prior to use or whole SBF prior to discharge, were also suggested for controlling the discharge of cuttings contaminated with drilling fluid.

EPA stated intentions to evaluate further the test methods for benthic toxicity and determine an appropriate limitation if this additional test is warranted. In addition, test methods and results for bioaccumulation and biodegradation, as indications of the rate of recovery of the cuttings piles on the sea floor, were to be evaluated. EPA recognized that evaluations of such new testing protocols may be beyond the technical expertise of individual permit writers, and so stated that these efforts would be coordinated as a continuing effluent guidelines effort. Today's proposal is a result of these efforts.

B. Permits

Four EPA Regions currently issue or review permits for offshore and coastal oil and gas well drilling activities in areas where drilling wastes may be discharged: Region 4 in the Eastern Gulf of Mexico (GOM), Region 6 in the Central and Western GOM, Region 9 in offshore California, and Region 10 in offshore and Cook Inlet, Alaska. Permits in Regions 4, 9 and 10 never allowed the discharge of SBFs, and those three Regions are currently preparing final general permits that either specifically disallow SBF discharges until adequate discharge controls are available to control the SBF wastestreams, or allow a limited use of SBF to facilitate information gathering.

Discharge of drill cuttings contaminated with SBF (SBF-cuttings) has occurred under the Region 6 offshore continental shelf (OCS) general permit issued in 1993 (58 FR 63964), and the general permit reissued on November 2, 1998 (63 FR 58722) again does not specifically disallow the continued discharge of SBF-cuttings. The reason for these differences between Region 6 and the other EPA Regions relates to the timing of the 1993 Region 6 general permit and the issues raised in comments during the issuance of that permit.

The previous individual and general permits of Regions 4, 9 and 10 were issued long before SBFs were developed and used. In Region 6, however, the first SBF well was drilled in June of 1992 and the development of the Region 6 OCS general permit, published December 3, 1993 (58 FR 63964), thus corresponded to the introduction of SBF use in the GOM. After proposal of this permit, industry representatives commented that the no free oil limitation as measured by the static sheen test should be waived for SBFs, due to the occurrence of false positives. They contended that a sheen was sometimes perceived when the SBF was known to be free of diesel oil, mineral oil or formation oil. These comments were basically the same as those submitted as part of the offshore rulemaking, which occurred in the same time frame. EPA responded as it had in the offshore rulemaking, maintaining the static sheen test until there existed a replacement test to determine the presence of free oil. EPA stated that if the current discharge requirements could be met then the drilling fluid and associated wastes could be discharged. This response indicated EPA's position that SBF drilling wastes could be discharged as long as the discharge met permit requirements. But again, in the context of these comments, EPA did not expect that many, if any SBFs, would be able to meet the static sheen requirements.

In addition to the requirements of the offshore guidelines, the Region 6 OCS general permit also prohibited the discharge of oil-based and inverse emulsion drilling fluids. Although SBFs are, in chemistry terms, inverse emulsion drilling fluids, the definition in the permit limited the term ''inverse emulsion drilling fluids'' to mean ''an oil-based drilling fluid which also contains a large amount of water.'' Further, the permit provides a definition for oil-based drilling fluid as having ''diesel oil, mineral oil, or some other oil as its continuous phase with water as the dispersed phase.'' Since the SBFs clearly do not have diesel or mineral oil as the continuous phase, there was a question of whether synthetic base fluids (and more broadly, other oleaginous base fluids) used to formulate the SBFs are ''some other oil.'' With consideration of the intent of the inverse emulsion discharge prohibition, and the known differences in polynuclear aromatic hydrocarbon content, toxicity, and biodegradation between diesel and mineral oil versus the synthetics, EPA determined that SBFs were not inverse emulsion drilling fluids as defined in the Region 6 general permit. This determination is exemplified by the separate definitions for OBFs and SBFs introduced with the Coastal Effluent Guidelines (see 61 FR 66086, December 16, 1996).

In late 1998 and early 1999, all four Regions are (re)issuing their general permits for offshore (Regions 4, 6 and 9) and coastal (Region 10) oil and gas wells. Once the effluent guidelines or guidance becomes available, EPA intends to reopen the permits to add requirements that adequately control SBF drilling wastes.

EPA intends for today's proposal to act as guidance such that the Regions do not have to wait until issuance of a final rule planned for December 2000, but may propose to add the appropriate discharge controls through best professional judgement (BPJ). In this manner, the controlled discharge of SBF may be used to further aid EPA in gathering information subsequent to today's proposal.

C. Pollution Prevention Act

The Pollution Prevention Act of 1990 (PPA) (42 U.S.C. 13101 et seq., Pub. L. 101–508, November 5, 1990) ''declares it to be the national policy of the United States that pollution should be prevented or reduced whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and disposal or release into the environment should be employed only as a last resort * * *'' (Sec. 6602; 42 U.S.C. 13101 (b)). In short, preventing pollution before it is created is preferable to trying to manage, treat or dispose of it after it is created. The PPA directs the Agency to, among other things, ''review regulations of the Agency prior and subsequent to their proposal to determine their effect on source reduction'' (Sec. 6604; 42 U.S.C. 13103(b)(2)). EPA reviewed this effluent guideline for its incorporation of pollution prevention.

According to the PPA, source reduction reduces the generation and release of hazardous substances, pollutants, wastes, contaminants, or residuals at the source, usually within a process. The term source reduction ''include[s] equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training or inventory control. The term 'source reduction.' does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a hazardous substance, pollutant, or contaminant through a

process or activity which itself is not integral to or necessary for the production of a product or the providing of a service.'' 42 U.S.C. 13102(5). In effect, source reduction means reducing the amount of a pollutant that enters a waste stream or that is otherwise released into the environment prior to out-of-process recycling, treatment, or disposal.

In this proposed rule, EPA supports pollution prevention technology by encouraging the use of SBFs based on certain synthetic materials and other similarly performing materials in place of traditional oil-based drilling fluids based on diesel oil and mineral oil. The waste generated from SBFs is anticipated to have lower toxicity, lower bioaccumulation potential, faster biodegradation, and elimination of polynuclear aromatic hydrocarbons, including those which are priority pollutants. With these improved characteristics, and to encourage their use in place of OBFs, EPA is proposing to allow the controlled on-site discharge of the cuttings associated with SBF. Use of SBF in place of OBF will eliminate the need to barge to shore or inject oily waste cuttings, reducing fuel use, air emissions, and land disposal. It also eliminates the risk of OBF and OBF-cuttings spills. In addition, the proposed regulatory option includes efficient closed-loop recycling systems to reduce the quantity of SBF discharged with the drill cuttings. A discussion of this pollution prevention technology is contained in Section VI of this notice and in the Development Document.

IV. Description of Process and Well Drilling Activities

A. Well Drilling Process Description

Drilling occurs in two phases: exploration and development. Exploration activities are those operations involving the drilling of wells to locate hydrocarbon bearing formations and to determine the size and production potential of hydrocarbon reserves. Development activities involve the drilling of production wells once a hydrocarbon reserve has been discovered and delineated.

Drilling for oil and gas is generally performed by rotary drilling methods which use a circularly rotating drill bit that grinds through the earth's crust as it descends. Drilling fluids are pumped down through the drill bit via a pipe that is connected to the bit, and serve to cool and lubricate the bit during drilling. The rock chips that are generated as the bit drills through the earth are termed drill cuttings. The drilling fluid also serves to transport the drill cuttings back up to the surface through the space between the drill pipe and the well wall (this space is termed the annulus), in addition to controlling downhole pressure and stabilizing the well bore.

As drilling progresses, large pipes called ''casing'' are inserted into the well to line the well wall. Drilling continues until the hydrocarbon bearing formations are encountered. In areas where drilling fluids and drill cuttings are allowed to be discharged under the current regulations, well depths range from approximately 4,000 to 12,000 feet deep, and it takes approximately 20 to 60 days to complete drilling.

On the surface, the drilling fluid and drill cuttings undergo an extensive separation process to remove as much fluid from the cuttings as possible. The fluid is then recycled into the system, and the cuttings become a waste product. The drill cuttings retain a certain amount of the drilling fluid that are discharged or disposed with the cuttings. Drill cuttings are discharged by the shale shakers and other solids separation equipment. Drill cuttings are also cleaned out of the mud pits and from the solid separation equipment during displacement of the drilling fluid system. Intermittently during drilling, and at the end of the drilling process, drilling fluids may become wastes if they can no longer be reused or recycled.

In the relatively new area of deepwater drilling, generally greater than 3000′ water depth, new drilling methods are evolving which can significantly improve drilling efficiencies and thereby reduce the volume of drilling fluid discharges as well as reduce non-water quality effects of fuel and steel consumption and air emissions. Subsea drilling fluid boosting, referred to as ''subsea pumping'', is one such technology. Rotary drilling methods are generally performed as described with the exception that the drilling fluid is energized or boosted by use of a pump at or near the seafloor. By boosting the drilling fluid, the adverse effect on the wellbore caused by the drilling fluid pressure from the seafloor to the surface is eliminated, thereby allowing wells to be drilled with as much as a 50% reduction in the number of casing strings generally required to line the well wall. Wells are drilled in less time, including less trouble time. To enable the pumping of drilling fluids and cuttings to the surface, some drill cuttings, larger than approximately one-fourth of an inch, are separated from the drilling fluid at the seafloor since these cuttings cannot reliably be pumped to the surface. The drill cuttings which are separated at the seafloor are discharged through an eductor hose at the seafloor within a 300′ radius of the well site. For purposes of monitoring, representative samples of drill cuttings discharged at the seafloor can be transported to the surface and separated from the drilling fluid in a manner similar to that employed at the seafloor. The drilling fluid, which is boosted at the seafloor and transports most of the drill cuttings back to the surface, is processed as described in the general rotary drilling methods described above in this section.

Once the target formations have been reached, and a determination made as to which have commercial potential, the well is made ready for production by a process termed ''completion.'' Completion involves cleaning the well to remove drilling fluids and debris, perforating the casing that lines the producing formation, inserting production tubing to transport the hydrocarbon fluids to the surface, and installing the surface wellhead. The well is then ready for production, or actual extraction of hydrocarbons.

B. Location and Activity

This proposed regulation would establish discharge limitations for SBFs in areas where drilling fluids and drill cuttings are allowed for discharge. These discharge areas are the offshore waters beyond 3 miles from shore except the offshore waters of Alaska which has no 3 mile discharge restriction, and the coastal waters of Cook Inlet, Alaska. Drilling is currently active in three regions in these discharge areas: (i) the offshore waters beyond three miles from shore in the Gulf of Mexico (GOM), (ii) offshore waters beyond three miles from shore in California, and (iii) the coastal waters of Cook Inlet, Alaska. Offshore Alaska is the only other area where drilling is active and effluent guidelines allows discharge. However, drilling wastes are not currently discharged in the Alaska offshore waters.

Among these three areas, most drilling activity occurs in the GOM, where 1,302 wells were drilled in 1997, compared to 28 wells drilled in California and 7 wells drilled in Cook Inlet. In the GOM, over the last few years, there has been high growth in the number of wells drilled in the deepwater, defined as water greater than 1,000 feet deep. For example, in 1995, 84 wells were drilled in the deepwater, comprising 8.6 percent of all GOM wells drilled that year. By 1997, that number increased to 173 wells drilled and comprised over 13 percent of all GOM

wells drilled. The increased activity in the deepwater increases the usefulness of SBFs. Operators drilling in the deepwater cite the potential for riser disconnect in floating drill ships, which favors SBF over OBF; higher daily drilling cost which more easily justifies use of more expensive SBFs over WBFs; and greater distance to barge drilling wastes that may not be discharged (i.e., OBFs).

C. Drilling Wastestreams

Drilling fluids and drill cuttings are the most significant wastestreams from exploratory and development well drilling operations. This rule proposes limitations for the drilling fluid and cuttings wastestream resulting when SBFs or other non-aqueous drilling fluids are used. All other wastestreams and drilling fluids have current applicable limitations which are outside the scope of this rulemaking. A summary of the characteristics of these wastes is presented in Section VI of this notice. A more detailed discussion of the origins and characteristics of these wastes is included in the Development Document.

V. Summary of Data Gathering Efforts

A. Expedited Guidelines Approach

This regulation is being developed using an expedited rulemaking process. This process relies on stakeholder support to develop the initial technology and regulatory options. At various stages of information gathering, industry, EPA and other stakeholders present and discuss their preferred options and identify differences in opinion. This proposal, as part of the expedited process, is being presented today in a shorter developmental time period, and with less information than a typical effluent guidelines proposal. The proposed rule is then a tool to identify the candidate requirements, and request comments and additional data. EPA plans to continue this expedited rulemaking process of relying on industry, environmental groups, and other stakeholder support for the further regulatory development after proposal.

EPA encourages full public participation in developing the final SBF Guidelines. This expedited rulemaking process succeeds with more open communication between EPA, the regulated community, and other stakeholders, and relies less on formal data and information gathering mechanisms. The expedited guidelines approach is suitable when EPA, industry, and other stakeholders have a common goal on the structure of the limitations and standards. EPA believes this is the case with the SBF rulemaking; EPA is proposing to allow the controlled discharge of the SBF-cuttings wastestream to encourage the use and further development of this pollution prevention technology. Based on information to date, EPA believes that this option has better environmental results than the current use and subsequent land disposal or injection of OBFs. Through the exchange of information among the stakeholders, EPA understands the industry's interest in discharging the SBF-cuttings wastestream because discharge of SBFs is more likely to be cost effective as a replacement to the diesel and mineral oil based OBFs. EPA was able to accommodate both environmental benefits and business interests in today's proposal.

Throughout regulatory development, EPA has worked with representatives from the oil and gas industry and several trade associations, including the National Ocean Industries Association (NOIA) and the American Petroleum Institute (API), SBF vendors, solids control equipment vendors, the U.S. Department of Energy, the U.S. Department of Interior Minerals Management Service, the Texas Railroad Commission, and research and regulatory bodies of the United Kingdom and Norway, to develop effluent limitations guidelines and standards that represent the appropriate level of technology (e.g., BAT). The Agency also discussed the progress of the rulemaking with the Natural Resources Defense Council (NRDC) and invited its participation. The Cook Inlet Keepers are participating in the rulemaking as well.

As part of the expedited approach to this rulemaking, EPA has chosen not to gather data using the time consuming approach of a Clean Water Act section 308 questionnaire, but rather by using data submitted by industry, vendors, academia, and others, along with data EPA can develop in a limited period of time. Because all of the facilities affected by this proposal are direct dischargers, the Agency did not conduct an outreach survey to POTWs.

Subsequent to today's proposal, EPA intends to continue its data gathering efforts for support of the final rule. These continuing efforts are discussed below in conjunction with the information already gathered. Because of these continuing information gathering activities, EPA expects that it will publish a subsequent notice of any data either generated by EPA or submitted after this proposal that will be used to develop the final rule.

B. Identification of Information Needs

As part of the final coastal effluent guidelines, published on December 16, 1996 (61 FR 66086), EPA stated that appropriate and adequate discharge controls would be necessary to allow the discharge of SBF-cuttings under BPT, BAT, BCT, and NSPS in NPDES permits. As detailed in Section III of today's notice, in the final coastal effluent guidelines EPA recommended gas chromatography (GC) as a test for formation oil contamination, and a sediment toxicity test as a replacement for the suspended particulate phase (SPP) toxicity testing currently required. EPA also mentioned the potential need for controls on the base fluid used to formulate the SBF, controlling one or more of the following parameters: PAH content, toxicity (preferably sediment toxicity), rate of biodegradation, and bioaccumulation potential. EPA summarized the information available from seabed surveys at SBF-cuttings discharge sites.

Subsequent to the publication of the final coastal effluent guidelines, EPA continued research into the appropriate controls for the SBF-cuttings wastestream, and presented its findings to stakeholders at meetings held in Dallas, Texas, on February 19, 1998, and in Houston on May 8 and 9, 1997. EPA also presented data and information requirements to develop adequate and appropriate controls for the SBF-cuttings wastestream at four conferences, in Aberdeen, Scotland, on June 23 and 24, 1997, in Houston, Texas on February 9, 1998, again in Aberdeen Scotland on June 18 and 19, 1998, and at the Minerals Management Service Information Transfer Meeting held in New Orleans, Louisiana on December 18, 1997. The conferences in Scotland were germane because of the work that the Scottish Office Agriculture, Environment and Fisheries Department had performed on sediment toxicity testing, biodegradability testing, and seabed surveys at SBF-cuttings and OBF-cuttings discharge sites. This detailed level of work has not been performed in the United States.

EPA conducted literature reviews and in September 1997 published documents entitled ''Bioaccumulation of Synthetic-Based Drilling Fluids,'' ''Biodegradation of Synthetic-Based Drilling Fluids,'' ''Assessment and Comparison of Available Drilling Waste Data from Wells Drilled Using Water Based Fluids and Synthetic Based Fluids,'' and ''Seabed Survey Review and Summary.'' The purpose of these documents was to help direct EPA's and other stakeholder's research efforts in

defining BPT, BAT, BCT, and NSPS, and address CWA 403(c) requirements for SBFs.

Industry stakeholders, with the motivation of having SBFs addressed in NPDES permits that allow the discharge of SBF-cuttings, assisted EPA in the development of methods and data gathering to describe currently available technologies. Thus, by means of meetings, conferences, and other stakeholder meetings, EPA detailed the methods and/or types of information required in order to support BPT, BCT, BAT, and NSPS controls in NPDES permits. The past and anticipated future efforts by various stakeholder groups and the EPA are presented below.

C. Stakeholder Technical Work Groups

In order to concentrate efforts on certain technical issues, in May of 1997 industry prepared studies on the following subjects: (a) the determination of formation oil contamination in SBFs, (b) toxicity testing of SBFs and base fluids, (c) quantity of SBF discharged (retention of base fluid on cuttings), and (d) seabed surveys at SBF-cuttings discharge sites. Industry representatives formed work groups to address these issues. The sections below describe their work.

1. Formation Oil Contamination Determination (Analytical)

The goal of this work group was to define the monitoring and compliance method to determine crude oil (or other oil) contamination of SBF-cuttings. The work group has issued several reports concerning the static sheen test, and developed two replacement tests for formation oil contamination, one based on fluorescence and the other on gas chromatography with mass spectroscopy detection (GC/MS).

On September 28, 1998, the workgroup published the final draft of the Phase I report entitled ''Evaluation of Static Sheen Test for Water-based Muds, Synthetic-based Muds and Enhanced Mineral Oils. The conclusions of the report are that the static sheen test is not a good indicator of oil contamination in SBFs, and that in WBFs formation oil contamination is often detected at 1.0 percent and sometimes as low as 0.5 percent.

On October 21, 1998, the work group published its final draft to the Phase II report entitled ''Survey of Monitoring Approaches for the Detection of Oil Contamination in Synthetic-based Drilling Muds.'' This document lists thirteen methods that the work group considered as a replacement to the static sheen test. From these thirteen, EPA selected the reverse phase extraction method to be used on offshore drilling sites, and the GC/MS method for onshore baseline measurements.

On November 16, 1998, the work group published its final draft of the Phase III report entitled ''Laboratory Evaluation of Static Sheen Replacements: RPE Method and GC/MS Method.'' This report provides the methods. The future work of the Analytical Work Group is to validate these methods.

2. Retention on Cuttings

The goals of this work group were to determine the SBF retention on cuttings using the equipment currently used in the Gulf of Mexico (GOM), and investigate ways of determining the total quantity of SBF discharged when drilling a well. To address the first goal, API reported data from GOM wells on the amount of SBF base fluid retained on drill cuttings. The results were published on August 29, 1997, in a report entitled ''Retention of Synthetic-Based Drilling Material on Cuttings Discharged to the Gulf of Mexico.''

To address the second goal of determining the total quantity of SBF discharged, the work group has created a spreadsheet which records information allowing two independent analyses of the SBF quantity discharged. One method is based on a mass balance of the SBF, and the other is based on retort measurements of the cuttings wastestream. Both methods of analyses carry certain benefits and drawbacks. By comparing the results from the two analyses, EPA intends to select one method as preferred for the final rule. The work group is currently gathering these comparative data. The preferred method will then be validated for inclusion in the final rule. At this time, EPA thinks that the retort measurement is preferable to implement, and therefore it is the method proposed today. As further information is gathered, however, EPA may decide that attainment of the limit in the final rule is to be determined by the mass balance method.

3. Toxicity Testing

The goal of this work group was to define the toxicity test for monitoring and compliance of SBF-cuttings. EPA has indicated that the test could be performed on either the stock base fluid, or the SBF separated from the cuttings at the point of discharge.

Through data generated by members of the work group, the work group has shown that SBF and synthetic base fluid toxicity are mainly evident in the sedimentary phase. When measured in the suspended particulate phase (SPP) in the current Mysid shrimp toxicity test, the toxicity is not evident and the results are highly variable, and are easily affected by the intensity of stirring and emulsifier content of the SBF.

Having shown that an aqueous phase test is unlikely to yield satisfactory results with SBFs and associated base fluids, the work group has been investigating sediment toxicity tests, mainly the 10-day sediment toxicity test with amphipods (ASTM E1367–92). To effect this work, API funded a currently ongoing contract to evaluate four test methods: 10-day acute sediment toxicity test with (a) *Ampelisca abdita,* (b) *Leptocheirus plumulosus,* and (c) *Mysidopsis bahia,* and (d) *microtox tests.* Main issues that the work group hopes to resolve are discriminatory power of the method and variability in results. Since the API contract work began, the work group has considered many variables to the sediment toxicity test to ameliorate these problems. The work group is investigating: organisms other than amphipods, such as Mysid shrimp and polychaetes; shortening the length of the test, *i.e.* from 10 days to 4 days; and the use of formulated sediments in place of natural sediments. Work continues to determine the most appropriate method to evaluate the toxic effect of the SBF discharged with drill cuttings.

4. Environmental Effects/Seabed Surveys

The goal of this work group was to determine the spacial and temporal recovery of the seafloor at sites where SBF-cuttings had been discharged, and compare these effects with effects caused by the discharge of WBF and WBF-cuttings discharge.

The work group performed a five-day screening cruise at three offshore oil platforms where SBFs has been used and SBF-cuttings discharged for the purpose of gathering preliminary environmental effects information. This screening cruise, and its planning, was performed in collaboration with EPA and with the use of the EPA Ocean Survey Vessel Peter W. Anderson. The study conducted a preliminary evaluation of offshore discharge locations and determine the areal extent of observable physical, chemical, and biological impact. EPA intended that this base information would provide (1) information relative to the immediate concerns on impacts, and (2) valuable preliminary information for designing future offshore assessments.

The study provided preliminary information on cuttings deposition, SBF content of nearfield marine sediments,

anoxia in nearfield sediments, qualitative information on biological communities in the area, and toxicity of field collected sediments. The results of this survey were published on October 21, 1998, in a report entitled ''Joint EPA/Industry Screening Survey to Assess the Deposition of Drill Cuttings and Associated Synthetic Based Mud on the Seabed of the Louisiana Continental Shelf, Gulf of Mexico.''

The ongoing effort of the work group is to address CWA 403(c) permit requirements for seabed surveys by organizing collaborative industry seabed surveys at selected SBF-discharge sites.

D. EPA Research on Toxicity, Biodegradation, Bioaccumulation

Subsequent to today's proposal, EPA plans to compare the relative environmental effects of SBFs and OBFs in terms of (i) sediment and aquatic toxicity, (ii) biodegradation, and (iii) bioaccumulation. The methods development to occur as part of this research, and the resulting data, are intended to be used towards the final stock base fluid limitations and SBF discharge limitations proposed today.

The base fluids to consider in the sediment toxicity, biodegradation, and bioaccumulation tests are the full range of synthetic and oleaginous base fluids. These include the synthetic oils such as vegetable esters, linear alpha olefins, internal olefins and poly alpha olefins, the traditional base oils of mineral oil and diesel oil, and the newer more refined and treated oils such as enhanced mineral oil and paraffinic oils. These oily base fluids are common in that they are immiscible (do not mix) with water, and form drilling fluids that do not disperse in water.

The outline of this research plan in terms of goals and considerations is as follows:

- For sediment toxicity, this plan intends to investigate the effects of base fluid, whole mud formulation, and crude oil contamination on sediment toxicity as measured by the 10-day acute sediment toxicity test performed in natural sediment with *Ampelisca abdita and Leptocheirus plumulosus.* The goals of this research are threefold:
- Amend the EPA 10-day acute sediment toxicity test for application to SBFs and base fluids.
- Determine the LC_{50} values for the base fluids by this method, potentially for determination of stock limitations values.
- Determine the effects of mud formulation and crude oil contamination on sediment toxicity by maintaining the base fluid constant. The purpose is to investigate the parameters which affect toxicity in SBFs.
- For aqueous phase toxicity, this plan intends to investigate if any correlation exists between aqueous phase toxicity to Mysid shrimp and sediment toxicity.
- For biodegradation, this plan intends to perform the solid phase test or modified solid phase test as developed by the Scottish Office Agriculture, Environment and Fisheries Department for a range of oily base fluids, and environments of the Gulf of Mexico, Offshore California, Cook Inlet Alaska, and Offshore Alaska.
- For bioaccumulation, this plan intends to test bioconcentration in *Macoma nasuta* and *Nereis virens.*

The research concerning sediment toxicity testing that API supports is seen as complementary to, and not overlapping with, this EPA plan. API's goal is to identify a bioassay test organism and protocol to accurately and reliably evaluate the toxicity of SBF and OBF in sediments. The API research is concentrating efforts on using both formulated and natural sediments, and possibly a test period shorter than the standard 10-day EPA method. Thus, while EPA is focusing on investigating the parameters that affect toxicity of SBFs, the API research is looking ahead to discharge monitoring requirements with the goal of identifying an appropriate and reliable test method.

E. EPA Investigation of Solids Control Technologies for Drilling Fluids

EPA has contacted numerous vendors of solids control equipment and requested information on performance and cost of the various solids separation units available. EPA has also received information from operators data showing the performance of the vibrating centrifuge technology. As part of its investigation of solids control equipment used on offshore drilling platforms, EPA visited Amoco's Marlin deepwater drilling project aboard the Amirante semi-submersible drilling platform located in Viosca Knoll Block 915 approximately 100 miles south of Mobile, Alabama. The primary purpose of this site visit was to observe the demonstration of the vibrating centrifuge drilling fluid recovery device heretofore used only on North Sea drilling projects. The device reportedly can produce drill cuttings containing less than 6 percent by volume synthetic drilling fluid on wet cuttings when well operated and maintained and used in conjunction with shale shakers that are well operated and maintained. The information gathered by the EPA during this trip is described in a report dated August 7, 1998, entitled ''Demonstration of the 'Mud 10' Drilling Fluid Recovery Device at the Amoco Marlin Deepwater Drill Site.''

F. Assistance From Other State and Federal Agencies

The United States Department of Interior Minerals Management Service (MMS) maintains data of the number of wells drilled in offshore waters under MMS jurisdiction, i.e., those that are not territorial seas. In general, this covers the offshore waters beyond 3 miles from the shoreline, which corresponds with the area were drilling wastes are currently allowed for discharge and so is the same area affected by this rule. MMS supplied data for years 1995, 1996, and 1997 of the number of wells drilled in the GOM and offshore California according to depth (less than or greater than 1000 feet water depth) and type of well (exploratory or development). Since Texas jurisdiction over oil and gas leases extends out to 10 miles, information was requested and received from the Texas Railroad Commission regarding the number of wells drilled in Texas territorial seas from 3 miles to 10 miles from shore. This is the area in the GOM that is affected by this proposed rule, but not included in the MMS data.

Information concerning the number of wells drilled in the state waters of Upper Cook Inlet, Alaska, was gathered from the Alaska Oil and Gas Commission. The Alaska Oil and Gas Commission provided information of the number of wells drilled in Upper Cook Inlet for the years 1995, 1996, and 1997, according to type of well as exploratory or development.

MMS also assisted in developing the cruise plan of the screening seabed survey mentioned in section V.C.4 above.

The United States Department of Energy (DOE) has been active in assisting EPA to gather information concerning drilling waste disposal methods and costs, and type of fuel used on offshore platforms. In November 1998 Argonne National Laboratory, under contract with DOE, published the results of this information gathering effort in a report entitled ''Data Summary of Offshore Drilling Waste Disposal Practices.''

Also under contract with DOE, Brookhaven National Laboratory developed a comparative risk assessment for the discharge of SBFs. The risk assessment, published November 1998, is entitled ''Framework for a Comparative Environmental Assessment of Drilling Fluids.''

VI. Development of Effluent Limitations Guidelines and Standards

A. Waste Generation and Characterization

Drill cuttings are produced continuously at the bottom of the hole at a rate proportionate to the advancement of the drill bit. These drill cuttings are carried to the surface by the drilling fluid, where the cuttings are separated from the drilling fluid by the solids control system. The drilling fluid is then sent back down hole, provided it still has characteristics to meet technical requirements. Various sizes of drill cuttings are separated by the solids separations equipment, and it is necessary to remove the fines (small sized cuttings) as well as the large cuttings from the drilling fluid to maintain the required flow properties.

SBFs, used or unused, are considered a valuable commodity and not a waste. It is industry practice to continuously reuse the SBF while drilling a well interval, and at the end of the well, to ship the remaining SBF back to shore for refurbishment and reuse. Compared to WBFs, SBFs are relatively easy to separate from the drill cuttings because the drill cuttings do not disperse in the drilling fluid to the same extent. With WBF, due to dispersion of the drill cuttings, drilling fluid components often need to be added to maintain the required drilling fluid properties. These additions are often in excess of what the drilling system can accommodate. The excess ''dilution volume'' of WBF is a resultant waste. This dilution volume waste does not occur with SBF. For these reasons, SBF is only discharged as a contaminant of the drill cuttings wastestream. It is not discharged as neat drilling fluid (drilling fluid not associated with cuttings).

The top of the well is normally drilled with a WBF. As the well becomes deeper, the performance requirements of the drilling fluid increase, and the operator may, at some point, decide that the drilling fluid system should be changed to either a traditional OBF based on diesel oil or mineral oil, or an SBF. The system, including the drill string and the solids separation equipment, must be changed entirely from the WBF to the SBF (or OBF) system, and the two do not function as a blended system. The entire system is either (a) a water dispersible drilling fluid such as a WBF, or (b) a water non-dispersible drilling fluid such as an SBF. The decision to change the system from a WBF water dispersible system to an OBF or SBF water non-dispersible system depends on many factors including:

- The operational considerations, i.e. rig type (risk of riser disconnects with floating drilling rigs), rig equipment, distance from support facilities,
- The relative drilling performance of one type fluid compared to another, e.g., rate of penetration, well angle, hole size/casing program options, horizontal deviation,
- The presence of geologic conditions that favor a particular fluid type or performance characteristic, e.g., formation stability/sensitivity, formation pore pressure vs. fracture gradient, potential for gas hydrate formation,
- Drilling fluid cost—base cost plus daily operating cost,
- Drilling operation cost—rig cost plus logistic and operation support,
- Drilling waste disposal cost.

Industry has commented that while the right combination of factors that favor the use of SBF can occur in any area, they most frequently occur with ''deep water'' operations. This is due to the fact that these operations are higher cost and can therefore better justify the higher initial cost of SBF use.

The volume of cuttings generated while drilling the SBF intervals of a well depends on the type of well, development or production, and the water depth. According to analyses of the model wells provided by industry representatives, wells drilled in less than 1,000 feet of water are estimated to generate 565 barrels for a development well and 1,184 barrels for an exploratory well. Wells drilled in water greater than 1,000 feet deep are estimated to generate 855 barrels for a development well, and 1,901 for an exploratory well. These values assume 7.5 percent washout, based on the rule of thumb reported by industry representatives of 5 to 10 percent washout when drilling with SBF. Washout is caving in or sluffing off of the well bore. Washout, therefore, increases hole volume and increases the amount of cuttings generated when drilling a well. Assuming no washout, the values above become, respectively, 526, 1,101, 795, and 1,768, barrels.

The drill cuttings range in size from large particles on the order of a centimeter in size to small particles a fraction of a millimeter in size, called fines. As the drilling fluid returns from downhole laden with drill cuttings, it normally is first passed through primary shale shakers which remove the largest cuttings, ranging in size of approximately 1 to 5 millimeters. The drilling fluid may then be passed over secondary shale shakers to remove smaller drill cuttings. Finally, a portion or all of the drilling fluid may be passed through a centrifuge or other shale shaker with a very fine mesh screen, for the purpose of removing the fines. It is important to remove fines from the drilling fluid in order to maintain the desired flow properties of the active drilling fluid system. Thus, the cuttings wastestream normally consists of larger cuttings from the primary shale shakers and fines from a fine mesh shaker or centrifuge, and may also consist of smaller cuttings from a secondary shale shaker. Before being discharged, the larger cuttings are sometimes sent through another separation device in order to recover additional drilling fluid.

The recovery of SBF from the cuttings serves two purposes. The first is to deliver drilling fluid for reintroduction to the active drilling fluid system, and the second is to minimize the discharge of SBF. The recovery of drilling fluid from the cuttings is a conflicting concern, because as more aggressive methods are used to recover the drilling fluid from the cuttings, the cuttings tend to break down and become fines. The fines are not only more difficult to separate from the drilling fluid, but as stated above they also deteriorate the properties of the drilling fluid. Increased recovery from the cuttings is more problematic for WBF than with SBF because the WBF water-wets the cuttings which encourages the cuttings to disperse and spoil the drilling fluid properties. Therefore, compared to WBF, more aggressive methods of recovering SBF from the cuttings wastestream are practical. These more aggressive methods may be justified for cuttings associated with SBF so as to reduce the discharge of SBF. This, consequently, will reduce the potential to cause anoxia (lack of oxygen) in the receiving sediment as well as reduce the quantity of toxic organic and metallic components of the drilling fluid discharged.

Drill cuttings are typically discharged continuously as they are separated from the drilling fluid in the solids separation equipment. The drill cuttings will also carry a residual amount of adhered drilling fluid. TSS makes up the bulk of the pollutant loadings, and is comprised of two components: the drill cuttings themselves, and the solids in the adhered drilling fluid. The drill cuttings are primarily small bits of stone, clay, shale, and sand. The source of the solids in the drilling fluid is primarily the barite weighting agent, and clays which are added to modify the viscosity. Because the quantity of TSS is so high and consists of mainly large particles which settle quickly, discharge of SBF drill cuttings can cause benthic

smothering and/or sediment grain size alteration resulting in potential damage to invertebrate populations and alterations in benthic community structure.

Additionally, environmental impacts can be caused by toxic, conventional, and nonconventional pollutants adhering to the solids. The adhered SBF drilling fluid is mainly composed, on a volumetric basis, of the synthetic material, or more broadly speaking, oleaginous material. The oleaginous material may also be toxic or bioaccumulate, and it may contain priority pollutants such as polynuclear aromatic hydrocarbons (PAHs). This oleaginous material may cause hypoxia (reduction in oxygen) or anoxia in the immediate sediment, depending on bottom currents, temperature, and rate of biodegradation. Oleaginous materials which biodegrade quickly will deplete oxygen more rapidly than more slowly degrading materials. EPA, however, thinks that fast biodegradation is environmentally preferable to persistence despite the increased risk of anoxia which accompanies fast biodegradation. This is because recolonization of the area impacted by the discharge of SBF-cuttings or OBF-cuttings has been correlated with the disappearance of the base fluid in the sediment, and does not seem to be correlated with anoxic effects that may result while the base fluid is disappearing. In studies conducted in the North Sea, base fluids that biodegrade faster have been found to disappear more quickly, and recolonization at these sites has been more rapid.

As a component of the drilling fluid, the barite weighting agent is also discharged as a contaminant of the drill cuttings. Barite is a mineral principally composed of barium sulfate, and it is known to generally have trace contaminants of several toxic heavy metals such as mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc.

B. Selection of Pollutant Parameters

1. Stock Limitations of Base Fluids

a. *General.*—EPA is proposing to establish BAT and NSPS that would require the synthetic materials and other oleaginous materials which form the base fluid of the SBFs and other non-aqueous drilling fluids to meet limitations on PAH content, sediment toxicity and biodegradation. The technology basis for meeting these limits would be product substitution, or zero discharge based on land disposal or injection if these limits are not met. These parameters are being regulated to control the discharge of certain toxic and nonconventional pollutants. A large range of synthetic, oleaginous, and water miscible materials have been developed for use as base fluids. These stock limitations on the base fluid are intended to encourage product substitution reflecting best available technology wherein only those synthetic materials and other base fluids which minimize potential loadings and toxicity may be discharged.

b. *PAH Content.*—EPA proposes to regulate PAH content of base fluids because PAHs are comprised of toxic priority pollutants. SBF base fluids typically do not contain PAHs, whereas the traditional OBF base fluids of diesel and mineral oil typically contain on the order of 5 to 10 percent PAH in diesel oil and 0.35 percent PAH in mineral oil. The PAHs typically found in diesel and mineral oil include the toxic priority pollutants fluorene, naphthalene, phenanthrene, and others, and nonconventional pollutants such as alkylated benzenes and biphenyls. Thus, this stock limitation would be one component of a rule reflecting the use of the best available technology.

c. *Sediment Toxicity.*—EPA proposes to regulate sediment toxicity in base fluids and SBFs as a nonconventional pollutant parameter, as an indicator for toxic components of base fluids or drilling fluid. Some of the toxic components of the base fluids may include enhanced mineral oils, internal olefins, linear alpha olefins, paraffinic oils, vegetable esters of 2-hexanol and palm kernel oil, and other oleaginous materials. Some of the possible toxic components of drilling fluids may include the same components as the base fluid, and in addition mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc, formation oil contaminants, and other intended or unintended components of the drilling fluid. It has been shown, during EPA's development of the Offshore Guidelines, that establishing limits on toxicity encourages the use of less toxic drilling fluids and additives. Many of the synthetic base fluids have been shown to have lower toxicity than diesel and mineral oil, but among the synthetic and other oleaginous base fluids some are more toxic than others. Today's proposed discharge option includes a sediment toxicity limitation of the SBF's base fluid stock material, as measured by the 10-day sediment toxicity test (ASTM E1367–92) using a natural sediment and *Leptocheirus plumulosus* as the test organism.

Subsequent to this proposal and before the final rule, EPA intends to gather information to determine how to most appropriately control toxicity and solicit comment on these findings. The sediment toxicity test may be altered, for instance, in terms of test organism (other amphipods or possibly a polychaete), sediment type (formulated in place of natural), or length of test (to shorten the 10-day test period). Further, while today's proposal includes a sediment toxicity limitation of the base fluid stock material, the final discharge option to control toxicity might consist of a different option.

EPA would prefer to control sediment toxicity at the point of discharge as opposed to controlling the base fluid. EPA realizes, however, that the sediment toxicity test may be impractical to implement as a discharge requirement due to potential problems in the availability of uniform sediment and other factors affecting test variability. If EPA finds, through subsequent research, that the sediment toxicity test at the point of discharge is both practical and superior to the base fluid toxicity as an indicator of the toxicity of the SBF at the point of discharge, EPA might apply the sediment toxicity test to the SBF at the point of discharge in place of today's proposed method of the sediment toxicity test to the base fluid.

If the sediment toxicity test of neither the SBF at point of discharge nor synthetic base fluid as a stock limitation is found to be practical due to variability, lack of discriminatory power, or other problems, EPA will search for an alternative toxicity test. One candidate is modification to the current SPP toxicity test, or aquatic phase toxicity test. EPA has several concerns with applying the current SPP test to SBFs. EPA has received information from industry sources and testing laboratories that the results from the SPP test applied to SBFs are highly dependent on both the agitation when mixing the seawater with the SBF and the amount and type of emulsifiers in the SBF formulation. Further, results to date show that, compared to the aquatic toxicity test, the sediment toxicity test provides a better correlation with known toxicity effects of the various synthetic and oleaginous base fluids, and the experimental situation more closely mimics the actual fate of the drilling fluid. While EPA does not think that the current SPP test is useful for application to SBFs, modifications to either the method or limitation may render it functional. Thus, EPA intends to investigate the aquatic phase toxicity test as a possible control in the event that the sediment toxicity test of the drilling fluid is impractical and the

sediment toxicity test of the base fluid is either impractical or inadequate to control the toxicity of the SBF at the point of discharge.

EPA intends, therefore, to investigate further the most appropriate test method for controlling toxicity of SBF discharges, and to validate this method. EPA intends to publish any additional data concerning this limitation in a notice prior to publication of the final rule.

d. *Biodegradation.*—EPA proposes to limit biodegradation as an indicator of the extent, in level and duration, of the toxic effect of toxic components of nonconventional pollutants present in the base fluids, e.g., poly alpha olefins, enhanced mineral oils, internal olefins, linear alpha olefins, paraffinic oils, and vegetable ester of 2-hexanol and palm kernel oil. The various SBF base fluids vary widely in biodegradation rate, as measured by the solid phase test and simulated seabed tests. Based on results from seabed surveys at sites where various base fluids have been discharged with drill cuttings, EPA believes that the results from both measurement methods are indicative of the relative rates of biodegradation in the marine environment. In addition, EPA thinks this parameter correlates strongly with the rate of recovery of the seabed where SBF-cuttings have been discharged.

While EPA is proposing to use the solid phase test to measure compliance with the biodegradation limitation, this test is not yet an EPA validated method. In addition to validating the method for the final rule, EPA intends to gather additional data in support of the biodegradation rate limitation. EPA plans to present any additional data it collects towards this limitation in a notice subsequent to today's proposed rule and before the final rule.

e. *Bioaccumulation.*—While not a part of today's proposal, EPA is also considering establishing BAT and NSPS that would require the synthetic materials and other base fluids used in non-aqueous drilling fluids to meet limitations on bioaccumulation potential. The regulated parameters would be the nonconventional and toxic priority pollutants that bioaccumulate. Based on current information, EPA believes that the base fluid controls on PAH content, sediment toxicity, and biodegradation rate being proposed today are sufficient to control bioaccumulation. EPA intends, however, to study the bioaccumulation potential of the various synthetic base fluids for comparison, and subsequently solicit comments on the results if EPA thinks that some measure of bioaccumulation potential is needed to control adequately the SBF-cuttings wastestream.

2. Discharge Limitations

a. *Free Oil.*—Under BPT and BCT limitations for SBF-cuttings, EPA would retain the prohibition on the discharge of free oil as determined by the static sheen test. Under this prohibition, drill cuttings may not be discharged when the associated drilling fluid would fail the static sheen test defined in Appendix 1 to 40 CFR Part 435, Subpart A. The prohibition on the discharge of free oil is intended to minimize the formation of sheens on the surface of the receiving water. The regulated parameter of the no free oil limitation would be the conventional pollutants oil and grease which separate from the SBF and cause a sheen on the surface of the receiving water.

The free oil discharge prohibition does not control the discharge of oil and grease and crude oil contamination in SBFs as it would in WBFs. With WBFs, oils which may be present (such as diesel oil, mineral oil, formation oil, or other oleaginous materials) are present as the discontinuous phase. As such these oils are free to rise to the surface of the receiving water where they may appear as a film or sheen upon or discoloration of the surface. By contrast, the oleaginous matrices of SBFs do not disperse in water. In addition they are weighted with barite, which causes them to sink as a mass without releasing either the oleaginous materials which comprise the SBF or any contaminant formation oil. Thus, the test would not identify these pollutants. However, a portion of the synthetic material comprising the SBF may rise to the surface to cause a sheen. These components that rise to the surface fall under the general category of oil and grease and are considered conventional pollutants. Therefore, the purpose of the no free oil limitation of today's proposal is to control the discharge of conventional pollutants which separate from the SBF and cause a sheen on the surface of the receiving water. The limitation, however, is not intended to control formation oil contamination nor the total quantity of conventional pollutants discharged.

b. *Formation Oil Contamination.*—Formation oil contamination of the SBF associated with the cuttings would be limited under BAT and NSPS. Formation oil is an ''indicator'' pollutant for the many toxic and priority pollutant components present in formation (crude) oil, such as aromatic and polynuclear aromatic hydrocarbons. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. (See Development Document Chapter VII). The primary limitation is based on a fluorescence test. This test is considered an appropriately ''weighted'' test because crude oils containing more toxic aromatic and PAH components tend to show brighter fluorescence and hence noncompliance at a lower level of contamination. Since fluorescence is a relative brightness test, gas chromatography with mass spectroscopy detection (GC/MS) is provided as a baseline method before the drilling fluid is delivered for use, and is also available as an assurance method when the results from the fluorescence compliance method are in doubt.

c. *Retention of SBF on Cuttings.*—The retention of SBF on drill cuttings would be limited under BAT and NSPS. This limitation controls the quantity of SBF discharged with the drill cuttings. Both nonconventional and priority toxic pollutants would be controlled by this limitation. Nonconventionals include the SBF base fluids, such as vegetable esters, internal olefins, linear alpha olefins, paraffinic oils, mineral oils, and others. This limitation would also limit the toxic effect of the drilling fluid and the persistence or biodegradation of the base fluid. Several toxic and priority pollutant metals are present in the barite weighting agent, including arsenic, chromium, copper, lead, mercury, nickel, and zinc, and nonconventional pollutants such as aluminum and tin.

The emulsifying and wetting agents of the SBF would also be controlled by limiting the amount of SBF discharged. EPA solicits information concerning the composition of the wetting and emulsifying agents so that they can be classified as conventional, nonconventional, or toxic pollutants.

Today's proposed rule uses the retort method to determine compliance with the limit. The limit is expressed as percentage base fluid on wet cuttings (weight/weight), averaged over the well sections drilled with SBF. This method has not yet been validated by EPA. Further, EPA is currently researching a mass balance method as an alternative method to determine the quantity of SBF discharged. After EPA has gathered sufficient data using the two methods in a comparative analysis, EPA intends to validate the preferred method and solicit comment concerning the method to be applied for the final rule.

3. Maintenance of Current Requirements

EPA would retain the existing BAT and NSPS limitations on the stock barite of 1 mg/kg mercury and 3 mg/kg

cadmium. These limitations would control the levels of toxic pollutant metals because cleaner barite that meets the mercury and cadmium limits is also likely to have reduced concentrations of other metals. Evaluation of the relationship between cadmium and mercury and the trace metals in barite shows a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, titanium and zinc. (See the Offshore Development Document in Section VI).

EPA also would retain the BAT and NSPS limitations prohibiting the discharge of drilling wastes containing diesel oil in any amount. Diesel oil is considered an ''indicator'' for the control of specific toxic pollutants. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. Diesel oil may contain from 3 to 10 percent by volume PAHs, which constitute the more toxic components of petroleum products.

C. Regulatory Options Considered for SBFs Not Associated With Drill Cuttings

Today EPA proposes, under BPT, BCT, BAT, and NSPS, zero discharge for SBFs not associated with drill cuttings. This option is technically available and economically achievable with equipment commonly used. It is also current industry practice due to the value of SBFs recovered and reused. Since this option reflects current industry practice, it has no non-water quality environmental impacts.

Industry sources have indicated that at times, there may be minor drips or spills of SBFs that occur on the platform. EPA is considering whether these discharges should be governed by the zero discharge requirement, or whether to view the zero discharge requirements as being limited to discharge of whole drilling fluids, and allowing unintentional drips and spills to be treated as miscellaneous wastes. EPA solicits comment on this approach. EPA thinks that the best way to control these discharges would be through the use of BMPs and solicits comment on what types of BMPs would be effective for controlling these discharges and whether such BMPs should be part of this effluent guideline or be applied by the permit authority.

D. Regulatory Options Considered for SBFs Associated With Drill Cuttings

EPA considered two options for today's proposed rule for SBFs associated with drill cuttings, or SBF-cuttings: a discharge option and a zero discharge option. EPA has selected the discharge option as the basis for today's proposal. As detailed above, this discharge option controls under BAT and NSPS the stock base fluid through limitations on PAH content, sediment toxicity, and biodegradation rate, and controls at the point of discharge under BPT and BCT sheen formation and under BAT and NSPS formation oil content and quantity of SBF discharged. The discharge option maintains current requirements of stock limitations on barite of mercury and cadmium, and the diesel oil discharge prohibition. EPA at this time thinks that all of these components are essential for appropriate control of the SBF cuttings wastestream.

Although not the basis for today's proposal, EPA considered zero discharge as an option for BPT, BCT, BAT, and NSPS. Under zero discharge all pollutants would be controlled in SBF discharges. This option was clearly technically feasible and economically achievable because in the past SBFs did not exist, and industry was able to operate using only the traditional non-dischargeable OBFs based on diesel oil and mineral oil.

EPA presently rejects zero discharge as the preferred option because it would result in unacceptable non-water quality environmental impacts. If EPA were to choose zero discharge for SBF-cuttings, operators would not have an incentive to use SBFs since they are more expensive than OBFs. Thus, if EPA requires zero discharge, OBF-cuttings would continue to be injected or shipped to shore for land disposal. EPA's analysis shows that under this option as compared to the discharge option, for existing and new sources combined, there would be 172 million pounds annually of OBF-cuttings shipped to shore for disposal in non-hazardous oilfield waste sites and 40 million pounds annually injected, with associated fuel use of 29,000 BOE and annual air emissions of 450 tons. EPA believes these impacts far outweigh the water impacts associated with these discharges detailed in Section VIII of this preamble. EPA's current analysis shows that the impacts of these discharges to water are of limited scope and duration, particularly if EPA controls the discharges of SBFs to the best environmental performers that also meet the technical requirements needed to drill. By contrast, the landfilling of OBF-cuttings is of a longer term duration and associated pollutants may effect ambient air, soil, and groundwater quality. For these reasons, under EPA's authority to consider the non-water quality environmental impacts of its rule, EPA rejects zero discharge of SBF-cuttings.

Nonetheless, while discharge with adequate controls is preferred over zero discharge, discharge with inadequate controls is not preferred over zero discharge. EPA believes that to allow discharge of SBF-cuttings, there must be appropriate controls to ensure that EPA's discharge limitations reflect the ''best available technology'' or other appropriate level of technology. EPA has worked with industry to address the determination of PAH content, sediment toxicity, biodegradation, bioaccumulation, the quantity of SBF discharged, and formation oil contamination. The successful completion of these efforts is necessary for EPA to continue to reject zero discharge.

E. BPT Technology Options Considered and Selected

As previously discussed, Section 304(b)(1)(A) of the CWA requires EPA to identify effluent reductions attainable through the application of ''best practicable control technology currently available for classes and categories of point sources.'' Generally, EPA determines BPT effluent levels based upon the average of the best existing performances by plants of various sizes, ages, and unit processes within each industrial category or subcategory. In industrial categories where present practices are uniformly inadequate, however, EPA may determine that BPT requires higher levels of control than any currently in place if the technology to achieve those levels can be practicably applied. See *A Legislative History of the Federal Water Pollution Control Act Amendments of 1972,* U.S. Senate Committee of Public Works, Serial No. 93–1, January 1973, p. 1468.

In addition, CWA Section 304(b)(1)(B) requires a cost assessment for BPT limitations. In determining the BPT limits, EPA must consider the total cost of treatment technologies in relation to the effluent reduction benefits achieved. This inquiry does not limit EPA's broad discretion to adopt BPT limitations that are achievable with available technology *unless* the required additional reductions are ''wholly out of proportion to the costs of achieving such marginal level of reduction.'' See *Legislative History,* op. cit. p. 170. Moreover, the inquiry does not require the Agency to quantify benefits in monetary terms. See e.g. *American Iron and Steel Institute* v. *EPA,* 526 F. 2d 1027 (3rd Cir., 1975).

In balancing costs against the benefits of effluent reduction, EPA considers the volume and nature of expected

discharges after application of BPT, the general environmental effects of pollutants, and the cost and economic impacts of the required level of pollution control. In developing guidelines, the Act does not require consideration of water quality problems attributable to particular point sources, or water quality improvements in particular bodies of water. Therefore, EPA has not considered these factors in developing the limitations being proposed today. See *Weyerhaeuser Company* v. *Costle*, 590 F. 2d 1011 (D.C. Cir. 1978).

EPA today proposes BPT effluent limitations for the cuttings contaminated with SBF and other non-aqueous drilling fluids. The BPT effluent limitations proposed today would control free oil as a conventional pollutant. The limitation is no free oil as measured by the static sheen test, performed on SBF separated from the cuttings.

In setting the no free oil limitation, EPA considered the sheen characteristics of currently available SBFs. Since this requirement is currently met by dischargers in the Gulf of Mexico, EPA anticipates no additional costs to the industry to comply with this limitation.

EPA also considered a BPT level of control for the quantity of SBF discharged with the cuttings consisting of improved use of currently existing shale shaker equipment. However, EPA did not have enough information to establish BPT beyond current performance. Further, EPA is not setting a BPT limit based on current performance because operators already have incentive to recover as much SBFs as possible through the optimization of existing equipment due to the value of the SBFs. Therefore, a BPT limitation based on the current equipment, and as it is currently used, would not have any practical effect on the quantity of SBF discharged with the cuttings. Further, given that the BAT and NSPS limitations would be more stringent and control the conventional pollutants in addition to the non-conventional and toxic pollutants, EPA saw no reason to expend time and resources to develop a different, less restrictive BPT limit.

F. BCT Technology Options Considered and Selected

In July 1986, EPA promulgated a methodology for establishing BCT effluent limitations. EPA evaluates the reasonableness of BCT candidate technologies—those that are technologically feasible—by applying a two-part cost test: (1) a POTW test; and (2) an industry cost-effectiveness test.

EPA first calculates the cost per pound of conventional pollutant removed by industrial dischargers in upgrading from BPT to a BCT candidate technology and then compares this cost to the cost per pound of conventional pollutants removed in upgrading POTWs from secondary treatment. The upgrade cost to industry must be less than the POTW benchmark of $0.25 per pound (in 1976 dollars).

In the industry cost-effectiveness test, the ratio of the incremental BPT to BCT cost divided by the BPT cost for the industry must be less than 1.29 (i.e., the cost increase must be less than 29 percent).

In today's proposal, EPA is proposing to establish a BCT limitation of no free oil equivalent to the BPT limitation of no free oil as determined by the static sheen test. In developing BCT limits, EPA considered whether there are technologies (including drilling fluid formulations) that achieve greater removals of conventional pollutants than proposed for BPT, and whether those technologies are cost-reasonable according to the BCT Cost Test. EPA identified no technologies that can achieve greater removals of conventional pollutants than proposed for BPT that are also cost-reasonable under the BCT Cost Test, and accordingly EPA proposes BCT effluent limitations equal to the proposed BPT effluent limitations guidelines.

G. BAT Technology Options Considered and Selected

EPA today proposes BAT effluent limitations for the cuttings contaminated with SBFs. The BAT effluent limitations proposed today would control the stock base fluids in terms of PAH content, sediment toxicity, and biodegradation. Controls at the point of discharge include formation oil contamination and the quantity of SBF discharged. This level of control has been developed taking into consideration the availability and cost of oleaginous (SBF) base fluids in terms of PAH content, sediment toxicity, and biodegradation rate; the frequency of formation oil contamination at the control level; the performance and cost of equipment to recover SBF from the drill cuttings. The technical availability and economic achievability of today's proposed limitations is discussed below by regulated parameter.

1. Stock Base Fluid Technical Availability and Economic Achievability

a. *Introduction.*—As SBFs have developed over the past few years, the industry has come to use mainly a few primary base fluids. These include the vegetable esters, internal olefins, linear alpha olefins, and poly alpha olefins. Thus, these are the base fluids for which EPA has data and costs to develop the effluent limitations of today's proposed rule. In this document, vegetable ester means a monoester of 2-ethylhexanol and saturated fatty acids with chain lengths in the range C_8-C_{16}, internal olefin means a series of isomeric forms of C_{16} and C_{18} alkenes, linear alpha olefin means a series of isomeric forms of C_{14} and C_{16} monoenes, and poly alpha olefins means a mix mainly comprised of a hydrogenated decene dimer $C_{20}H_{62}$ (95%), with lesser amounts of $C_{30}H_{62}$ (4.8%) and $C_{10}H_{22}$ (0.2%). EPA also has data on other oleaginous base fluids, such as enhanced mineral oil, paraffinic oils, and the traditional OBF base fluids mineral oil and diesel oil.

The stock base fluid limitations presented below are based on currently available base fluids, and the limitations would be achievable through product substitution. EPA anticipates that the currently available and economically achievable base fluids meeting all requirements would include vegetable esters and internal olefins. EPA also solicits data on linear alpha olefins and certain paraffinic oils to determine whether these base fluids are comparable in terms of sediment toxicity, biodegradation, and bioaccumulation.

b. *PAH Content Technical Availability.*—Today's proposed limitation of PAH content is 0.001 percent, or 10 parts per million (ppm), weight percent PAH expressed as phenanthrene. This limitation is based on the availability of base fluids that are free of PAHs and the detection of the PAHs by EPA Method 1654A. EPA's proposed PAH content limitation is technically available. Producers of several SBF base fluids have reported to EPA that their base fluids are free of PAHs. The base fluids which suppliers have reported are free of PAHs include linear alpha olefins, internal olefins, vegetable esters, certain enhanced mineral oils, synthetic paraffins, certain non-synthetic paraffins, and others. See the Development Document, Chapter VII. Compliance with the BAT and NSPS stock limitations on PAH content may be achieved by product substitution.

c. *Sediment Toxicity Technical Availability.*—EPA is today proposing a sediment toxicity stock base fluid limitation that would allow only the discharge of SBF-cuttings using base fluids as toxic or less toxic, but not more toxic, than C_{16}-C_{18} internal olefin.

Alternatively, this limitation could be expressed as the LC_{50} of the base fluid minus the LC_{50} of the C_{16}-C_{18} internal olefin shall not be less than zero. Based on information available to EPA at this time, the only base fluids which would attain this limitation are the internal olefins and vegetable esters.

EPA finds this limit to be technically available because information in the rulemaking record supports that internal olefin SBFs and vegetable ester SBFs together have performance characteristics enabling them to be used in a wide variety of drilling situations offshore. Marketing data given to the EPA shows that, at least for certain of the major drilling fluid suppliers, internal olefin SBFs are currently the most popular SBFs used in the Gulf of Mexico.

Various researchers have performed toxicity testing of the synthetic base fluids with the 10-day sediment toxicity test (EPA/600/R–94/025) using a natural sediment and *Leptocheirus plumulosus* as the test organism. The synthetic base fluids have been shown to have lower toxicity than diesel and mineral oil, and among the synthetic and other oleaginous base fluids some are more toxic than others. For example, Still et al. reported the following 10-day LC_{50} results, expressed as mg base fluid/Kg dry sediment: diesel LC_{50} of 850, enhanced mineral oil LC_{50} of 251, internal olefin LC_{50} of 2,944, and poly alpha olefin LC_{50} of 9,636. A higher LC_{50} value means the material is less toxic. Similar results, with the same trend in toxicity in the base fluids above, have been reported by Hood et al. Candler et al. performed the 10-day sediment toxicity test with the amphipod *Ampelicsa abdita* in place of *Leptocheirus plumulosus*, and again obtained very similar results as follows: diesel LC_{50} of 879, enhanced mineral oil LC_{50} of 557, internal olefin LC_{50} of 3,121, and PAO LC_{50} of 10,680.

None of these researchers reported sediment toxicity values for vegetable esters. Recently, industry has evaluated a number of base fluids including vegetable esters. While the absolute values are not comparable because the tests were performed on the drilling fluid and not just the base fluid, the results showed the vegetable ester to be less toxic than the internal olefin.

Researchers in the United Kingdom and Norway investigating effects in the North Sea have conducted sediment toxicity tests on other organisms, namely *Corophium volutator* and *Abra alba*. Similar trends were seen in the measured toxicity, with vegetable ester having very low sediment toxicity (very high LC_{50}), poly alpha olefin having a mid range toxicity, and internal olefin having a higher toxicity, in this comparison.

While the poly alpha olefins were found to have the lowest toxicity of the measured base fluids (excludes vegetable esters), EPA did not base the toxicity limitation on poly alpha olefins because, as presented below, they biodegrade much more slowly and so are unlikely to pass the biodegradation limitation. EPA intends to generate and gather additional data comparing the toxicity of the various base fluids, especially to compare the vegetable ester toxicity with that of the olefins since, at this time, directly comparable data is not available. If vegetable esters are found to have significant reduced toxicity compared to the other base fluids, EPA may choose to base the toxicity limitation on vegetable esters. EPA has concerns, however, over the technical performance and possible non-water quality implications with the use of vegetable ester as the only technology available to meet the stock base fluid limitations, as discussed below under biodegradation.

As an alternative, EPA solicits comment on a numeric limitation of a minimum LC_{50} of 2,600 mg base fluid/Kg dry sediment as an appropriate level of control, based on the toxicity of C_{16} – C_{18} internal olefins as determined by the 10-day sediment toxicity test using *Leptocheirus plumulosus* as the test organism. If EPA pursues this approach, EPA expects that it may need to revise this numeric limitations due to the variability currently experienced with this test.

d. *Biodegradation Rate Technical Availability.*—Today's proposed limitation of biodegradation rate for the base fluid, as determined by the solid phase test, is equal to or faster than the rate of a C_{16}-C_{18} internal olefin. Alternatively, this limitation could be expressed as the percent of the base fluid degraded at 120 days minus the percent of C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero. With this limitation the base fluids currently available for use include vegetable ester, linear alpha olefin, internal olefins, and possibly certain linear paraffins. Combined with the other stock base fluid limitations of PAH content and sediment toxicity, the base fluids for which EPA has data that would attain all three limitations are internal olefins and vegetable esters.

EPA finds this limit to be technically available because information in the rulemaking record supports that internal olefin SBFs and vegetable ester SBFs together have performance characteristics to address the broad variety of drilling situations found offshore.

As an alternative to today's proposal, EPA solicits comment on a numeric limitation of a minimum biodegradation rate of 68 percent base fluid dissipation at 120 days for the standardized solid phase test. If EPA pursues this approach, EPA expects that it may need to revise this numeric limitations as additional test results are generated.

As with the sediment toxicity test presented above, due to the lack of data from the biodegradation test EPA again intends to propose a limitation based on comparative testing rather than propose a numerical limitation. Therefore, if SBFs based on fluids other than internal olefins and vegetable esters are to be discharged with drill cuttings, data showing the biodegradation of the base fluid should be presented with data, generated in the same series of tests, showing the biodegradation of the internal olefin as a standard. EPA prefers this approach rather than set a numerical limitation at this time because of the small amount of data available to EPA upon which to base a numerical limitation. EPA sees this as an interim solution to the problem of having insufficient information at the time of this proposal to provide a numerical limitation, in that it still provides a limitation based on the performance of available technologies.

Rates of biodegradation for synthetic and mineral oil base fluids have been determined by both the solid phase and the simulated seabed test, and the relative rates of biodegradation among these two tests agree. These tests have found that, the order of degradation, from fastest to slowest, is as follows: vegetable ester > linear alpha olefin > internal olefin > linear paraffin > mineral oil > poly alpha olefin.

EPA has selected the internal olefin as the basis for the biodegradation rate limitation instead of the vegetable ester for two reasons: technical performance and non-water quality environmental impacts. Industry representatives have reported that SBFs using esters currently on the market today are not adequate choices for most deepwater drilling applications. Reportedly, the available esters thicken considerably at the cold temperatures encountered in the riser in deep water. This thickening can cause excessive pressure surges when attempting to re-initiate circulation. These pressure surges can result in breakdown of exposed formations resulting in severe SBF losses to the destabilized formations. In addition to SBF losses, pressure surges can destabilize the formation to the extent of hole collapse and loss of any

drilling tools downhole. EPA solicits comment concerning the maximum depth at which vegetable ester SBFs are practical, the development on new esters with lower viscosity, and if special systems, such as subsea pumping systems, ameliorate the pumping difficulties.

Cost is a factor in encouraging the use of SBFs in place of OBFs. Industry representatives have told EPA that vegetable ester SBF costs about twice as much as internal olefin SBF. EPA believes that if the lower cost internal olefin SBFs can be discharged, then more wells currently drilled with OBF would be encouraged to convert to SBF than if only the more expensive vegetable ester SBFs were available for discharge. This conversion is preferable for the improvements in non-water quality environmental impacts (see section VII below). If future research shows that vegetable esters have a significantly reduced toxicity in addition to the proven faster rate of biodegradation, EPA may consider more stringent stock base fluid limitations to favor the use of vegetable ester SBFs for the final rule.

e. *Economic Achievability of Stock Base Fluid Controls.*—EPA finds that the proposed stock base fluid controls are economically achievable. Industry representatives have told EPA that while the synthetic base fluids are more expensive than diesel and mineral oil base fluids, the savings in discharging the SBF-cuttings versus land disposal or reinjection of OBF-cuttings more than offsets the increased cost of SBFs. Thus, it reportedly costs less for operators to invest in the more expensive SBF provided it can be discharged. The stock base fluid limitations proposed above allow use of the currently popular SBFs based on internal olefins ($195/bbl) and vegetable esters ($380/bbl). For comparison, diesel oil-based drilling fluid costs about $65/bbl, and mineral oil-based drilling fluid costs about $75/bbl. According to industry sources, currently in the Gulf of Mexico the most widely used and discharged SBFs are, in order of use, based on internal olefins, linear alpha olefins, and vegetable esters. Since the stock limitations allow the continued use of the preferred internal olefin and vegetable ester SBFs, EPA attributes no additional cost due to the stock base fluid requirements other than monitoring (testing and certification) costs. EPA expects that these monitoring costs will fall upon the base fluid suppliers as a marketing cost. As further described in Section XII, EPA anticipates that PAH monitoring would occur batchwise, and sediment toxicity and biodegradation monitoring would occur once annually per synthetic base fluid per supplier.

Pursuant to EPA's further research into sediment toxicity and biodegradation, EPA may propose limits for the final rule that are different than the limits proposed today. If the limits were to allow only more expensive SBFs, such as the vegetable ester, EPA would likely estimate a cost to comply with the stock base fluid limits for those operators who currently use and discharge the less expensive SBFs, for instance those based on internal olefins.

2. Discharge Limitations Technical Availability and Economic Achievability

a. *Formation Oil Contamination of SBF-Cuttings.*—Today's proposed formation oil contamination limitation of the SBF adhered to the drill cuttings is ''weighted'' to detect contamination by highly aromatic formation oils at lower concentrations than formation oils with lower aromatic contents. Under the proposed limitation approximately 5 percent of all (all meaning a large representative sampling) formation oils would fail (not comply) at 0.1 percent contamination and 95 percent of all formation oils will fail at 1.0 percent contamination. The majority of formation oils would cause failure when present in SBFs at a concentration of about 0.5 percent (vol/vol).

EPA is proposing two methods for the determination of formation oil in SBFs. Analysis by gas chromatography with mass spectroscopy detection (GC/MS) would apply to any SBF being shipped offshore for drilling to allow discharge of the associated cuttings. During drilling, the SBF would be required to comply with the limitation of formation oil contamination as determined by the reverse phase extraction (RPE) method. SBFs found to be non-compliant by the RPE method could, at the operators discretion, be confirmed by testing with the GC/MS method. Results from the GC/MS method would supersede those of the RPE method.

EPA intends that the limitation proposed on formation (crude) oil contamination in SBF is no less stringent that the limitation imposed on WBF through the static sheen test. A study concerning this issue found that in WBF, the static sheen test detected formation oil contamination in WBF down to 1 percent in most cases, and down to 0.5 percent in some cases.

Currently, only a very small percent of WBF cannot be discharged due to presence of formation oil as determined by the static sheen test. EPA solicits information regarding the frequency of formation oil contamination at this level of control. EPA has received some anecdotal information to the effect that far less than one percent of SBF cuttings would not be discharged due to formation oil contamination at this level of control. Based on the available information, EPA believes that only a very minimal amount of SBF will be non-compliant with this limitation and therefore be required to dispose of SBF-cutting onshore or by injection. EPA thus finds that this limitation is technically available. EPA also finds this option to be economically achievable because there is no reason why formation oil contamination would occur more frequently under this rule than under the current rules which industry can economically afford. For calculation purposes, EPA has determined that no costs are associated with this requirement other than monitoring and reporting costs, which are minimal costs for this test for this industry.

b. *Retention of SBF on Cuttings.*—This limitation considers the technical availability of methods to recover SBF from the cuttings wastestream. EPA evaluated the performance of several technologies to recover SBF from the cuttings wastestream and their costs, as detailed in the Development Document. EPA also considered fuel use, safety, and other considerations.

The solids control system typically consists of, at a minimum, a primary shale shaker to remove the larger cuttings. Typically, all or a portion of the drilling fluid is then passed through a secondary shale shaker or ''mud cleaner'' to remove the small particle cuttings, or ''fines,'' before being recirculated to the active mud system. Greater efficiencies in the use of these currently used technologies through reduced loadings and more even flow across the screens, better maintenance of the screens, and better integration of the solids control system would help operators achieve these proposed discharge limitations. An ancillary or alternative method to reduce SBF discharges is to retain the fines for on shore disposal. Because of their small size and large surface area, the fines retain more drilling fluid than an equal amount of larger cuttings coming off the shale shakers. Therefore, while the bulk of the cuttings may be discharged, retaining the fines for on shore disposal can be used to disproportionately reduce the overall discharges of SBF.

The American Petroleum Institute (API) performed a study in 1997 which gathered data on SBF retention on drill cuttings. Data gathered in the study show the long term average retention

rate of SBF on cuttings, weighted by hole volume, is 10.6 percent from the primary shale shaker and 15.0 percent from the secondary shale shaker, expressed as weight synthetic base fluid per weight of wet cuttings. Industry representatives further estimated that the cuttings from the primary shale shaker comprise 80 percent of the total cuttings wastestream, and the remaining 20 percent is removed by either the secondary shale shaker or other devices to remove very small cuttings, or fines. EPA used this information to calculate a long term average weighted retention of 11.5 percent base fluid on wet cuttings using the current technologies employed in the Gulf of Mexico.

Recently, in the wake of the development of SBFs and discharge limitations in the North Sea, new cuttings cleaning devices have been developed which reduce SBF retained on the cuttings. An effective device consists of a conically shaped vibrating centrifuge, which removes recycle-grade SBF from the cuttings coming off the primary shale shakers. EPA selected this conical vibrating centrifuge as the model technology on which to base its performance and cost calculations. The manufacturer of the device has supplied EPA with detailed performance data and some cost information of this device. The performance has been confirmed by one operator, showing retention data for twelve wells and comparing the vibrating centrifuge with shale shaker technology. In addition, EPA was invited by an operator in the Gulf of Mexico to observe the operation of the vibrating centrifuge. EPA has learned that the operator has written a report concerning the operation of this SBF recovery device, but this report has not been made available to EPA. The operator has informed EPA as to the cost of implementing the vibrating centrifuge, and EPA used this cost information in determining the total cost of implementation. EPA is aware of at least one other company that makes a similar centrifugal device to recover SBFs from drill cuttings, although EPA has not received performance or costs for this machine.

The limitation proposed today for retention of SBF is 10.2 percent base fluid on wet cuttings (weight/weight), averaged by hole volume over the well sections drilled with SBF. Those portions of the cuttings wastestream that are retained for no discharge are factored into the weighted average with a retention value of zero. The limit assumes that SBF-cuttings processed by the vibrating centrifuge technology comprise 80 percent of the wastestream while the remaining 20 percent is comprised of SBF-cuttings from the secondary shale shaker. Thus, from the available data EPA determined that the retention attained for 95 percent of volume-weighted well averages was 7.22 for the vibrating centrifuge and 22.0 for the secondary shale shakers. Applying the assumption of an 80/20 split between the two wastestreams, EPA determined the weighted average retention regulatory limit of 10.2 percent.

Based on current performance of the vibrating centrifuge technology, 95 percent of all volume-weighted average values for retention of drilling fluids over the course of drilling a well are expected to be less than the proposed limit. Some, but not all, of the variability between wells is due to factors under the control of the operators. EPA believes that the proposed limit can be met at all times by providing better attention to the operation of the technology and by keeping track of the weighted average for retention as the well is being drilled. If the trend in weighted average retention appears to the operator as if the average retention for a particular well will exceed the limitation prior to completion of the well then EPA recommends that the operator retain some or all of the remaining cuttings for no discharge. This is feasible because retention of SBF on drill cuttings is generally low in the early stages of drilling a well and it increases as the well goes deeper.

EPA used the same statistical analysis to determine the long term average retention values. These values were used for cost and loadings calculations. For the vibrating centrifuge and the secondary shale shaker, respectively, EPA determined that the long term between-well average percent retention of SBF on cuttings was 5.14 and 15.00. Applying the assumption of an 80/20 split between the two wastestreams, the long term average value for cost and loading calculations is 7.11 percent SBF retained on wet cuttings. Cost and loadings calculations also assumed 7.5 percent washout of the well bore.

EPA finds that a well-average limit of 10.2 percent base fluid on wet cuttings is economically achievable. According to EPA's analysis, in addition to reducing the discharge of SBFs associated with the cuttings, EPA estimates that this control will result in a net savings of $5.0 MM. This savings results because the value of the SBF recovered is greater than the cost of implementation of the technology. This analysis is presented in Section IX of today's notice, and in greater detail in the Development Document.

EPA thinks that this regulatory limitation is necessary to both hasten and broaden the use of improved SBF recovery devices, even though industry may be inclined to implement the SBF recovery technology to save valuable SBF irrespective of the limitation. There could be several reasons why industry does not already use the model SBF recovery technology even though, in EPA's assessment, it saves the operator money. For one, market acceptance and market penetration of the vibrating centrifuge could be a reason. The vibrating centrifuge recovery technology is a new technology that was developed in the North Sea and has only been demonstrated a few times in the United States. Secondly, the cost and resources devoted to retrofitting might only benefit a small portion of the wells drilled by an operator. This is because only a small fraction of wells, about 13 percent in EPA's analysis, are drilled with SBFs. To counter this, however, is the fact that most SBF wells are concentrated in the deep water. EPA projects that 75 percent of all wells drilled in the deepwater would use SBFs. In addition, retrofitting costs and market forces would encourage the dedication of drill platforms equipped with improved SBF recovery technology to the drilling of SBF wells. The use of improved SBF recovery devices in the North Sea is a case in point. Operators have reported to EPA that in the North Sea they were reluctant to use improved SBF recovery devices, and eventually did so only in response to more stringent regulatory requirements. These operators report that their total cost to drill an SBF well actually went down as they implemented the improved SBF recovery devices because of the value of the SBF recovered.

H. NSPS Technology Options Considered and Selected

The general approach followed by EPA for developing NSPS options was to evaluate the best demonstrated SBFs and processes for control of priority toxic, nonconventional, and conventional pollutants. Specifically, EPA evaluated the technologies used as the basis for BPT, BCT and BAT. The Agency considered these options as a starting point when developing NSPS options because the technologies used to control pollutants at existing facilities are fully applicable to new facilities.

EPA has not identified any more stringent treatment technology option which it considered to represent NSPS level of control applicable to the SBF-cuttings wastestream. Further, EPA has made a finding of no barrier to entry based upon the establishment of this

level of control for new sources. See section X, Economic Analysis. Therefore, EPA is proposing that NSPS be established equivalent to BPT and BAT for conventional, priority, and nonconventional pollutants.

VII. Non-Water Quality Environmental Impacts of Proposed Regulations

A. Introduction and Summary

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems. Under sections 304(b) and 306 of the CWA, EPA is required to consider these non-water quality environmental impacts (including energy requirements) in developing effluent limitations guidelines and NSPS. In compliance with these provisions, EPA has evaluated the effect of this proposed regulation on air pollution, energy consumption, solid waste generation and management, consumptive water use, safety, and vessel traffic.

Based on this evaluation, EPA currently prefers the discharge option over the zero discharge option because of the non-water quality environmental impacts that would occur with zero discharge, compared to the water quality impacts that would occur with discharge as controlled by this proposed rule. Thus, non-water quality environmental impacts are a major consideration for this rule because of the nature of the wastes and where the wastes are generated and disposed.

If SBF-cuttings cannot be discharged, cuttings from SBF wells would have to be transported to shore for treatment and disposal, or made into a slurry and injected on-site. In this case, EPA assumes that most operators will not use SBF in place of OBF, because SBFs cost more than OBFs. On the other hand, if SBF-cuttings can be discharged, not only are non-water quality environmental impacts from current SBF wells drastically reduced, but EPA also estimates that some OBF wells would convert to SBF, further decreasing these impacts. EPA estimates that in the Gulf of Mexico (GOM) 20 percent of OBF wells will convert to SBF wells. EPA also estimates that these GOM OBF wells are in shallow water (less than 1000 feet). In deep water, EPA assumes that those wanting to use SBFs are already doing so and therefore these facilities are not considered to yield non-water quality environmental impacts reductions. In offshore California and Cook Inlet, Alaska, EPA assumes that all OBF wells will convert, because of the greater expense of OBF-cuttings discharge and an ever greater concern for non-water quality environmental impacts in these areas as compared to the GOM. For example, disposal of OBF-cuttings in Cook Inlet, Alaska, would likely require the barging of the waste to the lower 48 States. Air quality in California is a continuing concern and therefore there is pressure to keep air emissions from oil and gas drilling activities in the neighboring offshore waters at a minimum.

In total, for existing and new sources under the discharge option, EPA estimates that air emissions would be reduced by 72 tons per year, based on OBF facilities switching to SBF. If the zero discharge option was selected, however, air emissions would increase by 378 tons per year, based on SBF to OBF conversion. Therefore, in moving from the zero discharge option to the discharge option, air emissions would be reduced by 450 tons per year. In addition, EPA estimates than 29,359 BOE less fuel would be used.

Other favorable non-water quality environmental impacts occur with the elimination of the long term disposal of OBF-cuttings on shore, because the pollutants present in OBF-cuttings may affect ambient air, soil, and groundwater quality. EPA estimates that allowing discharge of SBF-cuttings compared to zero discharge would decrease the amount of OBF-cuttings disposed at land based facilities by 172 MM pounds annually, and the amount injected by 40 MM pounds. The methodology used to arrive at these numbers is described in the sections which follow, and the results are discussed in more detail.

In consideration of the many non-water quality benefits with SBF-discharge, EPA currently prefers to allow the controlled discharge of SBF-cuttings despite some additional SBF-cuttings discharges that may occur as a result of this rule. EPA's authority to consider the non-water quality environmental impacts of its rule, therefore, forms the primary basis in EPA's rejection of zero discharge of SBF-cuttings.

B. Method Overview

EPA estimated annual energy consumption (i.e., fuel usage), air emissions, and solid waste generation rates from information on model well characteristics and current drilling activity gathered from industry, State, and Federal agency sources. This framework is based upon the model well, well count, and control technology data that is detailed in the compliance cost and pollutant reductions discussions of today's notice (Section IX). EPA's calculations are based on the following projections: wells drilled with SBF in the Gulf of Mexico currently discharge SBF-cuttings containing an average 11 percent by weight synthetic base fluid; under the discharge option SBF-cuttings would retain an average 7 percent base fluid on cuttings; and of the wells drilled with OBF 80 percent practice zero discharge by hauling OBF-cuttings to shore for land-based disposal, and the remaining 20 percent inject on-site. In the context of the non-water quality environmental impacts analysis, SBF wells using standard solids control equipment and discharging SBF-cuttings at 11 percent retention are defined as the baseline. Increases or decreases in non-water quality environmental impacts are compared to this baseline. For example, current OBF wells that EPA projects would convert to SBF in the discharge option are assigned baseline impacts because these wells use energy consuming technologies (i.e., transportation for disposal or injection) beyond standard solids control equipment.

After establishing baseline impacts, EPA calculated impacts resulting from compliance with the proposed discharge and zero discharge options, details of which are given in the following discussions. EPA then calculated the incremental impacts by subtracting the compliance impacts from the baseline impacts.

The discussions below adopt the following acronyms for the four model well types developed for well-specific analyses: DWD (deep-water development), DWE (deep-water exploratory), SWD (shallow-water development), and SWE (shallow-water exploratory).

C. Energy Consumption and Air Emissions for Existing Sources

1. Energy Consumption

a. *Baseline Energy Consumption.*—EPA's estimated non-water quality environmental impacts for the discharge and zero discharge options, for existing sources, are presented in Table VII–1. EPA set baseline energy consumption according to SBF wells discharging SBF-cuttings at 11 percent retention of base fluid on wet cuttings. Table VII–1 shows, therefore, that the baseline energy consumption (i.e., fuel usage) is zero for existing Gulf of Mexico SBF wells, because increases or decreases in fuel use and air emissions are compared to this level.

TABLE VII–1.—SUMMARY ANNUAL BASELINE, COMPLIANCE, AND INCREMENTAL COMPLIANCE, NON-WATER QUALITY ENVIRONMENTAL IMPACTS OF SBF CUTTINGS MANAGEMENT FROM EXISTING SOURCES

Technology basis	Gulf of Mexico		Offshore California		Cook Inlet, Alaska		Total	
	Air emissions (tons/yr)	Fuel usage (BOE/yr) [a]	Air emissions (tons/yr)	Fuel usage (BOE/yr) [a]	Air emissions (tons/yr)	Fuel usage (BOE/yr) [a]	Air emissions (tons/yr)	Fuel usage (BOE/yr) [a]
Baseline Non-Water Quality Environmental Impacts:								
Currently SBF Discharge (11% reten.)	0	0	NA	NA	NA	NA	0	0
Currently OBF Zero Discharge [b]	47.92	3,433	36.61	2,121	2.08	285	86.61	5,839
Compliance Non-Water Quality Environmental Impacts:								
Discharge Option (7% reten.)	12.54	3,035	0.76	187	0.01	4	13.30	3,226
Zero Discharge Option	338.55	24,125	NA	NA	NA	NA	338.55	24,125
Incremental Non-Water Quality Environmental Impacts Reductions (Increases):								
Discharge Option (7% reten.)	35.38	398	35.86	1,934	2.07	281	73.31	2,613
Zero Discharge Option	(338.55)	(24,125)	0	0	0	0	(338.55)	(24,125)

[a] BOE (barrels of oil equivalent) is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal. diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).
[b] Baseline non-water quality environmental impacts from the 23 (20 percent) OBF wells that convert to SBF upon promulgation of today's proposed rule.

Baseline fuel usage rates for OBF wells in offshore California and coastal Cook Inlet, Alaska derive from activities associated with transporting waste drill cuttings to shore and land-disposing the cuttings. For this analysis, EPA used the method developed to estimate zero discharge impacts under the Offshore and Coastal Oil and Gas Rulemakings. EPA used the volumes of drilling waste requiring onshore disposal to estimate the number of supply boat trips necessary to haul the waste to shore. Projections made regarding boat use included types of boats used for waste transport, the distance traveled by the boats, allowances for maneuvering, idling and loading operations at the drill site, and in-port activities at the dock. EPA estimated fuel required to operate the cranes at the drill site and in-port based on projections of crane usage. EPA determined crane usage by considering the drilling waste volumes to be handled and estimates of crane handling capacity. EPA also used drilling waste volumes to determine the number of truck trips required. The number of truck trips, in conjunction with the distance traveled between the port and the disposal site, enabled an estimate of fuel usage. The use of land-spreading equipment at the disposal site was based on the drilling waste volumes and the projected capacity of the equipment. The annual baseline fuel usage in barrels of oil equivalents (BOE) is 2,121 BOE for offshore California, and 285 BOE for coastal Cook Inlet.

In the Gulf of Mexico analysis, EPA projected that 20 percent of OBF wells in shallow water would become SBF wells as a result of this rule, and therefore they are included in the zero discharge analysis. Baseline fuel usage rates (and all other impacts) for OBF wells in the Gulf of Mexico are based on the assumption that 80 percent of these wells use land-disposal for zero discharge and the remaining 20 percent use on-site injection to dispose of OBF-cuttings. This assumption is discussed further in Section IX of this Preamble, and in the Development Document. Baseline fuel usage rates for zero discharge via land-disposal were calculated using the same analysis used in the offshore rule for California wells and coastal rule for Cook Inlet wells. Baseline fuel usage rates for Gulf of Mexico wells that inject waste cuttings onsite were calculated as the sum of the fuel usage for the model turnkey injection system considered for the zero discharge option, which consists of transfer equipment for moving cuttings, grinding and processing equipment, and injection equipment. The per-well fuel usage rates for wells that use on-site injection are weighted averages of diesel usage rates and natural gas usage rates, according to the estimate that 85 percent use diesel and 15 percent use natural gas as primary power sources in the Gulf of Mexico. By multiplying the average per-well baseline fuel usage rates by the projected annual drilling activity for the four model wells in the Gulf of Mexico, EPA calculated an annual baseline fuel usage of 3,433 BOE for the Gulf of Mexico, and 5,839 BOE for all wells in the baseline.

b. *Compliance Energy Consumption*.—Energy consumption for the discharge option was calculated by identifying the equipment and activities associated with the operation of a vibrating centrifuge to reduce the retention of the synthetic base fluid on drill cuttings from an average 11 percent to seven percent, measured on a wet-weight basis. Details regarding the technology basis for this option are presented in Section VI of this Preamble, and in the Development Document. Using the characteristics of the four model wells (see Section IX.B), EPA calculated per-well energy consumption based on the horsepower demand specified for the vibrating centrifuge by its manufacturer. The horsepower demand was multiplied by the fuel usage rate and the hours of operation required to drill the SBF section of the well, specific to each model well type.

Since they are based on the same technology, the discharge option per-well energy consumption rates are the same for the three geographic areas, but vary based on the fuel source employed in each area. In the Gulf of Mexico, industry sources recently estimated that approximately 85 percent of drilling operations use diesel oil as the primary fuel source, and the remaining 15 percent use natural gas. Information regarding fuel sources for the offshore California area indicates a variety of sources, including diesel, natural gas, and for some platforms, submerged electrical cables connected to shore-based power supplies. For this analysis, it was determined that deep water wells in offshore California use diesel as the primary fuel source, and shallow water wells use natural gas. For coastal Cook Inlet wells, natural gas was determined to be the primary fuel source, based on information supplied by the industry both recently and submitted in the Coastal Oil and Gas Rulemaking effort. Based on these determinations and projected drilling activity estimates, EPA calculated the following annual

discharge option fuel usage rates for the three geographic areas: 3,035 BOE for the Gulf of Mexico, 187 BOE for offshore California, and 4 BOE for Cook Inlet, for a total annual fuel usage rate of 3,226 BOE for existing sources in the discharge option.

EPA calculated energy consumption for compliance with the zero discharge option for the Gulf of Mexico wells that EPA estimates currently discharge SBF cuttings, since these wells would need to convert from discharge to zero discharge under this option. EPA estimated fuel usage rates were estimated by identifying the equipment and activities associated with two zero discharge technologies currently in use in the Gulf of Mexico: 1) transporting waste cuttings to shore-based land disposal sites; and 2) on-site injection. The methods developed for calculating fuel usage for both these zero discharge technologies are described above for baseline OBF wells. While the same line-items were used to estimate impacts for the transport and land-disposal technology scenario in all three geographic areas, the per-well fuel usage rates vary between the three geographic areas due to the various distances traveled by and trip frequencies of boats and trucks in these areas. By multiplying the weighted average per-well fuel usage rates by the projected annual drilling activity for the four model wells in the Gulf of Mexico, EPA calculated a total annual fuel usage rate of 24,125 BOE for existing sources in the zero discharge option.

c. *Incremental Compliance Energy Consumption.* Incremental compliance impacts are the difference between the baseline and the compliance impacts, and indicate the amount by which baseline impacts would be reduced with implementation of the compliance technologies considered. Table VII–1 lists the total annual incremental fuel usage rates for each geographic area for both the discharge and zero discharge options. With the implementation of the discharge option, there would be a reduction in fuel use of 2,613 BOE annually for existing sources. This reduction is due to the elimination of transport and land disposal equipment used to manage waste cuttings from baseline OBF wells that switch to SBFs. Under zero discharge, there would be an increase in fuel use of 24,125 BOE per year for existing sources. This increase is due to the addition of transport and land disposal equipment to manage waste cuttings from baseline SBF wells that currently discharge cuttings.

2. Air Emissions

EPA estimated air emissions resulting from the operation of boats, cranes, trucks, and earth-moving equipment necessary to dispose of waste cuttings onshore, or the operation of on-site grinding and injection equipment, by using emission factors relating the production of air pollutants to time of equipment operation and amount of fuel consumed. The baseline emissions, emissions reductions under the discharge option, and emissions increases under the zero discharge option are presented in Table VII–1.

D. Energy Consumption and Air Emissions for New Sources

Based on current drilling activity data and information provided by industry sources, EPA projects that an estimated 19 new source SBF wells will be drilled annually in the Gulf of Mexico, consisting of 18 deep water development wells and 1 shallow water development well. No new source wells are projected for offshore California and coastal Cook Inlet because of the lack of activity in new lease blocks in these areas. New source wells are defined as those requiring substantial new infrastructure, and exclude exploratory wells by definition (EPA, 1993; EPA, 1996).

Table VII–2 lists the annual energy consumption (i.e., fuel usage) and air emissions calculated for baseline, discharge, and zero discharge option for new sources. The methods used to calculate the per-well impacts for new source wells are the same as for existing sources, described above. The analysis indicates that new source wells in the discharge option will marginally increase fuel use and air emissions above the baseline. This increase is due to implementation of the model SBF recovery device such that, instead of discharging waste SBF-cuttings at the baseline control level of 11 percent retention, would discharge at 7 percent retention. In the zero discharge option, applying zero discharge technologies increases fuel use and air emissions. Both increments represent the use of energy-consuming equipment above the baseline. However, the discharge option raises energy consumption only slightly while the zero discharge option leads to a large increase in energy consumption and corresponding air emissions.

TABLE VII–2.—SUMMARY ANNUAL BASELINE, DISCHARGE, AND ZERO DISCHARGE NON-WATER QUALITY ENVIRONMENTAL IMPACTS OF SBF CUTTINGS MANAGEMENT FROM NEW SOURCES

Technology basis	Gulf of Mexico	
	Air emissions (tons/yr)	Fuel usage (BOE/yr) [a]
Baseline: Discharge (11% retention)	0	0
Compliance:		
Discharge (7% retention)	1.28	311
Zero Discharge	39	2,932
Incremental Reductions (Increases):		
Discharge (7% retention)	(1.28)	(311)
Zero Discharge	(39)	(2,932)

[a] BOE (barrels of oil equivalent) is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).

E. Solid Waste Generation and Management

The regulatory options considered for this rule will not cause generation of additional solids as a result of the treatment technology. However, the quantity of SBF-cuttings discharged under the discharge option will be traded for a nearly equal quantity of OBF-cuttings disposed of onshore or injected onsite to comply with the zero discharge option. Implementation of the discharge option will result in reductions of solid waste currently disposed at land-based facilities and by injection, due to the OBF wells converting to SBF wells. For existing sources currently using OBFs, under the discharge option, the annual amount of waste cuttings disposed at land-based facilities would be reduced by 30 MM pounds, and the amount injected would be reduced by 4 MM pounds, for a total of 34 MM pounds. Implementation of the zero discharge option by existing sources would result in an increase of 132 MM pounds of waste cuttings disposed onshore, and 33 MM pounds injected, for a total of 165 MM pounds. Thus, under the discharge option, for existing sources the total reductions in amount of waste cuttings disposed of at land-based facilities would be 162 MM pounds, and the total amount injected would be reduced by 37 MM pounds.

The new sources analysis considers only SBF wells that discharge waste cuttings with 11 percent retention of synthetic base fluid on cuttings, which under the discharge option would discharge at 7 percent. Therefore, under the discharge option the incremental amount of waste cuttings disposed onshore or injected is zero. Under the

zero discharge option, EPA estimated that 10 MM pounds would be transported to shore and 2.6 MM pounds would be injected, for a total of 13 MM pounds disposed annually for new sources.

Combining the reductions from the discharge option with the increases in the zero discharge option, for existing and new sources combined, shows that the total effect of discharge versus zero discharge reduces the amount of OBF-cuttings sent to shore for land disposal by 172 MM pounds annually and reduces the amount injected by 40 MM pounds annually. Thus the total reduction in zero-discharge OBF-cuttings waste is 212 MM pounds annually.

F. Consumptive Water Use

Since little or no additional water is required above that of usual consumption, no consumptive water loss is expected as a result of this rule.

G. Safety

EPA investigated the possibility of an increase in injuries and fatalities that would occur as a result of hauling additional volumes of drilling wastes to shore under the zero discharge option. EPA acknowledges that safety concerns always exist at oil and gas facilities, regardless of whether pollution control is required. EPA believes that the appropriate response to these concerns is adequate worker safety training and procedures as is practiced as part of the normal and proper operation of oil and gas facilities.

EPA believes the preferred discharge option may marginally decrease the number of accidents due to the decrease in supply vessel traffic, as well as the decrease of crane usage to load and unload cuttings boxes. However, EPA finds that these differences are not significant, in light of the analysis of the following section on vessel traffic.

H. Increased Vessel Traffic

EPA estimated the amount of additional vessel traffic that would result from the implementation of the preferred discharge option and the zero discharge option. To measure increases or decreases in vessel traffic, the current baseline level of supply boat frequency for wells currently drilled with OBF was calculated using the numbers of boat trips estimated as part of the energy consumption and air emissions impact analyses described above.

To comply with the zero discharge option, EPA estimates that the 113 existing and new source wells in the Gulf of Mexico (GOM) currently drilled with SBF would implement zero discharge technologies. Based on the assumption that 80 percent of these wells would transport waste drill cuttings to shore, an estimated total of 91 boat trips per year would be required. No additional boat trips would be required in California and Cook Inlet, Alaska, because these regions are currently at zero discharge of SBF-cuttings.

Under the discharge option, 23 (20 percent) GOM wells, the 12 California wells, and the one Cook Inlet well, currently drilled with OBF would convert to SBF usage, thereby eliminating the need for hauling OBF cuttings to shore. Baseline supply boat trips per year were estimated as follows: 18 trips for the 23 wells in the Gulf of Mexico where 18 wells transport drill cuttings to shore and the other 5 inject on-site; 12 trips for the 12 wells in offshore California; and 1 trip for the well in coastal Cook Inlet. Therefore, EPA projects that supply boat traffic would decrease by 31 boat trips per year. Compared to the zero discharge option which led to 91 additional boat trips per year in the GOM, the discharge option reduces boat traffic over the three regions by 122 boat trips per year, and in the GOM by 109 boat trips per year. As cited in the Offshore Oil and Gas Development Document, 10 percent of the total Gulf of Mexico commercial vessel traffic, or approximately 25,000 vessels, service oil and gas operations. Therefore, compared to the zero discharge option, the discharge option decreases commercial boat traffic by 0.04 percent in the GOM. EPA does not consider this decrease a significant impact.

VIII. Water Quality Impacts of Proposed Regulations

A. Introduction

EPA has evaluated the potential effects of the proposed regulation on the receiving water environment. Consistent with the scope of the rule, the analysis covers only those geographic areas where water-based drilling fluids (WBFs) may be discharged under current regulations, i.e., offshore waters beyond three miles from the shoreline, Alaska offshore waters with no three-mile restriction, and the coastal waters of Cook Inlet, Alaska.

Based on performance characteristics, SBFs are considered to be a substitute for traditional oil-based drilling fluids (OBFs) using diesel oil and mineral oil, but not for WBFs. For the water quality impacts analysis, EPA has assumed that the future use of WBFs will be in keeping with current practice, and that SBFs will replace traditional OBFs at 20 percent of the wells where OBFs would otherwise be used. EPA intends that ''whole'' SBFs will not be discharged, and therefore only the drill cuttings and the adherent residual fluid will be discharged. This is in contrast with the current regulation for WBF drilling wastes, which allows for the controlled discharge of both cuttings and whole fluids. Discharge of traditional OBF drilling wastes to water is not allowed by current regulations and permits. OBF drilling wastes are therefore injected into disposal wells or shipped to shore for proper disposal.

Allowing the discharge of SBF-cuttings would make them, in many cases, less expensive to use than OBFs, and thus would encourage the use of SBFs. Changing practices from traditional OBF drilling/offsite disposal to SBF drilling/onsite discharge is expected to produce significant non-water quality environmental benefits (see Section VII). However, since discharge of traditional OBFs is prohibited, switching from OBF drilling/offsite disposal to SBF drilling/onsite discharge would result in additional water quality impacts. Where SBF cuttings are currently being discharged, the proposed discharge controls would reduce the water quality impacts. EPA has evaluated the water quality impacts of SBF discharges, and has used this analysis in balancing today's proposal with non-water quality environmental impacts associated with the use of OBFs. Based on this analysis, EPA prefers to allow the controlled discharge of SBF cuttings and reduce non-water quality environmental impacts.

The chemical composition (and for the most part, toxicity testing) of various existing SBFs indicate that they are considerably less toxic and less hazardous to human health than traditional OBFs. Therefore, the water quality impacts from an accidental spill of SBFs would be expected to be lower compared to a similar spill involving traditional OBFs.

B. Types of Impacts

1. Pollutant Characterization

Although SBFs are not considered to be a replacement for WBFs, it is useful to compare the two types of fluids, since the discharge of WBFs is currently allowed. As with WBF discharges, SBF-cuttings discharges will contain total suspended solids (TSS) associated with the drill cuttings and solids of the drilling fluid, metals associated with the drilling fluid barite and the geologic formation, and priority and nonconventional pollutants associated

with potential contamination by formation (crude) oil. Some pollutants of concern from the barite include priority metals such as arsenic, chromium, copper, lead, mercury, nickel, and zinc, and nonconventional pollutants such as aluminum and tin. Formation oil contamination may include priority organics such as fluorene, naphthalene, phenanthrene, and phenol, and nonconventional pollutants such as alkylated benzenes and total biphenyls.

Compared to WBFs and associated cuttings, SBF-cuttings will have additional pollutants associated with the synthetic base fluids themselves. In general, these pollutants are long-chain hydrocarbons or esters of vegetable fatty acids which present a significant organic loading. They are considered non-conventional pollutants.

The principal water column impacts anticipated from SBF drilling wastes are increased turbidity and toxicity. Turbidity is associated with the discharged solids, and can negatively impact fish and biotic productivity. Toxicity may arise from the waste stream pollutants that leach into the water column. Previous modeling of offshore WBF discharges indicates that these effects are localized and short-term (on the order of hours). The additional organic pollutants comprising the SBFs are not expected to exacerbate water column impacts, since they generally are water non-dispersible and exhibit very low solubility in water.

Laboratory and field studies indicate that the primary impacts from SBF-cuttings discharges are associated with the benthic community. These impacts include those associated with the discharge of WBFs, i.e., smothering of sessile organisms, toxicity, and altered sediment grain size, leading to reductions in abundance and diversity of the benthic biota over a localized area. SBF-cuttings are expected to produce additional impacts associated with the base fluid pollutants, such as organic enrichment, anoxia resulting from biodegradation, and potential increased toxicity. In nutrient-poor deep sea environments, organic enrichment may alter the benthic community by increasing overall biomass density.

Toxicity potential of SBFs seems better assessed through sediment-phase tests than aqueous-phase tests, since SBFs are hydrophobic and have strong self-adherence properties. Based on the chemical composition of SBFs and on limited sediment-phase test data (five sets of test data by different scientists using various sediment-dwelling and water column-dwelling marine organisms), the potential for toxicity varies among fluid types, but generally appears to be low. However, some test results indicate that sediment toxicity of certain SBFs is not reduced compared to OBFs.

Biodegradability is an important SBF parameter, since organic enrichment and ensuing sediment oxygen depletion is expected to be a dominant impact of SBF discharges. All SBFs have high theoretical oxygen demands and are likely to produce a substantial sediment oxygen demand as they degrade in the receiving environment.

The available information on the bioaccumulation potential of SBFs is limited, consisting of six studies on octanol:water partition coefficients (P_{ow}) and two studies on tissue uptake in experimental exposures. The limited data and the chemical composition of SBFs suggest that existing SBFs do not pose a significant bioaccumulation potential.

EPA intends to generate or obtain additional data regarding the potential for toxicity, bioaccumulation, and persistence of SBFs, through laboratory studies and seabed surveys at SBF-cuttings discharge sites. The further work EPA intends to perform on laboratory testing is detailed in Section VI of today's notice. Further intended seabed surveys are discussed at the end of this section under the heading ''Future Seabed Surveys.''

2. Seabed Surveys

Past seabed surveys provide some insight into the fate and effects of SBF discharges. Results of several seabed surveys are described below.

a. *EPA/Industry Seabed Survey.*—In August 1997, EPA and industry jointly conducted a seabed survey in the Gulf of Mexico at three platforms on the central Louisiana continental shelf where SBF-cuttings were discharged. The purpose of the survey was to conduct a preliminary evaluation to determine the areal extent of observable impact. At the Grand Isle site (water depth = 61 meters), 1,315 bbl (167 metric tons) of internal olefin (IO) SBF were discharged on cuttings. Discharge ceased 25 months prior to the survey. At the South Marshall Island site (water depth = 39 meters), 94 bbl (12 metric tons) of linear alpha olefin (LAO) and IO SBF were discharged on cuttings. Discharge ceased 11 months prior to the survey. At the South Timbalier site (water depth = 33 meters), 2,390 bbl (304 metric tons) of IO SBF were discharged on cuttings. Discharge ceased 10 months prior to the survey.

Sediment was sampled at stations from 50 to 150 meters away from the platforms, with reference stations at 2,000 meters. Samples were collected at each station for physical and chemical analysis. Samples for biological analysis and toxicity testing were collected at selected stations. The odor of hydrogen sulfide was observed in seven of the 61 samples collected near the platforms (within 150 meters), indicating anoxic conditions. Although only a small fraction of the available seabed area was sampled, the results indicate that detectable SBF hydrocarbon (SBF-H.C.) concentrations were limited to within 50 to 150 meters of the platforms, with the highest concentrations (on the order of 10,000 ppm) being within 50 meters of the platforms. Elevated SBF-H.C. concentrations appeared to occur in a spotty, mosaic pattern rather than in a continuous unbroken pattern around the platform.

Ten-day acute sediment toxicity tests were performed by the industry coalition on six samples near the platforms. The tests were performed using the amphipods *Leptocheirus plumulosus* and *Ampelisca abdita.* With the exception of one sample, survivals of both organisms exceeded 75 percent (survival of *A. abdita* was 62 percent in a sample taken 100 meters from the Grand Isle platform). For all platforms, *L. plumulosus* survivals were greater than those observed for the control sediment (although control survival was extremely low). Average survivals over all non-reference, non-control sediments were 92 percent and 83 percent for *L. plumulosus* and *A. abdita,* respectively. Average reference station sample survivals were 95 percent and 91 percent for *L. plumulosus* and *A. abdita,* respectively. Average control sample survivals were 65 percent and 83 percent for *L. plumulosus* and *A. abdita,* respectively.

EPA also conducted sediment toxicity tests on the seabed survey samples. Sample locations include the same ones as those tested by the industry coalition, plus three additional locations around the Grand Isle platform. For all platforms, survival of *A. abdita* indicated no adverse toxicity beyond that demonstrated for the control sediment. *L. plumulosus* test results demonstrated a high degree of toxicity (0—65 percent survival) within 150 meters of the Grand Isle platform, with the higher toxicities at locations closer to the platform. Compared to the Grand Isle site, *L. plumulosus* test results indicated much lower toxicity near the South Marshall Island platform (83–92 percent survival) and the South Timbalier platform (83–85 percent survival). Average survival over all non-reference, non-control sediments were 60 percent and 85 percent for *L. plumulosus* and *A. abdita,* respectively.

Average reference station sample survivals were 88 percent and 87 percent for *L. plumulosus* and *A. abdita,* respectively. Average control sample survivals were 95 percent and 87 percent for *L. plumulosus* and *A. abdita,* respectively.

EPA also collected samples at the Grand Isle and South Marshall Island sites for macroinfaunal analysis, but the samples have not yet been analyzed.

b. *Other Seabed Surveys.*—There are limited biological assessment data from seabed surveys around platforms where SBF-cuttings have been discharged. Of the fourteen other sites where seabed surveys have been performed, only five include biological analyses. Two of the sites are in the Gulf of Mexico; the other three are in the North Sea.

One Gulf of Mexico study (1995) was performed at a platform in 39-meter deep water where 354 bbl (45 metric tons) of a poly alpha olefin (PAO) SBF was discharged on cuttings. Surveys were conducted nine days, eight months, and two years after discharge ceased. Sediment was sampled at stations from 25 to 200 meters away from the platform, with reference stations at 2,000 meters. Eight months after discharge, the total petroleum hydrocarbon (TPH) concentration in the sediment decreased substantially (60 percent–98 percent) at all but the closest, 25-meter stations. It is uncertain how much of this decrease is attributable to biodegradation, as opposed to sediment redistribution and reworking. It appears that little further reductions in TPH sediment concentration occurred between the 8th-month post-discharge survey and the second-year post-discharge survey. Limited analysis of the benthic fauna (performed in the second-year post-discharge survey only) indicate significant differences (reduced abundance and richness) at the 25-meter and 50-meter stations compared to reference stations.

Another Gulf of Mexico study (1998) was performed in a relatively deep water environment in the northern Gulf, at a platform in 565-meter deep water. Approximately 5,500 bbls (699 metric tons) of an SBF, using a blend of 90 percent linear alpha olefin and 10 percent vegetable ester as the base fluid, had been discharged on cuttings prior to the first survey, which was conducted approximately four months after discharge ceased. A second survey was performed approximately eight months after the first survey (approximately one year after the first series of discharges ceased). An additional 1,600 bbls (203 metric tons) of SBF were discharged on cuttings two days prior to the second survey.

Sediment was sampled out to 90 meters from the platform. High sediment SBF concentrations (up to 198,000 ppm) suggest that the in-situ biodegradation rate was lower than anticipated. Between the two surveys, densities of polychaetes and nematodes increased significantly, and the dominant taxon shifted from cyclopoid copepods to polychaetes and nematodes. Biomass density was highest in the area where the highest SBF concentrations were found. In the second survey, the densities of polychaetes, cyclopoid copepods, and gastropods in this area were approximately 40, 650, and 3,000 times higher than background levels for northern Gulf of Mexico reference sites at similar water depths. Fish densities in the vicinity of the platform were approximately 3–10 times higher than background levels. The analysis indicates that the SBF may be acting as a nutrient source and thereby supporting increased biomass in a typically nutrient-poor deep sea benthic environment.

One of the North Sea studies (1996) includes an impact study of the discharge of 180 metric tons of an ester SBF at a Dutch well site in 30-meter deep water. Surveys occurred one, four, and eleven months after discharge ceased. In each survey, the SBF was detected in the upper 10 cm of sediment out to a distance of 200 meters from the discharge site (the farthest distance sampled for sediment ester concentration). During the 4th-month post-discharge survey, sediment ester levels appeared to increase, apparently due to resuspension and transport of contaminated sediment. Significant decreases of 65 percent to 99 percent in sediment ester levels occurred between the 4th-month and 11th-month post-discharge surveys. Effects on benthos abundance and richness were more extensive; in the 4th-month post-discharge survey, effects were noted at 500-meter stations (the farthest distance sampled for biological assessment), with ''pronounced'' effects within 200 meters. Benthic analyses from the 11th-month post-discharge survey indicated significant effects only out to 200 meters. Additionally, recolonization and recovery were noted within the study area after 11 months.

Another North Sea study (1991) involved the discharge of 97 metric tons of an ester SBF at a Norwegian well site in 67-meter deep water. Surveys were conducted immediately, one year, and two years after discharge ceased. Samples were taken out to 1,000 meters from the platform. Sediment ester levels fell dramatically between sampling events, with both maximum and average values within 1,000 meters decreasing more than three orders of magnitude between the time-zero and first-year post-discharge surveys, and more than five orders of magnitude between the time-zero and second-year post discharge surveys. Benthic organism abundance and richness were severely impacted out to 100 meters in the first survey (immediately post-discharge). Evidence of minor macrobenthic community changes was seen in the second-year post-discharge survey.

Another North Sea study (1992) examined the effects of the discharge of 160 metric tons of an ether SBF at a Norwegian well site. Surveys were conducted immediately, one year, and two years after discharge ceased. Sediment samples were taken out to 200 meters from the platform. Ether levels appeared to fall continuously, with mean ether levels decreasing by factors of two-fold between the time-zero and first-year post-discharge surveys, and ten-fold between the time-zero and second-year post-discharge surveys. This degree of degradation appears to be considerably less than that noted for the ester SBF site noted above. The author interpreted this as indicating that a lag phase occurred in the biodegradation of the ether SBF. (Laboratory biodegradation testing using the solid phase test also shows that ethers have a much slower degradation rate than vegetable esters.) Benthos were analyzed at only four stations in the second-year post-discharge survey; the author reported that the observed effects were ''remarkably weak''.

c. *Conclusions.*—There is limited field information upon which to base broad conclusions about the potential extent of biological impacts from SBF discharges. Based on seabed surveys, it appears that significant biological impact zones may range from as little as 50 meters to as much as 500 meters from the platform initially, to as much as 200 meters a year later. Generally, severe initial effects seem likely within 200 meters of the discharge. The initiation of benthic recovery seems likely within a year after discharge has ceased, and it seems unlikely that recovery will be complete within two years (to date, no post-discharge surveys have been performed beyond a two-year period). The time scale of complete recovery from SBF discharges (and oil and gas drilling and production platform activity in general) is uncertain. Impact zones and recovery rates will be site-specific, depending on factors such as water depth, current, temperature, and

seafloor energy, all of which affect the rate of degradation and dispersion of the SBF components and drill cuttings. In nutrient-poor benthic environments such as the deep sea, SBFs may serve as a nutrient source and thereby increase overall biomass density.

C. Water Quality Modeling

To assess the water quality impacts of the regulatory options, EPA modeled incremental pollutant concentrations, in the water column and in the sediment pore water, at the edge of the 100-meter radius mixing zone established for offshore discharges by CWA Section 403, Ocean Discharge Criteria, as codified at 40 CFR Part 125 Subpart M. The modeling was performed for the Gulf of Mexico, Offshore California, and Cook Inlet, Alaska discharge regions. The modeling was performed for each model well (shallow water exploratory, shallow water development, deep water exploratory, and deep water development), as appropriate for each discharge region, for current industry practice and each of the two options:

(1) Current Practice = 11 percent base fluid retention on cuttings (by weight on wet cuttings) with 0.2 percent crude contamination (by volume in drilling fluid) .

(2) Discharge Option = seven percent retention on cuttings with 0.2 percent crude contamination.

(3) Zero Discharge.

The seven percent retention above is based on the long-term average with the control technology of today's proposal, as detailed in Section VI of today's notice. The 0.2 percent crude contamination is not based on the regulatory limit but rather a concentration EPA estimates would commonly be found in SBF discharged with cuttings.

EPA compared the modeled values to federal water quality criteria/toxic benchmark recommendations for marine acute effects, marine chronic effects, and human health effects via ingestion of organisms. For the most part, individual modeled pollutant concentrations were compared to the criteria for each pollutant. In the pore (interstitial) water analysis, potential additive toxic effects of six of the metals (cadmium, copper, lead, nickel, silver, and zinc) were accounted for by converting the pore water concentrations to toxic units and summing them. This approach is in accordance with EPA's proposed sediment guidelines for these metals, which indicate that benthic organisms should be acceptably protected if the sum of the Interstitial Water Guidelines Toxic Units (IWGTUs) for these six metals is less than or equal to one. (Alternatively, the benthic organisms should be acceptably protected if the sum of the molar concentrations of simultaneously extracted metals (SEM) for these six metals is less than or equal to the molar concentration of acid volatile sulfide (AVS) from the sediment.) The pollutant-specific IWGTU is defined as the dissolved interstitial water concentration of the pollutant divided by the water quality criterion (chronic value) for that pollutant.

EPA criteria/toxic benchmark recommendations are considered by the States in developing water quality criteria for State waters. The criteria are not steadfast standards in federal offshore waters, but EPA takes them into account in making a determination of whether a discharge will cause unreasonable degradation of the marine environment (See 40 CFR Part 125.122(a)(10)). The modeled pollutants include only those priority and nonconventional pollutants for which EPA has established numeric marine water quality criteria. Concentrations of TSS, synthetic base fluids, and some other constituents have therefore not been modeled. However, EPA emphasizes that much of the anticipated benefits of controlling SBF discharges lies in reducing discharge quantities of TSS and oil and grease (including synthetic base fluids). For example, based on model well scenarios, EPA projects that the controlled discharge option will reduce discharges of total oil and SBF-associated TSS (i.e., TSS associated with SBFs adhering to cuttings) by 43 percent compared to current industry practice where SBFs are currently being discharged. Reducing the discharge quantities of these pollutants at existing SBF discharge sites is expected to decrease the potential impact on the environment (particularly the benthos) by reducing the severity of physical habitat alteration, anoxia, and potential toxicity and bioaccumulation. Where operators switch from OBF drilling/offsite disposal to SBF drilling/onsite discharge, total pollutant loading to the aquatic environment will increase.

EPA recognizes some limitations in this analysis. Due to a lack of adequate modeling tools, the analysis does not quantify the effects of smothering, physical habitat alteration, or anoxia. Additionally, the analysis does not consider background pollutant concentrations or pollutant loadings from other potential discharges, such as WBFs or produced water. The analysis is conservative in that the pollutants are assumed to be fully leached (to the extent that they are leachable in accordance with their partitioning coefficients and leach percentages) into the medium under consideration. That is, for the water column analysis, EPA assumed that all leachable pollutant mass leaches into the water column (with none left over for leaching into the pore water). Likewise, for the pore water analysis, EPA assumed that all of the leachable pollutant mass leaches into the pore water (without any mass lost to the water column).

The modeled water column concentrations are based on existing Offshore Operators Committee modeling of OBF-cuttings discharges, since dispersion behavior of SBF cuttings is expected to be similar to that of OBF-cuttings. EPA used median estimated dilution values (specific to each discharge region) at the 100-meter mixing zone to calculate predicted water column concentrations for pollutant discharges from the model wells. Non-synthetic organic pollutants were assumed to be fully dissolved in the water column. Effluent metal concentrations were adjusted by pollutant-specific mean seawater leach percentage factors to determine water column concentrations. The modeling indicates that neither current industry practice nor the discharge option would result in exceedances of any federal water quality criteria/toxic benchmarks at the edge of the 100-meter mixing zone, for any of the modeled discharge regions.

The modeled sediment pore water concentrations for the Gulf of Mexico are based on sediment pollutant characterizations from five field surveys of 11 wells (ten in the North Sea, one in the Gulf of Mexico) where SBFs have been discharged. The California and Cook Inlet analyses are also based on this approach, but data from two shallow wells were eliminated to better represent discharge conditions in those regions. Sediment synthetic concentrations at 100 meters from the discharge point were taken or interpolated from each of the surveys. An average sediment synthetic concentration was derived for each model well, and the sediment concentration of each pollutant was calculated based on the ratio of each pollutant to the synthetic material. Pore water pollutant concentrations were then calculated based on mean seawater leach percentages (for metals) and partition coefficients (for organics). Organic pollutant partitioning was based on an average fractional organic carbon content for sediment in each discharge region.

Table VIII–1 lists the factors by which projected pore water concentrations of certain pollutants would exceed federal water quality criteria/toxic benchmarks for each regulatory scenario and model well in the modeled discharge regions. EPA notes that these pollutants are associated with the geologic formation and/or the barite used in all drilling fluids, and are not specific to SBF discharges. Modeling of current industry practice (with respect to SBF discharges only) indicates that the pore water pollutant concentrations would exceed some federal criteria/toxic benchmarks at the edge of the 100-meter mixing zone in several model well scenarios. The modeling indicates that, due to discharge limits on drilling fluid retention, the discharge option would reduce pollutant pore water concentrations by 43 percent compared to current industry practice (where SBFs are currently being discharged). The discharge option would thereby reduce the number and magnitude of projected exceedances compared to current industry practice (at existing SBF discharge sites). Zero discharge would obviously eliminate any projected exceedances.

TABLE VIII–1.—FACTORS BY WHICH PORE WATER POLLUTANT CONCENTRATIONS AT THE EDGE OF THE 100-METER MIXING ZONE WOULD EXCEED FEDERAL WATER QUALITY CRITERIA RECOMMENDATIONS FOR EACH REGULATORY OPTION AND MODEL WELL [a]

Discharge region	Pollutant	Shallow water				Deep water			
		Development well		Exploratory well		Development well		Exploratory well	
		Current practice	Discharge option	Current practice	Discharge option	Current practice	Discharge option	Current practice	Discharge option
Gulf of Mexico	Arsenic	1.3	[c]	2.7	.....	1.9	1.1	4.3	2.5
	Chromium	.....	.....	1.7	.....	1.3	.....	2.8	1.6
	Mercury	.....	.....	.....	.....	.....	.....	1.2	.....
	Metals Composite([b]).	1.1	.....	2.3	1.3	1.7	.....	3.7	2.1
California	Arsenic	.....	.....	Not applicable		1.2	.....	Not applicable	
	Metals Composite([b]).	.....	.....	Not applicable		1.1	.....	Not applicable	
Cook Inlet, Alaska.	Arsenic	.....	.....	Not applicable		Not applicable		Not applicable	
	Metals Composite([b]).	.....	.....	Not applicable		Not applicable		Not applicable	

[a] There would be no exceedances for any pollutants with the zero discharge option.
[b] Metals composite includes cadmium, copper, lead, nickel, silver, and zinc.
[c] Blanks indicate no exceedances are predicted.

D. Human Health Effects Modeling

EPA has also evaluated the effects of the current industry practice and regulatory options on human health via consumption of finfish and shrimp from affected fisheries. Pollutant concentrations in finfish tissue (applicable to the Gulf of Mexico, offshore California, and Cook Inlet discharge regions) and shrimp tissue (applicable to the Gulf of Mexico and offshore California) were estimated based on the previously described water quality modeling techniques. As with the water column and pore water analyses, EPA considered only incremental loadings from SBF discharges, irrespective of other discharges and background concentrations. The analysis is based on water-only exposure of organisms (i.e., it does not consider organism exposure through the food web), and includes only those pollutants for which a bioconcentration factor has been established. Thus, the analysis does not project uptake of synthetic compounds or nonconventional pollutants.

In assessing human health impacts, EPA considered a seafood intake rate of 177 grams per day. This value represents the 99th percentile of daily seafood intake (fresh/estuarine and marine, uncooked basis), based on the Combined USDA 1989, 1990, and 1991 Continuing Survey of Food Intakes by Individuals. This intake rate is reflective of high-end consumers in the general population, and is also a reasonable default value for subsistence fishers. For the shrimp analysis, the intake rate was adjusted by the estimated percent of shrimp catch affected by SBF-cuttings discharges. The finfish intake rate was not adjusted, due to lack of data on affected finfish landings. The finfish intake rate is therefore much more conservative than the shrimp intake rate, as all consumed fish are assumed to be affected by SBF-cuttings discharges.

To estimate potential non-cancer (toxic) effects, EPA calculated the Hazard Quotient for each pollutant. The Hazard Quotient is the estimated pollutant intake rate divided by the pollutant-specific oral reference dose, which represents a level that is protective of human health with respect to toxic effects. A Hazard Quotient greater than one indicates that toxic effects may occur in exposed populations. For arsenic (a human carcinogen), EPA also estimated the lifetime marginal risk of developing cancer, using the EPA-developed, pollutant-specific potency slope factor. For purposes of this analysis, a risk level of 1×10^{-6} is considered to be acceptable.

The finfish exposure assessment is based on incremental pollutant exposures within 100 meters of each platform. The spatial extent of exposure within this area was derived using average dilution values (specific to each discharge region) within the mixing zone, based on existing Offshore Operators Committee modeling of OBF-cuttings discharges. Water column pollutant concentrations were projected using leach percentages and partitioning coefficients, and finfish uptake was calculated based on pollutant-specific bioconcentration factors and a catch-weighted average lipid content of 2.14 percent.

The modeling indicates that, due to discharge limits on drilling fluid retention, the discharge option would reduce pollutant tissue concentrations in finfish by 43 percent compared to current industry practice (where SBFs

are currently being discharged). Neither current industry practice nor the discharge option would result in toxic human health impacts or excess cancer risk under a 99th percentile consumption scenario, for any of the modeled discharge regions.

For the shrimp exposure assessment in the Gulf of Mexico and offshore California, EPA estimated an impact area based on field survey data and an assumed threshold concentration of 100 ppm for synthetic fluid in sediment. Sediment pollutant concentrations for each model well were calculated based on one year's worth of cuttings discharges, assuming an affected depth of 5 cm and uniform distribution of cuttings over the impact area. Pore water pollutant concentrations were projected using leach percentages and partitioning coefficients, and shrimp uptake was then calculated based on pollutant-specific bioconcentration factors and a shrimp lipid content of 1.1 percent.

The modeling indicates that, due to discharge limits on drilling fluid retention, the discharge option would reduce pollutant tissue concentrations in shrimp by 43 percent compared to current industry practice (where SBFs are currently being discharged). Neither current industry practice nor the discharge option would result in toxic human health impacts or excess cancer risk under a 99th percentile consumption scenario, for either of the modeled discharge regions.

E. Future Seabed Surveys

1. Ocean Discharge Criteria

Permits authorizing the discharge of SBF-cuttings are required to (a) meet technology-based requirements to set the control floor, and (b) meet section 403(c) of the Clean Water Act (CWA) Ocean Discharge Criteria, or, in state waters of Cook Inlet, Alaska, meet state water quality criteria. Today's notice proposes the technology-based discharge controls. While not a part of today's proposed rule, the following briefly describes the CWA 403(c) requirements and the future seabed surveys EPA thinks should occur, based on currently available information, to satisfy these permit requirements. The seabed surveys that industry has planned to conduct are also presented.

The nature, extent and duration of seabed surveys required by discharge permits may increase or decrease as further information is gathered, and any monitoring requirement shall be decided by the EPA or delegated state permitting authority. A decision that sufficient seabed survey information has been gathered in one region does not constitute grounds that further seabed surveys are no longer required in other regions.

For ocean discharges, the ambient environmental effect information needed to satisfy EPA permit requirements is specified in Clean Water Act section 403(c), Ocean Discharge Criteria, as codified at 40 CFR Part 125, subpart M. This subpart establishes guidelines for issuance of National Pollutant Discharge Elimination System (NPDES) permits for the discharge of pollutants from a point source into the territorial seas, the contiguous zone, and the oceans. These criteria require that a determination be made whether a discharge will cause unreasonable degradation to the marine environment based on several considerations, including the quantities, composition and potential for bioaccumulation or persistence of the pollutants to be discharged, and considerations relating to the importance and vulnerability of the potentially exposed biological communities and human health (see 40 CFR Part 125.122).

If there is insufficient information to determine prior to issuing the permit that there will be no unreasonable degradation to the marine environment, the Ocean Discharge Criteria require that a monitoring program be specified. This monitoring program must be sufficient to assess the impact of the discharge on water, sediment, and biological quality including, where appropriate, analysis of bioaccumulative and/or persistent impact on aquatic life (see § 125.123 (d) (2)). According to § 125.123 (c) (1) the discharge may not cause irreparable harm to the marine environment during the period in which monitoring is undertaken. If data gathered through monitoring indicate that continued discharge may cause unreasonable degradation, the discharge must be halted or additional permit limitations established.

2. EPA Suggestions for Monitoring Seabed Effects

EPA thinks that currently there is insufficient information to determine that there will be no unreasonable degradation to the marine environment. The Ocean Discharge Criteria, therefore, require that a monitoring program be specified in permits allowing the discharge of SBF-cuttings. The ambient environmental studies should monitor the rate of seabed recovery around several offshore and coastal platforms where SBF-cuttings have been discharged. Sites should be selected to include both deep water and shallow water locations, and should investigate the different types SBFs, according to base fluid, which the permits may allow.

A detailed study may investigate baseline contaminants and benthic invertebrate analysis, disappearance of SBF base materials over time, toxicity of sediment over time, and rate of recolonization by benthic organisms. Desired endpoints include impacts to benthos, sediment characterization, and contribution to hypoxia.

To characterize the seabed survey site, detailed discharge information should be gathered on the platform level. This information should include the dates, prevailing current during discharge, and amounts, for all discharges: WBF, WBF-cuttings, and SBF-cuttings. The WBF and SBF formulations should also be provided. As a detail to the SBF-cuttings discharge quantities, the determination of quantity of synthetic material discharged should also be provided.

3. Industry's Plans for Seabed Surveys

EPA understands that the industry is planning a cooperative effort to address the CWA 403(c) requirements in the GOM. Industry representatives have told EPA that their cooperative seafloor study would include a review of historical data on SBF usage on the shelf and slope, and these data would be analyzed to select a representative series of platforms. The cooperative effort plans that three cruises would be conducted to evaluate equipment and sampling strategies, delineate cuttings deposition profiles (areal extent as well as thickness profile), determine SBF concentrations with depth and distance from source, and to determine if zone of biological influence can be determined. It is anticipated that most of the study sites (e.g., 6–12) locations would be on the shelf, and one or two would be located in deepwater. However, EPA may recommend that more deepwater surveys be conducted, in proportion to the total number of SBF wells drilled in the deepwater versus the shallow water. Parameters to be considered in platform selection included type and volume of synthetics released, number of wells drilled, water depth, shunt depth, and length of time since last discharge. The cooperative effort plans that a combination of side scan sonar, via remotely operated vehicle cameras, and physical grab sampling would be used to determine cuttings deposition. Mineralogy and sediment chemistry are planned to verify cuttings and SBF presence. Oxygen measurements and relative percent difference layer determinations are planned to evaluate SBF-induced anoxia. Biological sampling would be conducted at

selected sites to evaluate ability to measure community structure changes relative to drilling discharges. The deepwater location(s) (between 500–1,200 m) would be sampled and surveyed by the remotely operated vehicle to assess deepwater deposition and effects.

IX. Cost and Pollutant Reductions Achieved by Regulatory Alternatives

A. Introduction

This section presents EPA's methodology and results for estimating the compliance costs and pollutant reductions for the discharge and zero discharge options. EPA calculated costs and loadings on a model well basis, and determined total costs and loadings by multiplying the model well values by the number of wells. Since this is a differential analysis, the only wells, pollutants, and costs considered are those that are expected to change as a result of this proposed rule were it to become a final rule. Therefore, wells currently drilled with SBF are considered in the analysis, and also OBF wells that EPA anticipates will convert to SBF upon completion of this rule. However, wells currently using OBF and not converting to SBF would not incur costs or realize savings in the analysis. EPA assumed that only those wells using SBF or OBF currently would potentially use SBF in the future, and so wells drilled exclusively with WBF are not treated as incurring any costs or realizing any cost savings in this analysis. Also, of the wells that are in the analysis because they use SBFs or OBFs, the upper sections of the well that are drilled with WBF are not associated with any costs or savings in the analysis.

B. Model Wells and Well Counts

EPA developed model well characteristics from information provided by the American Petroleum Institute (API) to estimate costs to comply with, and pollutant reductions resulting from, the proposed discharge option and the zero-discharge option. API provided well size data for four types of wells currently drilled in the Gulf of Mexico (GOM); development and exploratory in both deep water (i.e., greater or equal to than 1,000 feet) and shallow water (i.e., less than 1,000 feet). The following text refers to these wells by the acronyms DWD (deep-water development), DWE (deep-water exploratory), SWD (shallow-water development), and SWE (shallow-water exploratory).

The model well information from API provided length of hole drilled for successive hole diameters, or intervals. From this, EPA calculated the hole volume for the well intervals that reportedly used SBF or OBF. For the four model wells and assuming 7.5 percent washout of the hole, EPA determined that the volumes of these SBF (or OBF) well intervals were, in barrels, 565 for SWD, 1,184 for SWE, 855 for DWD, and 1,901 for DWE.

EPA gathered information from the Department of Interior Minerals Management Service (MMS), the Texas Railroad Commission and the Alaska Oil and Gas Commission, to estimate the number of wells drilled annually in each of the three regions where drilling is currently active and drilling wastes may be discharged. To forecast the number of wells drilled annually EPA averaged the number of wells drilled in 1995, 1996, and 1997. Based on information from the industry, MMS, and DOE, EPA then applied the following projections to determine the number of wells drilled by drilling fluid type:

(i) On a drilling performance basis SBF is equivalent to OBF.

(ii) Development and exploratory wells have equal requirements for SBF/OBF performance.

(iii) In GOM as a whole, 10 percent of all wells use SBF, 10 percent use OBF, and 80 percent use WBF exclusively. However, no OBF is used in the deepwater due to the potential of spills, and due to higher performance requirements 75 percent of all wells in GOM deep water are drilled with SBF. The remaining 25 percent are drilled exclusively with WBF.

(iv) In offshore California and coastal Cook Inlet, Alaska, OBF is used in the same frequency as SBF/OBF in the GOM (75 percent of wells in deep water and 13.2 percent of wells in shallow water). The remainder of wells use WBF exclusively and no SBF is used.

Also based on information from the industry, MMS, and DOE, EPA determined the following concerning the conversion of SBF to OBF and vice versa:

(i) For the discharge option, 20 percent of GOM OBF wells convert to SBF, and all OBF wells are in the shallow water. All offshore California and Cook Inlet, Alaska OBF wells convert to SBF.

(ii) For the zero discharge option, shallow water GOM SBF wells convert to OBF. However, deep water GOM SBF wells do not convert, because SBFs provide advantages in terms of eliminating OBF spills in the event of riser disconnect. Offshore California and Cook Inlet, Alaska OBF wells remain OBF wells.

Details of the how EPA made these determinations are provided in the Development Document.

Table IX–1 presents the total number of wells that EPA estimates will be drilled annually, by drilling fluid, for both the discharge option and the zero discharge option. EPA has distinguished wells as either ''existing'' sources of drill cuttings for BPT, BCT and BAT cost and pollutant reductions analysis, or ''new'' sources of drill cuttings for NSPS cost and reductions analysis.

TABLE IX–1.—ESTIMATED NUMBER OF WELLS DRILLED ANNUALLY PER REGULATORY OPTION BY DRILLING FLUID

Type of well	Shallow water (<1,000 ft)		Deep water (>1,000 ft)		Total
	Develop.	Explor.	Develop.	Explor.	
Gulf of Mexico:					
Baseline All Wells [1]	645	358	48	76	1127
Baseline SBF Wells	13	7	36	57	113
Discharge Option SBF Wells	[2] 28	15	[3] 36	57	136
Zero Discharge Option SBF Wells	0	0	36	57	93
Offshore California: [4]					
Baseline All Wells	11	0	15	0	26
Baseline OBF Wells	1	0	11	0	12
Discharge Option SBF Wells	1	0	11	0	12
Coastal Cook Inlet, Alaska: [4]					
Baseline All Wells	7	1	0	0	8
Baseline OBF Wells	1	0	0	0	1

TABLE IX–1.—ESTIMATED NUMBER OF WELLS DRILLED ANNUALLY PER REGULATORY OPTION BY DRILLING FLUID—Continued

Type of well	Shallow water (<1,000 ft)		Deep water (>1,000 ft)		Total
	Develop.	Explor.	Develop.	Explor.	
Discharge Option SBF Wells	1	0	0	0	1

[1] While this table lists total number of wells, the only wells included in the analysis are those affected by this rule: SBF wells or wells converting from OBF to SBF in discharge option or converting from SBF to OBF in zero discharge option.
[2] EPA assumes that 95 percent of GOM shallow water development wells of this analysis are existing sources, and 5 percent are new sources (equals one new source well).
[3] EPA assumes that 50 percent of GOM deep water development wells of this analysis are existing sources, and 50 percent are new sources (equals 18 new source wells).
[4] EPA assumes all offshore California and Cook Inlet, Alaska, wells are existing sources, and in discharge option all OBF wells convert to SBF wells.

By multiplying the compliance costs and discharge loadings determined from the model well analysis, EPA calculated the total cost to the industry and the reduction in pollutant loadings, as detailed in the following sections.

C. Method for Estimating Compliance Costs

1. Introduction and Summary

The costs considered as part of the compliance cost analysis are only those that EPA believes will be incurred as a result of today's rule. These include costs and savings associated with the discharge, disposal, and recovery of SBF and OBF, costs associated with the technologies used to control and manage waste drill cuttings under the discharge and zero discharge options, and monitoring costs.

For each option and each geographic area, EPA estimated baseline costs from current industry waste management practices. Following this, EPA estimated the cost to comply with each option of today's rule. EPA then calculated the incremental compliance costs, or the difference between baseline costs and estimated compliance costs. Table IX–2 lists the total annual baseline, compliance, and incremental compliance costs calculated in each geographic area for both the discharge and zero discharge regulatory options.

As the values in Table IX–2 show, EPA estimates that today's proposed discharge option provides a savings to the industry of over $7 MM annually. Savings occur in the GOM among wells currently using SBF because, according to information available to the EPA, the value of SBF recovered by the model solids separation technology is $8.1 MM, while the cost of implementing this technology is only $3.1 MM. Thus, this regulatory requirement leads to an annual net savings of $5.0 MM.

Savings in the GOM also occur for the OBF wells that switch to SBF, because the increased cost of SBF is less than the savings in disposal costs for OBF-cuttings. However, EPA has assumed that only 20 percent to the wells currently drilled with OBF in the GOM will switch to SBF because of the risk of losing more valuable SBF downhole. These OBF wells that convert are in the shallow water. EPA determined that any deep water well operating in the Gulf of Mexico that prefers to use SBFs has already converted to SBF. Savings also result in offshore California and Cook Inlet, Alaska when OBF wells convert to SBF wells, again because the increased cost of SBF is less than the savings in disposal cost of OBF-cuttings. In these areas, EPA assumed that all OBF wells switch to SBF because of more difficult and expensive zero discharge options for OBFs in these areas, and air quality considerations in California.

TABLE IX–2.—SUMMARY ANNUAL BASELINE, COMPLIANCE, AND INCREMENTAL COMPLIANCE COSTS FOR MANAGEMENT OF SBF CUTTINGS, EXISTING AND NEW SOURCES

[1997$/year]

Technology basis	Gulf of Mexico	Offshore California	Cook Inlet, Alaska	Total
Baseline Costs:				
Discharge with 11% retention of base fluid on cuttings	$21,315,375	([1])	([1])	$21,315,375
Zero Discharge (current OBF-drilled wells only)	2,821,816	$2,157,023	$207,733	5,186,572
Total Baseline Costs per Area	21,935,466	2,157,023	207,733	24,300,222
Compliance Costs:				
Discharge with 7% retention of base fluid on cuttings	17,582,675	1,647,883	115,467	19,346,025
Zero Discharge via land disposal or on-site injection	29,873,689	0	0	29,873,689
Incremental Compliance Costs (Savings):				
Discharge Option	(6,554,516)	(509,140)	(92,265)	(7,155,921)
Zero Discharge Option	8,558,314	0	0	8,558,314

[1] Not applicable.

To summarize the effects of today's proposed rule, the values listed in Table IX–2 above include both existing and new sources. The values for new sources alone are provided below in Table IX–3. The values for existing sources alone may be obtained by subtracting these values from the corresponding values in Table IX–2.

As shown in Table IX–1, EPA estimated that new source wells are located only in the Gulf of Mexico because of the lack of activity in new lease blocks in offshore California and coastal Cook Inlet. New source wells are defined in the offshore guidelines, 40 CFR Part 435.11(q), and exclude exploratory wells by definition (EPA, 1993; EPA, 1996).

TABLE IX–3.—SUMMARY ANNUAL BASELINE, COMPLIANCE, AND INCREMENTAL COMPLIANCE COSTS FOR MANAGEMENT OF SBF CUTTINGS FROM NEW SOURCES

[1997/year]

	Technology basis	Costs (savings)
Baseline Costs	Discharge with 11% retention of base fluid on cuttings	$2,201,725
NSPS Compliance Costs	Discharge with 7% retention of base fluid on cuttings	1,632,125
	Zero Discharge via land disposal or on-site injection	3,796,143
Incremental NSPS Compliance Costs	Discharge with 7% retention of base fluid on cuttings	(569,600)
	Zero Discharge via land disposal or on-site injection	1,594,418

The NSPS cost analysis consists of the same line-item costs as in the analysis for existing sources, with the exception that retrofit is not necessary on new platforms. The baseline for NSPS costs differs from the baseline for existing sources in that it includes only SBF wells that discharge cuttings and does not include any OBF wells practicing zero discharge.

2. Baseline Costs: Current Industry Practice

As noted above, the only cost elements included in the baseline are those that EPA anticipates will change as a result of the rule. The line items in the baseline cost analysis for those Gulf of Mexico wells that currently drill with SBF consist of the cost of SBF lost with the discharged cuttings and the cost of the currently-required SPP toxicity monitoring test. The baseline analysis for currently discharging wells assumes the cuttings are being treated by standard solids control equipment to an average 11 percent retention of synthetic material (base fluid) on the cuttings, on a wet-weight basis. As detailed in Section VI of today's notice and the Development Document, this baseline level of treatment is derived from data submitted in a report prepared for the American Petroleum Institute (API) (Annis, 1997). No baseline costs are attributed to the operation of solids control equipment that are standard in all drilling operations.

For existing sources, the unit baseline cost for wells that currently use SBF is $82/bbl. The unit baseline costs for SWD and SWE wells currently drilled with OBF are $96/bbl and $91/bbl, respectively. The development of the baseline costs for OBF wells is detailed under Section IX.C.4 ''Zero Discharge Compliance Costs.'' Table IX–2 lists the total baseline costs for each geographic area.

The unit baseline cost for the new source wells is $82/bbl for both DWD and SWD wells, and the total baseline cost is $2.2 MM.

In offshore California and coastal Cook Inlet, Alaska, current industry practice is zero discharge of OBF-cuttings. The line-item costs of these wells include costs for transporting and disposing of waste drill cuttings at commercial land-based disposal facilities, and the cost of the drilling fluid that adheres to and is disposed with the cuttings. EPA assumes that the drilling fluid lost with OBF-cuttings is a mineral oil-based fluid. For current industry practice, transportation of OBF-cuttings in the offshore California analysis consists of hauling via supply boat followed by trucking to a land-based facility. Transportation for the Cook Inlet analysis also consists of supply boats followed by trucks that haul the waste cuttings to a land-based disposal facility. However, due to the limited availability of disposal facilities in the Cook Inlet area, costs were developed for hauling the waste to a facility in Oregon. This approach to zero-discharge cost estimating for Cook Inlet was adopted from the Coastal Oil and Gas Rulemaking effort (EPA, 1996).

The unit baseline costs in offshore California are $128/bbl for DWD wells and $131/bbl for the SWD wells. The unit baseline cost for the model Cook Inlet well is $218/bbl. Again, multiplying the unit costs by the volume of waste cuttings for each model well type and by the numbers of wells estimated to be drilled annually in each category provides the total annual baseline costs for each region. The total annual baseline costs for offshore California and Cook Inlet are $2.2 MM and $0.2 MM, respectively (see Table IX–2).

3. Discharge Option Compliance Costs

The discharge option compliance cost analysis estimates the cost to discharge SBF-cuttings following secondary treatment by a solids control device that, when added on to other standard solids control equipment, reduces the average retention from 11 percent to 7 percent base fluid on wet cuttings. Line-item costs in the discharge option analysis consist of: a) costs associated with the use of an add-on solids control device, b) cost to retrofit platform space to accommodate the device, c) the value of the SBF discharged with the cuttings, and d) the cost of performing the waste monitoring analyses of today's proposal.

The wells in the discharge analysis for the Gulf of Mexico consist of those that are currently drilled with SBF and discharging SBF-cuttings, and those currently drilled using OBF that EPA estimates will convert to SBF. The cost of the add-on technology is the daily rental cost for the vibrating centrifuge device on which the seven percent retention is based. The rental cost includes all equipment, labor and materials, and was quoted by a Gulf of Mexico operator who used the device in an offshore demonstration project (Pechan-Avanti, 1998). Retrofit costs were assigned to all existing sources but not to new sources. Analytical monitoring costs are included for the proposed crude oil contamination of drill cuttings test and retort analysis for SBF retention on cuttings.

For existing sources, based on the above line-item costs, the unit discharge option costs for DWD and DWE wells are $74/bbl and $72/bbl, respectively. The unit discharge option costs for the SWD and SWE wells are $77/bbl and $74/bbl, respectively. The total annual discharge compliance cost for existing source Gulf of Mexico wells is $16 MM (see Table IX–2). The discharge option unit costs for new source wells are $73/bbl for DWD wells and $75/bbl for SWD wells, and the total discharge option cost is $1.6 MM.

The compliance cost analyses for offshore California and coastal Cook Inlet, Alaska consist of the same line items: daily rental of the add-on vibrating centrifuge, retrofit space to accommodate the add-on equipment, cost of SBF lost with discharged cuttings, and analytical costs for proposed waste monitoring tests. The costs for these items are the same as those estimated for the Gulf of Mexico adjusted higher using geographic area cost multipliers developed in the Offshore Oil and Gas Rulemaking effort (EPA, 1993). Geographic area cost multipliers are the ratio of equipment installation costs in a particular region compared to the costs for the same equipment installation in the Gulf of

Mexico. The cost multipliers for offshore California and Cook Inlet are 1.6 and 2, respectively. The unit discharge option costs for offshore California wells are $118/bbl for DWD wells and $122 for SWD wells. The unit discharge option cost for the Cook Inlet SWD well is $147/bbl. The total annual discharge option compliance costs for offshore California and Cook Inlet are $1.6 MM and $0.1 MM, respectively, and the total annual industry-wide compliance cost for the discharge option is $17.7 MM, as shown in Table IX–2.

4. Zero Discharge Option Compliance Costs

The zero discharge compliance cost analysis includes Gulf of Mexico wells identified as currently being drilled with SBF. The method presented in this section was also applied to baseline OBF wells, as mentioned in the baseline costs section. The wells included in the offshore California and Cook Inlet analyses, and some shallow water Gulf of Mexico wells (i.e., those wells currently drilled with OBF) do not incur costs in the zero discharge option because they are at zero discharge in the baseline. Furthermore, the population of wells currently drilled with SBF is divided into those that are assumed to continue using SBF under zero discharge requirements due to other concerns (i.e., spills as a result of riser disconnect), and those that would convert to OBF under zero discharge requirements due to the economic incentive of a less costly waste management practice (i.e., all shallow water wells). This division is shown in Table IX–1.

Per-well zero discharge costs incorporate the assumption that, of all zero discharge cuttings generated in the Gulf of Mexico, 80 percent is hauled to shore for land-based disposal and 20 percent is injected on-site. Preliminary information gathered regarding the use of on-site injection in the Gulf of Mexico is inconsistent between sources, ranging from an estimated 10 percent to as much as 66 percent (Veil, 1998). Additional information indicates that, while some operators have expressed concern over uncertainties related to injection (e.g., the ultimate fate of the injected wastes and the costs associated with unsuccessful injection projects), interest in on-site injection has increased throughout the industry since the time of the Offshore Oil and Gas Rulemaking, and continues to grow. The Agency therefore solicits information regarding the number of wells that use on-site injection, the volume of drilling waste injected, the per-well and per-barrel costs, and the frequency of unsuccessful injection projects.

Line-item costs in the land disposal zero discharge analysis include commercial disposal facility costs, container rental costs, supply boat costs, and value of drilling fluid retained on cuttings. Commercial disposal facility costs were obtained from the major oil field waste management companies serving the Gulf of Mexico industry. Cuttings container size and rental rate were obtained from vendors. All wells in the analysis are assumed to have acquired the retrofit space needed to store an average of 12 cuttings boxes as part of the Offshore Oil and Gas Rulemaking effort (EPA, 1993), and therefore do not incur retrofit costs in this analysis. The value of retained drilling fluid is based on mineral oil OBF ($75/bbl) for shallow water wells (assuming they all convert to OBF under zero discharge requirements), and internal olefin SBF (at $200/bbl) for deep water wells (assuming they all still use SBF under zero discharge requirements). The unit land-disposal cost varies by model well type: $148/bbl for DWD wells, $106/bbl for DWE wells, $102/bbl for SWD wells, and $96/bbl for SWE wells. Unit disposal costs vary by well type because the amount of time it takes to fill the disposal ship varies by well type, and the cost for the disposal ship is per daily rate.

Line-item costs in the on-site injection zero discharge analysis include the day rate rental cost for a turnkey injection system, and lost drilling fluid costs. The injection system cost includes all equipment, labor, and associated services. The unit on-site injection cost is $121/bbl for deep water wells, and $71/bbl for shallow water wells.

The zero discharge compliance cost is the weighted average assuming 80 percent of wells use land disposal and 20 percent of wells use on-site injection to achieve zero discharge. For existing sources, the weighted average unit cost for zero discharge for the model wells is as follows: $143/bbl for DWD wells, $109/bbl for DWE wells, $96/bbl for SWD wells, and $91/bbl for SWE wells. The total annual zero discharge compliance cost resulting from this analysis is $26.1 MM (see Table IX–2).

For new sources, the weighted average unit costs are the same as for existing sources: $143/bbl for DWD wells and $96/bbl for SWD wells. The total zero discharge cost for new sources is $3.8 MM/year.

5. Incremental Compliance Cost

The incremental compliance cost is the difference between the baseline and the compliance cost, as presented in Table IX–2. The overriding factor in the Gulf of Mexico incremental discharge option cost is that, according to EPA analysis of SBF baseline wells, the value of the recovered SBF is greater than the cost of implementing the vibrating centrifuge model technology. This gives a net savings of $5.0 MM/year. A saving of $0.94 MM/year is also realized when existing wells currently using OBF convert to using SBF. EPA assumed for this calculation that 23 of the 112 OBF wells, or 20 percent, would convert. All of these are considered existing sources. Combining these two gives a total savings of $5.9 MM for Gulf of Mexico existing source wells in the discharge option.

Incremental discharge option costs for existing sources in offshore California and coastal Cook Inlet, Alaska include savings incurred as wells move from the zero discharge baseline to discharge, and increased cost of SBF over the baseline OBF cost. For both of these areas, the net incremental discharge compliance cost is negative, resulting in savings of $509,000/year for offshore California and $92,000/year for coastal Cook Inlet. Combined with the Gulf of Mexico savings, the total annual savings for existing sources in the discharge option is $6.6 MM.

The incremental new source compliance cost for the discharge option is $-0.57 MM/year, or a savings of $570,000.

For existing sources, the costs under the zero discharge option (total annual = $7.0 MM/year) are the costs that Gulf of Mexico baseline SBF wells incur moving from discharge to zero discharge. For new sources, the incremental cost for the zero discharge option is $1.6 MM/year.

As a sensitivity analysis, EPA performed two additional discharge option compliance cost analyses by varying the fraction of current Gulf of Mexico shallow water OBF wells that would convert to SBF after the rule. In the analysis presented above, EPA used an estimate of 20 percent, based on information provided by industry sources. Due to the uncertainty of predicting future industry activity, the Agency investigated the range of discharge option compliance costs that would result assuming that either zero percent of the OBF wells would convert to SBF use (maintain at 113 SBF wells) or 100 percent of the OBF wells would convert to SBF use (increase to 225 SBF wells). The ''zero percent convert'' analysis resulted in an annual incremental cost savings of $5.6 MM industry wide, and the ''100 percent convert'' analysis resulted in an annual incremental savings of $10.2 MM. The

savings for the ''20 percent convert'' analysis falls between these values, at $6.6 MM (see Table IX–2). Thus, regardless of the number of wells assumed to convert from OBF to SBF, the discharge option results in industry-wide incremental cost savings.

D. Method for Estimating Pollutant Reductions

The methodology for estimating pollutant loadings and incremental pollutant reductions effectively parallels that of the compliance cost analyses. The pollutant reduction analyses are based on the size and number of the four model wells identified in Table IX–1, as well as pollutant characteristics of the cuttings wastestream compiled from previous rulemaking efforts and from industry sources.

For wells that currently use SBFs and discharge SBF-cuttings in the Gulf of Mexico, EPA projects that the discharge option of this rule will decrease the discharges of SBFs by over 15.4 MM pounds annually due to the retention limit. However, EPA projects that certain OBF wells will convert to SBF wells, and these SBF wells would discharge 3.6 M pounds of SBFs annually. Therefore, EPA calculated that including this increased number of SBF wells, the discharge of SBF would be reduced just 11.8 MM pounds annually. Specifically, EPA projects that all OBF wells in offshore California and Cook Inlet, Alaska, and 20 percent, or 23 wells, of the OBF wells in the Gulf of Mexico, will convert to SBF. Also because of this conversion from OBF wells to SBF wells, EPA projects an increase in the annual discharge of dry drill cuttings of 25.9 MM pounds. With dry drill cuttings discharges increasing 25.9 MM pounds and SBF discharges decreasing 11.8 MM pounds, EPA projects that the discharge option of this rule would lead to an overall increase in discharges of 14.1 MM pounds annually.

Table IX–4 lists the total annual baseline pollutant loadings, compliance pollutant loadings, and incremental pollutant reductions calculated for existing and new sources.

TABLE IX–4.—SUMMARY ANNUAL POLLUTANT LOADINGS AND INCREMENTAL REDUCTIONS FOR EXISTING AND NEW SOURCES

[Lbs/year] [1]

	Gulf of Mexico	Offshore California	Cook Inlet, Alaska	Total
Baseline Technology Loadings:				
Discharge with 11% retention of base fluid on cuttings	177,390,660	0	0	177,390,660
Zero Discharge (current OBF-drilled wells only)	0	0	0	0
Compliance Option Loadings:				
Discharge with 7% retention of base fluid on cuttings	180,527,712	10,420,876	590,550	191,539,138
Zero Discharge via land disposal or on-site injection	0	0	0	0
Incremental Pollutant Loadings (Reductions):				
Discharge with 7% retention of base fluid on cuttings	3,137,028	10,420,876	590,550	[1] 14,148,454
Zero Discharge via land disposal or on-site injection	(177,390,660)	0	0	(177,390,660)

[1] Consists of 11.8 MM pounds decreased discharge of SBF, 17,366 pounds decreased discharge of formation oil, and 25.9 MM pounds increased discharge of drill cuttings.

In order to act as a summary, the values in Table IX–4 above combine the effects of both existing and new sources. The values for existing sources alone may be determined by subtracting the corresponding values for new sources that are presented in Table IX–5.

In the calculation of per-well pollutant loadings and incremental pollutant reductions, a list of pollutant characteristics was developed in the same manner as the pollutant reduction analyses performed in the Coastal Oil and Gas Rulemaking effort (EPA, 1996). The pollutant list consists of conventional, priority, and non-conventional pollutants. Conventional pollutants include total suspended solids (TSS) and oil and grease. The TSS derives from two sources: the drill cuttings and the barite in the adhering drilling fluid. The drilling fluid is assumed to contain an average 33 percent (by weight) barite and 47 percent (by weight) synthetic base fluid (drilling fluid formulation data were calculated from data provided in the 1997 API report by Annis). Metals, both priority and non-conventional, derive from the barite in the adhering drilling fluid. In the Offshore Oil and Gas Rulemaking, EPA concluded that barite is the primary source of metals in drilling fluid (EPA, 1993). The metal concentrations from the Offshore analysis were adopted for this analysis. In terms of loadings the synthetic base fluid adhering to the cuttings, plus an assumed 0.2 percent (by volume) of formation oil contamination, are considered oil and grease. EPA recognizes, however, that there are nonconventional components of the SBF base fluids and formation oil. The 0.2 percent (vol.) of formation oil in the wastestream is assumed because EPA believes that this concentration would occasionally be found in drilling fluids, and would meet the effluent limitation in today's proposal. The organic pollutants, both priority and non-conventional, derive from the formation oil contamination. The specific organic pollutant concentrations were obtained from analytical data presented in the Offshore Oil and Gas Development Document for Gulf of Mexico diesel (EPA, 1993). The SBF base fluids are considered non-conventional pollutants.

In the discharge option, for each model well two sets of calculations were developed, based on 11 percent and 7 percent retention, to determine the per-well volumes of synthetic base fluid, water, barite, dry cuttings and formation oil in the wastestream. The calculations were based upon the assumed drilling fluid formulation of 47% (wt.) synthetic base fluid, 20% (wt.) water, and 33% (wt.) solids as barite, the retention values, and the 0.2% (vol.) formation oil contamination. Details of these calculations are presented in the Development Document.

The waste volume estimates resulting from the above calculations were applied to the pollutant concentrations to determine the per-well pollutant loadings and incremental pollutant reductions. As in the compliance cost analysis, the per-well values were then multiplied by the numbers of wells in each option and each geographic area (see Table IX–1) to determine the total industry-wide pollutant loadings and reductions. For baseline SBF wells that discharge, baseline pollutant loadings were calculated at 11 percent retention, according to information gathered by

the industry using currently available technology. EPA calculated the incremental pollutant reduction as these wells move to the discharge option at an average SBF base fluid retention on cuttings of 7 percent.

For baseline OBF wells that do not discharge, the baseline loadings are zero. As baseline wells that do not discharge move to the discharge option, EPA calculated a loading increase at seven percent retention. This occurs for wells in offshore California, coastal Cook Inlet, and a fraction of OBF wells in the Gulf of Mexico that EPA assumes will convert to SBF subsequent to this rulemaking.

EPA projected that balancing the reductions in per-platform discharge due to the retention limit with the increased number of platforms discharging SBF-cuttings leads, annually, to the decrease in discharge of SBFs of 11.8 MM pounds, the decrease in formation oil discharge of 17,366 pounds, and the increase in drill cuttings discharge of 25.9 MM pounds. This yields a net increase of 14.1 MM pounds discharged annually in the discharge option.

The incremental pollutant reduction for the zero discharge option is elimination of the baseline loading of currently discharging wells at 11 percent retention. Table IX–4 shows the annual incremental pollutant reduction for the zero discharge option is 159 MM pounds.

As stated in section IX.C.4, EPA investigated the range of incremental compliance costs and pollutant reductions assuming that, in the discharge option, either zero percent or 100 percent of current OBF wells in the GOM would convert to SBF. EPA further assumed that all OBF wells in the GOM are in the shallow water. The analysis above is based on 20 percent of the OBF wells converting to SBF. The ''zero percent convert'' analysis resulted in an annual incremental pollutant reduction of 3 MM pounds industry wide, and the ''100 percent convert'' analysis resulted in an annual increase of discharges of 89.0 MM pounds per year. The increased discharges for the ''20 percent convert'' analysis falls between these values, at 15.8 MM pounds (see Table IX–4). In the 100 percent convert scenario, the 89 MM pounds consists of 76 MM pounds of dry cuttings and 13 MM pounds of associated SBFs.

The method of estimating pollutant loadings and reductions for new sources is the same as that for existing sources. As discussed in section IX.C.5, EPA estimated that 19 new source wells are located in the Gulf of Mexico, including one in the shallow water and 18 in the deep water (see also Table IX–1). For new sources, no OBF wells are in the baseline, because new sources would be projected to occur mainly in deep water, where operators generally prefer to use SBFs for cost, performance, and to minimize liability. In the new source analysis, there are pollutant discharge reductions for both the discharge option and the zero discharge option because all new source wells move from a baseline of discharge at an average 11 percent retention of synthetic base fluid on cuttings to discharge at seven percent retention under the discharge option or to zero discharge under the zero discharge option. The total annual NSPS incremental pollutant reductions are 1.6 MM pounds for the discharge option and 18.3 MM pounds for the zero discharge option. The discharge option reduction consists of 1.6 MM pounds of SBF, and a small amount (2,800 pounds) of formation oil.

TABLE IX–5.—SUMMARY ANNUAL POLLUTANT LOADINGS AND INCREMENTAL REDUCTIONS FOR MANAGEMENT OF SBF CUTTINGS FROM NEW SOURCES

[Lbs/year]

	Technology basis	Loadings/reductions
Baseline Loadings	Discharge with 11% retention of base fluid on cuttings	18,286,914
NSPS Pollutant Loadings	Discharge with 7% retention of base fluid on cuttings	16,676,538
	Zero Discharge via land disposal or on-site injection	0
Incremental NSPS Pollutant Reductions	Discharge with 7% retention of base fluid on cuttings	1,610,394
	Zero Discharge via land disposal or on-site injection	18,286,914

E. BCT Cost Test

The BCT cost test, described in section VI.E of today's notice, was not performed for either of the regulatory options investigated for this rulemaking. The BCT cost test evaluates the reasonableness of BCT candidate technologies as measured from BPT level compliance costs and pollutant reductions. In today's rulemaking, the proposed BCT level of regulatory control is equivalent to the BPT level of control for both the preferred discharge option and the zero discharge option. If there is no incremental difference between BPT and BCT, there is no cost to BCT and thus the option passes both BCT cost tests.

X. Economic Analysis

A. Introduction and Profile of the Affected Industry

This section presents EPA's estimates of the economic impacts that would occur under the regulatory options proposed here. The results of this analysis are described in more detail in the Economic Analysis of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category (EPA–821–B–98–020).

Under the preferred discharge option, the proposed effluent guidelines would provide a cost savings to industry. This cost savings would be experienced by wells currently discharging cuttings contaminated with SBFs and by wells currently using OBF and switching to SBF as a result of this rule. As discussed in Section IX, the cost savings for current SBF dischargers result from the use of improved solids control equipment, allowing operators to recycle additional volumes of expensive SBFs, which more than offsets the costs of the improved solids control equipment. For wells that would have been drilled with OBF, the cost savings result from switching to SBF and discharging, thus avoiding higher disposal costs of zero discharge. Operations using and discharging WBFs would not incur costs or realize costs savings under this rule because EPA does not expect operators to convert from WBFs to SBFs, as discussed above. This section of today's notice describes the segment of the oil and gas industry that would benefit from this rule (i.e.,

the number of firms and number of wells per year that would incur costs or realize savings under the proposed rule), the financial condition of the potentially affected firms, the aggregate cost savings to that segment, and any impacts that might arise as a result of the rule. The Agency also discusses impacts on small entities, presents a cost-benefit analysis, and discusses cost-effectiveness. EPA also evaluated a zero-discharge option, which was considered but not selected for proposal, and found it would have a minor impact on a few entities (large and small) operating in the affected offshore and coastal regions. This discussion will form the basis for EPA's findings on regulatory flexibility, presented in Section XI.B.

For this profile, EPA is relying on information developed by Minerals Management Service (MMS) for EPA. This information includes wells drilled in federal waters during 1995, 1996, and 1997, along with the MMS-assigned numbers identifying the operators. These data were summarized by MMS from MMS's Technical Information Management System. MMS grouped wells by location (Pacific and Gulf drilling operations were tallied separately), water depth (up to 999 ft and 1,000 ft or more), and by type (exploratory or development). MMS also provided a list of operators by operator number. EPA linked the name of the operators to wells drilled using the operator number. Names of all operators who had drilled any well in any of the three years were then compiled. EPA used the Security and Exchange Commission's (SEC's) Edgar database, which provides access to various filings by publicly held firms, such as 8Ks and 10Ks. The former documents are useful for determining mergers and acquisitions in more detail, and 10Ks provide annual balance sheet and income statements, as well as listing corporate subsidiaries. The information in the Edgar database was used to identify parent companies or recent changes of ownership. EPA also used a database maintained by Dun & Bradstreet (D&B), which provides estimates of employment and revenue for many privately held firms, and financial data compiled by Oil and Gas Journal on publicly held firms.

Other sources of data used in the economic analysis include the Development Document for this proposed rule; EPA, 1993, Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry (EPA 821/R–93–004); and EPA, 1995, Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category (EPA 821/R95–013).

For profiling purposes in all regions, EPA divided the potentially affected firms identified using the MMS, SEC, and D&B data into two basic categories. The first category consists of the major integrated oil companies, which are characterized by a high degree of vertical integration (i.e., their activities encompass both ''upstream'' activities—oil exploration, development, and production—and ''downstream'' activities—transportation, refining, and marketing). The second category of affected firms consists of independents engaged primarily in exploration, development, and production of oil and gas and not typically involved in downstream activities. Some independents are strictly producers of oil and gas, while others maintain some service operations, such as contract drilling and well servicing. EPA used the U.S.A. Oil Industry Directory, 37th Edition, 1998, published by PennWell Publishing Co., Houston, Texas, to identify firms as majors, independents, or foreign-owned.

The two types of oil and gas firms, majors and independents, are very different types of entities, in most cases. The major integrated oil companies are generally larger than the independents, and are often among the largest corporations in the world. As a group, the majors typically produce more oil and gas, earn significantly more revenue and income, and have considerably more assets and greater financial resources than most independents. Furthermore, majors tend to be relatively homogeneous in terms of size and corporate structure. Majors do not meet the definition of small firm under the Regulatory Flexibility Act (RFA). Most majors are C corporations (i.e., the corporation pays income taxes).

Independents vary greatly by size and corporate structure. Larger independents tend to be C corporations; small firms might also pay corporate taxes, but they also can be organized as S corporations (which elect to be taxed at the shareholder level rather than the corporate level under subchapter S of the Internal Revenue Code). Small firms also might be organized as limited partnerships, or sole proprietorships, whose owners, not the firms, pay taxes.

2. Profile of the Potentially Affected Oil and Gas Regions

a. *Gulf of Mexico.*—As discussed in Sections IV and IX of this notice, the Gulf of Mexico beyond 3 miles from shore is the most active of the four oil and gas regions concerning this proposed rule. Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores. Very little drilling is occurring off Mississippi, Alabama, and Florida. The Western Gulf Region also is associated with the majority of the current use and discharge of SBF cuttings.

As stated above, the rule would apply only where WBFs and associated drill cuttings may be discharged, i.e., 3 miles or more from shore. Using the MMS, SEC, and D&B data discussed above, EPA accounted for the various corporate relationships and transactions to determine the total number of firms actively drilling in the affected regions of the Gulf. EPA counted 96 potentially affected firms at the parent company level in the Gulf of Mexico, of which 15 are considered majors. Twelve of the 96 firms are identified as foreign-owned (not including U.S. majors such as Shell Oil, which is affiliated with Royal Dutch/Shell Group), and these firms are included in the analysis. Non-foreign independents are estimated to total 69 firms.

Financially, the potentially affected operators are a healthy group of firms. Among publicly held firms, median return on assets for the group is 4.3 percent, median return on equity is 10.2 percent, and median profit margin (net income/revenues) is 6.6 percent, according to 1997 financial data. Among these publicly held firms, 60 out of 69 firms, or 87 percent, reported positive net income for 1997.

As discussed above in Section IX, EPA estimates that an average of 1,127 wells are drilled each year in the Gulf of Mexico, of which 1,108 are considered to be existing wells and 19 are considered to be new sources. EPA estimates (see Section IX) that each year 113 wells are drilled using SBFs and 112 are drilled using OBFs for at least a portion of the drilling operation. Of the 112 wells drilled with OBFs, EPA estimates that 20 percent, or 23 wells, would convert from OBF to SBF as a result of this rule. These wells are all assumed to be located in shallow water (see Table IX–1 in Section IX). The remaining 902 wells that are drilled annually in the Gulf of Mexico are assumed to be drilled exclusively using WBFs and would not incur costs or realize savings under the proposed rule.

b. *Offshore California.*—Most production activity in the Offshore California region is occurring in an area 3 to 10 miles from shore off of Santa Barbara and Long Beach, California. There are five operators actively drilling

(1995–1997) in the California Offshore Continental Shelf (OCS) region. These operators are Chevron; Aera Energy, LLC; Exxon; Torch Energy Advisors; and Nuevo Energy Co. Detailed information on Torch Energy Advisors (other than employment and revenues) and Aera Energy is not available. Among the remaining firms, median return on assets is 9.0 percent, median return on equity is 18.6 percent, and median profit margin is 5.7 percent. No operators reported negative net income among publicly held firms. Thus, the California firms, like the Gulf firms, generally appear to be financially healthy.

As discussed in Section IX, EPA estimates that an average of 26 development wells and no exploratory wells are drilled in the California OCS each year. EPA further estimates that no wells are currently drilled using SBFs and 12 wells are drilled each year using OBFs. EPA assumes that all 12 of these OBF wells convert to SBF as a result of this rule. All wells are considered existing sources. EPA assumes the remaining 14 wells are drilled exclusively using WBFs and are thus would not incur costs or realize savings under this proposed rule (see Table IX–1 in Section IX).

c. *Cook Inlet, Alaska.*—Cook Inlet, Alaska, is divided into two regions, Upper Cook Inlet, which is in state waters and is governed by the Coastal Oil and Gas Effluent Guidelines, and Lower Cook Inlet, which is considered Federal OCS waters and is governed by the Offshore Oil and Gas Effluent Guidelines. Lower Cook Inlet is discussed as part of the Alaska Offshore region in Section X.A.2.d below. All references to Cook Inlet mean Upper Cook Inlet unless otherwise identified.

Three operators are currently active in Cook Inlet: Unocal, Phillips, and Shell (as Shell Western). All three are major integrated oil firms, and all three also operate in the Gulf of Mexico. In addition, ARCO also has been involved in exploratory drilling in the Sunfish Field, but Alaska state data indicate that Phillips bought ARCO's interests in this field and will pursue any drilling from its Tyonek platform. Median return on assets for this group is 7.1 percent, median return on equity is 14.1 percent, and median profit margin is 7.3 percent. No firm reported negative net income in 1997. Again, these firms appear financially healthy.

Over the past three years (1995–1997) operators have drilled an average of about 7 wells per year (see Table IX–2 in Section IX). EPA estimates that no off-platform drilling will be undertaken in Cook Inlet. Thus for the purpose of estimating impacts for today's proposal, EPA assumes seven wells per year will be drilled in Cook Inlet, and all are considered existing sources. No operators currently use SBFs in Cook Inlet. Of the seven wells drilled in Cook Inlet, EPA estimates that one well per year might be drilled annually using OBFs, and as a result of this rule, this OBF well would convert to SBF.

d. *Offshore Alaska.* The offshore Alaska region comprises several areas, which are located both in state waters and in federal OCS areas. The most active area for exploration has been the Beaufort Sea, the northernmost offshore area on the Alaska coastline. Other areas where some exploration has occurred include Chukchi Sea to the northwest, Norton Sound to the West, Navarin Basin to the west, St. George Basin to the southwest, Lower Cook Inlet to the south, and Gulf of Alaska, along the Alaska panhandle. The only commercial production is occurring in the Beaufort Sea region.

To EPA's knowledge, no operations are discharging any drilling fluids or cuttings in the offshore Alaska region. No discharge is occurring in state waters due to state law requiring operators to meet zero discharge. In the federal offshore region, the Offshore Guidelines do not specifically prohibit discharge of SBF cuttings, but all operators historically have injected their drilling wastes. No commercial production has occurred in any federal offshore area. Some promising finds have been made in federal offshore waters in recent years, but development may be several years off. These fields include the Liberty (Tern Island) Field and the Northstar Field, both in the Beaufort Sea. Currently a draft Environmental Impact Statement (EIS) is being prepared for the Liberty Field. The Northstar Field has encountered significant resistance to development. The operator (BP) halted construction for over one year as a result of a recently resolved lawsuit and has just begun the task of preparing a final environmental impact statement, which must be finalized before any production operations can proceed.

Since the beginning of exploration in the Alaska Offshore region, 82 exploratory wells have been drilled in Federal Offshore waters, primarily in the Beaufort Sea, where nearly 40 percent of all exploratory wells in the Alaska federal offshore region have been drilled. Exploratory well drilling in federal waters has slacked off significantly in recent years. From a peak of about 20 wells per year in 1985, no wells were drilled in 1994, 1995, and 1996, and two were drilled in 1997, for an average of less than one well drilled per year. EPA assumes that no significant drilling activity will be occurring in the Federal Offshore regions of Alaska. Offshore Alaska, therefore, is within the scope of the regulation but is not expected to be associated with costs or savings as a result of the proposed effluent guidelines, either in state offshore waters (because of state law) or in federal waters (due to historic practice and lack of drilling activity). Wells drilled in this region are not included in the count of potentially affected wells.

3. Summary of Well Counts and Operators

EPA estimates that a total of 1,160 wells, on average, are drilled each year in the regions potentially affected by the SBF Guidelines. Of these, EPA estimates that 113 wells are drilled, on average, each year using SBFs in the Gulf (none in California and none in Cook Inlet). EPA further estimates that a total of 125 wells are drilled annually using OBFs, of which 112 are drilled in the Gulf, 12 in California, and 1 in Cook Inlet. EPA estimates that the remaining 922 wells drilled annually in the affected regions are drilled exclusively with WBFs and would not incur costs or realize savings under the proposed rule. EPA assumes that a total of 23 wells in shallow water locations, 12 wells in California, and 1 well in Cook Inlet, for a total of 36 wells, would switch from OBFs to SBFs if the SBF effluent guidelines allow discharge.

The number of operators currently drilling wells in the regions total 99 firms. These operators include the 96 operators in the Gulf of Mexico and 3 additional operators in the Pacific (2 Pacific operators also drill in the Gulf). All Cook Inlet operators also drill in the Gulf. These counts will be used as baseline data for the economic analysis.

B. Costs and Costs Savings of the Regulatory Options

EPA considered two options for the proposed rule for both BAT and NSPS, a discharge option and a zero discharge option. Table X–1 summarizes the costs and costs savings of each alternative considered in this rule under both BAT and NSPS. This information was presented in more detail in Section IX. For additional information, see Tables IX–2 and IX–3 in Sections IX.C.

TABLE X–1.—COSTS AND COST SAVINGS OF THE REGULATORY OPTIONS

Option	BAT	NSPS	Total
Discharge	($6,586,322)	($569,600)	($7,155,922)
Zero Discharge	$6,963,896	$1,594,418	$8,558,314

As Table X–1 shows, the preferred discharge option is associated with a cost savings of $6.6 million per year for BAT and $0.6 million per year for NSPS, for a total cost savings of $7.2 million per year. The cost estimates for the zero discharge option are $7.0 million per year under BAT and $1.6 million per year under NSPS, for a total of $8.6 million per year.

C. Impacts from BAT Options

For each regulatory option, EPA estimated the change in the cost of drilling wells, impacts on operating a production unit (typically a platform), impacts on firms, both large and small (impacts on small firms specifically are discussed in Section X.F), employment impacts in the oil and gas industry, and impacts on related industries (e.g., drilling contractors, drilling fluid companies, mud cleaning equipment rental firms, transport and disposal firms, etc.) as a result of the proposed BAT requirements. The results of these analyses are summarized below. EPA concludes that, for the preferred option, nearly all economic impacts are positive and finds the preferred option to be economically achievable in the regions analyzed, as well as for any other region where discharge would be allowed.

1. Impacts on Costs of Drilling Wells

In this section, EPA shows the impacts of the costs associated with this rule by comparing per-well costs with the total average cost to drill a well. Table X–2 shows the four model well types defined in Section IX and provides estimates of potential costs or cost savings as a percentage of total costs to drill a well associated with various subsets of these well types. Costs and cost savings vary depending on the region, the type of fluid currently used, and the operator's choice of zero discharge (under the zero discharge option only)—hauling to shore for disposal or injecting the waste (the latter, less expensive option is not technically feasible at all locations). See the Development Document for detailed information on how the numbers of wells were estimated in each category and the Economic Analysis report for how the aggregate costs of each well type were disaggregated to estimate a per well cost.

TABLE X–2.—COST SAVINGS OF THE IMPROVED DISCHARGE OPTION AS A PERCENTAGE OF BASELINE DRILLING COSTS

[$1997]

Type of well	Number of wells	Incremental cost of discharge option (per well)	Incremental cost of zero discharge option (per well)	Total baseline cost of drilling well ($MM)	Cost as a percentage of total drilling cost	
					Discharge option	Zero discharge option
Gulf of Mexico:						
Deep Water SBF Developmental (haul)	14	($29,302)	$95,507	$2.9	−1.0	3.3
Deep Water SBF Developmental (inject)	4	(29,302)	57,205	2.9	−1.0	2.0
Shallow Water SBF Developmental (haul)	10	(17,502)	19,113	2.9	−0.6	0.7
Shallow Water SBF Developmental (inject)	2	(17,502)	[1] (10,555)	2.9	−0.6	−0.4
Shallow Water OBF Developmental (haul)	12	(36,615)	0	2.9	−1.3	0.0
Shallow Water OBF Developmental (inject)	3	(6,947)	0	2.9	−0.2	0.0
Deep Water SBF Exploratory (haul)	46	(70,502)	79,813	3.9	−1.8	2.0
Deep Water SBF Exploratory (inject)	11	(70,502)	127,825	3.9	−1.8	3.3
Shallow Water SBF Exploratory (haul)	6	(41,502)	28,315	4.9	−0.8	0.6
Shallow Water SBF Exploratory (inject)	1	(41,502)	[1] (21,950)	4.9	−0.8	−0.4
Shallow Water OBF Exploratory (haul)	6	(69,817)	0	4.9	−1.4	0.0
Shallow Water OBF Exploratory (inject)	2	(19,552)	0	4.9	−0.4	0.0
California:						
Deep Water OBF Developmental	11	(43,658)	0	1.6	−2.7	0.0
Shallow Water OBF Developmental	1	(28,899)	0	1.6	−1.8	0.0
Alaska:						
Shallow Water OBF Developmental	1	(92,266)	0	2.8	−3.3	0.0

[*] See Development Document for explanation of cost savings.

Note: Negative values or values in parentheses represent a cost savings.

Table X–2 shows that most cost savings under the preferred discharge option would be about 1 to 2 percent of total well drilling costs, with a few exceptions. Deep water development wells using OBFs in California would realize cost savings of as much as 2.7 percent of total costs, and the estimated one Alaska well using OBFs in Cook Inlet would realize a cost savings of 3.3 percent of total well drilling costs. In general, these cost savings are not a large portion of costs to drill and therefore should act as no incentive to at most a small incentive on well drilling activity.

Under zero discharge, wells currently using OBFs would incur no incremental costs of compliance since they already meet zero discharge requirements. Among those currently using SBFs, the median percentage of compliance costs to the total cost of drilling wells is 2.0 percent. EPA believes these results indicate that the rule would be economically achievable, but has selected the discharge option instead in

order to mitigate non-water quality environmental impacts; see Section VI above.

2. Impacts on Platforms and Production

Neither the discharge option nor the zero discharge option would have a significant impact on production decisions on platforms. As noted above, cost savings among operations currently using SBFs are a small fraction of the overall cost to drill a well in the offshore, so the cost savings associated with the preferred discharge option would have a small effect on an operator's decisions to drill, although some small encouragement to drilling may result.

Under EPA's zero discharge option, EPA investigated potential impacts based on previous work performed as part of the offshore oil and gas effluent guidelines rule. The costs of such an option, compared to the baseline costs of drilling wells in the Gulf are presented in Table X–2. EPA previously investigated the impact of zero discharge of all drilling fluids and cuttings on platform-based production operations in the offshore regions of the Gulf and found, at that time, that ''none of the options considered * * * [including zero discharge] for drilling fluids and drill cuttings has an adverse impact on hydrocarbon production.'' (58 FR 12,454–12,152). Furthermore, as stated in the economic impact analysis prepared for the rule (Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry, EPA 821/R–93–004), EPA estimated no change in the total production for any project analyzed under any regulatory scenario for drilling wastes (including zero discharge). EPA believes that a similar impact would occur today and thus zero discharge would be economically achievable.

3. Impacts on Firms

EPA estimated impacts on firms by assessing the costs and cost savings of the regulatory options as a percentage of revenues. The cost savings associated with the preferred discharge option would have from no impact to a very small impact on the investment decisions by the majority of the firms affected by the proposed rule. EPA assumes that the likeliest users of SBF in shallow water locations are the same operators who use SBF in deep water operations. EPA solicits comments on this assumption. In the Gulf of Mexico, a total of 18 firms (19 percent of the 96 firms considered potentially affected in the Gulf) drilled in deepwater locations over the period 1995–1997. Total cost savings among these firms would probably be at most nearly 0.3 percent of revenues.

Among the 18 firms likely to be using SBFs (the 18 deepwater drilling firms), costs of zero discharge of SBF cuttings would be at most 0.4 percent of revenues among these firms. Section X.F discusses costs for zero discharge as a percent of revenues for each potentially affected small firm currently drilling with SBFs and discharging cuttings.

4. Secondary Impacts

a. *Employment and Output.*—EPA anticipates no negative impacts on employment and output (revenues) from the preferred option because, in the aggregate, cost savings are realized. Changes in employment and output are directly proportional to costs of compliance (that is, higher costs lead to lower employment and output) thus cost savings would minimally increase employment and output in the oil and gas industry, but these gains would be offset by losses elsewhere in the economy (e.g., waste disposal firms). Under zero discharge, the costs of compliance would minimally decrease employment and output, but these decreases would be offset by gains elsewhere in the economy (e.g., waste disposal firms).

The gross effects of the preferred option (that is, without considering losses in other industries that were not quantified) would total 93 full-time equivalents (FTE) gained in the U.S. economy (1 FTE = 2,080 hours and can be equated with one full-time job) and $13.9 million in additional output per year throughout the U.S. economy as a whole. The zero discharge option is estimated to result in a loss (unadjusted for gains in other industries, which EPA did not quantify) of 111 FTEs and a loss of $16.6 million in output per year in the U.S. economy. These losses occur within the oil and gas industry as well as in other industries. The net effect of the rule (once adjustments for changes in other industries are accounted for) on the U.S. economy under either option is likely to be close to zero.

To the extent that any costs savings might be reinvested in additional drilling or otherwise encourage additional drilling, employment and output could increase in the oil and gas industry by more than that associated with the cost savings alone. EPA has not quantified this potentially positive, albeit very small, effect.

b. *Secondary Impacts on Associated Industries.*—EPA qualitatively analyzed the secondary impacts on associated industries from the preferred option. Impacts on drilling contractors should be neutral to positive, with some increase in employment in these firms occurring if they reinvest the cost savings. Impacts on firms supplying drilling fluids should be neutral to positive, since most firms supplying drilling fluids stock both OBFs and SBFs. To the extent that SBFs have, at a minimum, the same profit margin as OBFs, there would be little to no impacts on these firms, because SBFs would replace OBFs in some instances under the preferred discharge option. If drilling increases as a result of reinvestment, some positive impacts might occur.

Firms that provide rental of solids separation systems presumably would purchase and provide improved solids separation systems once demand for these systems developed with the promulgation of the rule. Because these more efficient systems would most likely be rented in addition to, rather than in place of, less efficient systems, impacts on these firms would be positive.

Firms that manufacture the improved solids separation equipment and firms that manufacture equipment or provide services needed to comply with the new testing requirements would prosper.

The firms providing transport and landfilling or injection of OBF-contaminated cuttings would sustain economic losses as a result of the rule. Under the preferred option, for wells currently using OBFs, EPA estimates that waste generated for disposal by landfill and injection would be reduced by 34 million pounds per year (see Section VII.E and Section X.E). Under a zero discharge option, these firms would experience potential economic gains, because more waste (178 million pounds per year) would be generated for land disposal or injection than is currently generated (see Section VII.E and Section X.E).

c. *Other Secondary Impacts.*—There would be no measurable impacts on the balance of trade or inflation as the result of this proposed rule. EPA projects insignificant impacts on domestic drilling and production, and therefore insignificant impacts on the U.S. demand for imported oil. Additionally, even if there were costs associated with this rule, the industry has no ability to pass on costs to consumers as price takers in the world oil market, and thus this rule would have no impact on inflation.

D. Impacts From NSPS Options

The proposed NSPS option is the same discharge option proposed for BAT. Under the definitions of new

source in the Offshore Oil and Gas Effluent Guidelines, an oil and gas operation is considered a new source only when significant site preparation work and other criteria are met (see 40 CFR Part 435.11). Individual exploratory wells, wells drilled from existing platforms and wells drilled and connected to an existing separation/treatment facility without substantial construction of additional infrastructure are not new sources.

As discussed above, the lack of negative economic impacts from allowing SBF discharge leads EPA to the conclusion that the effluent guidelines are economically achievable for both existing and new sources. Additionally, on a per-well basis, NSPS is expected to result in greater cost savings than BAT because new platforms do not require the retrofit costs to enable the improved solids control equipment to be placed on existing platforms. Because the preferred NSPS option results in cost savings and those cost savings are greater than those realized by existing operations, there are no barriers to entry. In fact, the rule might act as an small incentive to new source development (see discussion in Section X.C.4).

E. Cost-Benefit Analysis

Pursuant to E.O. 12866, EPA chose to quantitatively and qualitatively compares the costs and benefits of the preferred discharge option. The total annual cost savings of the rule in pretax dollars are $7.2 million, including the costs to both existing and new operations. Benefits also include 72.03 tons of air emissions reduced from both existing and new sources per year (including nitrogen oxides and sulfur dioxides, and other ozone precursors). These reductions arise because operators are encouraged to use SBFs and discharge cuttings rather than use OBFs and transport wastes to shore for disposal or grind and inject cuttings). SBF use also results in an energy savings of 2,302 barrels of oil equivalent per year when the cuttings are no longer hauled to shore for disposal or ground up for injection. An additional 14.1 million pounds per year of pollutants, however, would be discharged to surface waters annually, but due to pollution prevention technology, this discharge prevents 34 million pounds of wastes from being land disposed or injected each year. See Table X–3 for a summary of the costs and benefits of BAT and NSPS requirements under the discharge option.

Under the zero discharge option, costs would be $8.6 million, and 178 million pounds per year of pollutants would no longer be discharged, but an additional 34 million pounds of waste would be land disposed or injected each year. Furthermore, compared to current practice, 380 tons of air emissions would be generated annually, and energy consumption would increase by 27,000 barrels of oil equivalent per year. See Table X–3 for a summary of the costs and benefits of BAT and NSPS requirements under the zero discharge option. Note that these costs and benefits are incremental to the current baseline, not incremental to the discharge option, which is how many of these numbers are presented in the text in Section VII.

TABLE X–3.—SUMMARY OF COSTS AND BENEFITS UNDER THE DISCHARGE OPTION AND ZERO DISCHARGE OPTION

Cost or benefit category	Discharge option			Zero discharge option		
	BAT	NSPS	Total	BAT	NSPS	Total
Cost ($million) [1]	−$6.6	−$0.6	−$7.2	+$7.0	+$1.6	+$8.6
Energy (barrels of oil equivalent) [2]	−2,613	+311	−2,302	+24,125	+2,932	+27,057
Solid Waste (MM lbs) [3]	−34	0	−34	+165	+13	+178
Air Emissions (tons per year) [2]	−73.3	+1.28	−72.02	+338.55	+41	+379.55
Water Pollutants (MM lb/yr) [4]	+15.8	−1.6	+14.1	−159.1	−18.3	−177.4

Note: minus signs indicate a cost savings or benefit; plus signs indicate a cost or an impact.
[1] See Table X–1.
[2] See Tables VII–1 and VII–2.
[3] See Section VII.E.
[4] See Tables IX–4 and IX–5.

F. Small Business Analysis

Pursuant to the requirements of the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), EPA performed a small business analysis to determine if an Initial Regulatory Flexibility Analysis (IRFA) must be performed. The analysis undertaken here is used to determine if the rule would have a significant impact on a substantial number of small entities. This section discusses the number of small entities estimated to be affected by the rule and analyzes the potential magnitude of impact on these entities. Under the preferred option, no wells are expected to incur costs, thus no firms are affected in any negative way by the proposed effluent guidelines. These results will be discussed as they apply to the RFA and SBREFA requirements in Section XI.B of today's notice.

Although well drilling and platform operations have not changed significantly in the intervening years since the offshore rule was promulgated, many of the operators have changed. When the offshore rule was promulgated, EPA believed no small firms were likely to be affected by that rule. As the offshore region of the Gulf, in particular, has matured, smaller firms have begun drilling and producing. In EPA's experience (see Economic Impact Analysis for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821/R95–13), as an oil and gas region matures the majors can no longer earn returns meeting their requirements and sell their operations to other firms, usually smaller independents who have lower overheads, more limited access to capital, and fewer means and opportunity to take on higher risk or overseas activities. Because of this change in the size of firms operating in the offshore region, EPA re-evaluated the earlier conclusion about small firms operating in offshore regions and estimated impacts on small business.

The first step of this analysis was to separate the actively drilling firms into small and large firms. The Small Business Administration (SBA) characterizes an oil and gas production operator as small if it employs fewer than 500 employees and an oil and gas services provider as small if it generates less than $5 million per year in revenues. Because many small firms in this industry are partly or wholly owned by larger firms, EPA traced ownership of

small firms to determine whether their parent companies also were small businesses. Generally, EPA characterized a firm at the higher level of organization if it was majority owned by the larger entity (except in a few instances when the subsidiary was a large business and publicly available information was available for that level of the corporation; e.g., Vastar, which is about 80 percent owned by ARCO). This approach is consistent with SBA's definition of affiliation. Small firms that are affiliated (e.g., 51 percent owned) by firms not defined as small by SBA's standards (13 CFR Part 121) are not considered small for the purposes of regulatory flexibility analysis.

EPA determined that a total of 42 small firms might be subject to the requirements of the SBF Effluent Guidelines. These 42 small firms, although meeting SBA's definition of small for this industry, are generally larger than firms typically considered small in other industries. The median assets for this group (among publicly held firms) is about $263 million, median equity is about $127 million, median revenues are about $16 million, and median net income is about $2.8 million. Median return on assets is about 1.5 percent, median return on equity is about 3.3 percent, and net income to revenues (net profit margin) is about 6.8 percent. Although returns are not as strong as those associated with the affected industry as a whole, profit margin is generally about the same as typical margins for the affected industry, regardless of size of firm. Revenues range from a high of $383 million to a low of $160,000. Actual or Dun & Bradstreet estimated revenue figures were identified for nearly all small firms, although other financial information was available for only about half of the small firms. Employment at these small firms ranges from a high of 400 to a low of 2. Median employment is approximately 38 persons.

As noted above, under the discharge option, no wells are expected to incur costs, thus no firms would be affected in any negative way by the proposed effluent guidelines.

EPA also looked at the impacts of the zero-discharge option, or other options that would incur costs, in which case those small firms using SBFs potentially would incur compliance costs. As in the analysis of all firms discussed above in Section X.C.3, EPA has determined that the likeliest users of SBF in shallow water locations would be the same operators who use SBF in deep water operations. Thus the firms with both deep water and shallow water operations would be the potentially affected firms. Only one firm meets this definition as well as the SBA definition of small entity and thus would be an affected small firm under the zero discharge option. EPA finds that one firm is not a substantial number of small entities. Further, EPA estimated costs for zero discharge on this firm and compared these costs to the firm's revenues. The costs would be less than one percent of revenues under the zero discharge option, and EPA finds this is not a significant impact.

G. Cost-Effectiveness Analysis

Cost-effectiveness analysis evaluates the relative efficiency of options in removing toxic pollutants and nonconventional pollutants. Cost-effectiveness results are expressed in terms of the incremental and average costs per pound-equivalent removed. A pound equivalent is a measure that addresses differences in the toxicity of pollutants removed. Total pound-equivalents are derived by taking the number of pounds of a pollutant removed and multiplying this number by a toxic weighting factor. EPA calculates the toxic weighting factor using ambient water quality criteria and toxicity values. The toxic weighting factors are then standardized by relating them to a particular pollutant, in this case copper.

For the purpose of evaluating most effluent guidelines, EPA's standard procedure is to rank the options considered for each subcategory in order of increasing pounds-equivalent removed. The Agency calculates incremental cost-effectiveness as the ratio of the incremental annual costs to the incremental pounds-equivalent removed under each option, compared to the previous (less effective) option. Average cost-effectiveness is calculated for each option as a ratio of total costs to total pounds-equivalent removed.

While cost-effectiveness results are usually reported in the Notice of Proposed Rule for effluent guidelines, those results are not presented in today's notice because there are no incremental costs attributed to the proposed option, and EPA did not calculate a cost-effectiveness ratio for the proposed option. In the rulemaking record, EPA presents a more detailed discussion of cost-effectiveness analysis and reports results for the zero discharge option.

XI. Related Acts of Congress, Executive Orders, and Agency Initiatives

A. Executive Order 12866: OMB Review

Under Executive Order 12866, [58 Federal Register 51,735 (October 4, 1993)] the Agency must determine whether the regulatory action is ''significant'' and therefore subject to OMB review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this proposed rule is not a ''significant regulatory action,'' and is therefore not subject to OMB review.

B. Regulatory Flexibility Act and the Small Business Regulatory Enforcement Fairness Act

Under the Regulatory Flexibility Act (RFA), 5 U.S.C. 601 *et seq.* as amended by the Small Business Regulatory Enforcement Fairness Act, EPA generally is required to conduct an initial regulatory flexibility analysis (IRFA) describing the impact of the proposed rule on small entities as a part of rulemaking. However, under section 605(b) of the RFA, if the Administrator certifies that the rule will not have a significant economic impact on a substantial number of small entities, EPA has prepared an analysis equivalent to an IRFA.

Using the U.S. Small Business Administration's definition for small business for this industry (i.e., firms with fewer than 500 employees for oil and gas production operators and less than $5 million per year in revenues for oil and gas services providers), EPA estimates the proposed rule would apply to 42 small firms. As explained in Sections IX and X of this notice, none of these small firms are expected to incur any costs as a result of this rule. Thus, EPA projects no adverse economic impacts to the small firms. To the contrary, if these firms use SBF, they are likely to experience cost savings.

Based on the assessment of the economic impact of regulatory options being considered for the proposed rule

as discussed in Section X, the Administrator therefore certifies that the proposed rule would not have a significant economic impact on a substantial number of small entities. Therefore, the Agency did not prepare an IRFA.

While EPA has so certified today's proposed rule, the Agency nonetheless prepared a small business analysis, incorporating many of the features of the assessment required by the RFA. The small business analysis for the proposed rule is summarized in Section X.F of this notice.

C. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under Section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 do not apply when they are inconsistent with applicable law. Moreover, Section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Today's proposed rule contains no Federal mandates (under the regulatory provisions of Title II of the UMRA) for State, local, or tribal governments or the private sector. The rule would impose no enforceable duty on any State, local, or tribal governments or require any expenditure of $100 million or more to the private sector. Thus today's proposed rule is not subject to the requirements of Sections 202 and 205 of the UMRA.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under Section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant intergovernmental mandates, and informing, educating, and advising small governments on compliance with regulatory requirements. As this rule has no effect on small governments, this rule would not significantly or uniquely affect small governments and Section 203 of the UMRA does not apply.

D. Executive Order 12875: Enhancing Intergovernmental Partnerships

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 12875 requires EPA to provide to the Office of Management and Budget a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments ''to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates.''

Today's proposed rule would not create a mandate on State, local or tribal governments. The proposed rule would not impose any enforceable duties on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 do not apply to this proposed rule.

E. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires EPA to provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. As previously discussed this proposed rule does not impose any mandates on Tribal governments. Further, the only Indian communities in proximity to the activities addressed by this proposed rule are in Cook Inlet, Alaska. EPA does not project, however, that these communities would be affected by this rule. EPA projects that on average, 8 wells will be drilled in Cook Inlet annually. EPA further projects that of these 8 wells, one well would be drilled with OBF in the absence of this rule, and this one OBF well would convert to using SBF with today's proposed discharge option. EPA concludes that this effect of one well annually converting from OBF to SBF is minor, and would not significantly or uniquely affect the communities of Indian tribal governments. Further, today's proposed rule would not impose substantial direct compliance costs on such communities. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

F. Paperwork Reduction Act

The proposed synthetic-based drilling fluids effluent guidelines contain no new information collection activities and, therefore, no information collection request will be submitted to OMB for review under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq.

G. National Technology Transfer and Advancement Act

Under section 12(d) of the National Technology Transfer and Advancement Act (NTTAA), the Agency is required to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices, etc.) that are

developed or adopted by voluntary consensus standards bodies. Where available and potentially applicable voluntary consensus standards are not used by EPA, the Act requires the Agency to provide Congress, through the Office of Management and Budget (OMB), an explanation of the reasons for not using such standards. The following discussion summarizes EPA's response to the requirements of the NTTAA.

EPA performed a search of the technical literature to identify any applicable analytical test methods from industry, academia, voluntary consensus standard bodies and other parties that could be used to measure the analytes in today's proposed rulemaking. EPA's search revealed that there are consensus standards for many of the analytes specified in the tables at 40 CFR Part 136.3. Even prior to enactment of the NTTAA, EPA has traditionally included any applicable consensus test methods in its regulations. Consistent with the requirements of the CWA, those applicable consensus test methods are incorporated by reference in the tables at 40 CFR Part 136.3. The consensus test methods in these tables include American Society for Testing and Materials (ASTM) and Standard Methods.

Today's proposal would require dischargers to monitor for five additional parameters with up to six additional methods: polynuclear aromatic hydrocarbon (PAH) content of the base fluid, biodegradation rate of the base fluid, sediment toxicity, formation (crude) oil contamination in drilling fluid (two methods), and quantity of drilling fluid discharged with cuttings. EPA plans to approve use of test methods for these parameters in conjunction with the promulgation of the final rule. In addition, EPA is considering a requirement for bioaccumulation of the base fluid. EPA has identified applicable consensus methods for two parameters, ASTM Method E–1367–92 for sediment toxicity and American Petroleum Institute Retort Method (Recommended Practice 13B–2) for quantity of drilling fluid discharged with cuttings. For PAH content of the base fluid, EPA is proposing the use of EPA Method 1654A which was validated with assistance from a voluntary consensus standards body. With stakeholder support in data gathering activities, EPA intends to develop or encourage voluntary consensus standards bodies to develop appropriate methods for oil contamination in drilling fluid and biodegradation rate.

H. Executive Order 13045: Children's Health Protection

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health risk or safety risk that the Agency has reason to believe may have a disproportionate effect on children. If a regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This proposed rule is not subject to E.O. 13045, ''Protection of Children from Environmental Health Risks and Safety Risks'' because this is not an ''economically significant'' regulatory action as defined by E.O. 12866. Further, EPA interprets E.O. 13045 as applying only to those regulatory activities that are based on health or safety risks, such that the analysis required under Section 5–501 of the Order has the potential to influence the regulation. Thus, this rule is not subject to E.O. 13045 because it is based on technology performance and not on health or safety risks.

XII. Regulatory Implementation

A. Analytical Methods

Section 304(h) of the Clean Water Act directs EPA to promulgate guidelines establishing test procedures for the analysis of pollutants. These test procedures (methods) are used to determine the presence and concentration of pollutants in wastewater, and are used for compliance monitoring and for filing applications for the NPDES program under 40 CFR Parts 122.21, 122.41, 122.44 and 123.25, and for the implementation of the pretreatment standards under 40 CFR Part 403.10 and 403.12. To date, EPA has promulgated methods for conventional pollutants, toxic pollutants, and for some nonconventional pollutants. The five conventional pollutants are defined at 40 CFR Part 401.16. Table I–B at 40 CFR Part 136 lists the analytical methods approved for these pollutants. The 65 toxic metals and organic pollutants and classes of pollutants are defined at 40 CFR Part 401.15. From the list of 65 classes of toxic pollutants EPA identified a list of 126 ''Priority Pollutants.'' This list of Priority Pollutants is shown, for example, at 40 CFR Part 423, Appendix A. The list includes non-pesticide organic pollutants, metal pollutants, cyanide, asbestos, and pesticide pollutants.

Currently approved methods for metals and cyanide are included in the table of approved inorganic test procedures at 40 CFR Part 136.3, Table I–B. Table I–C at 40 CFR Part 136.3 lists approved methods for measurement of non-pesticide organic pollutants, and Table I–D lists approved methods for the toxic pesticide pollutants and for other pesticide pollutants. Dischargers must use the test methods promulgated at 40 CFR Part 136.3 or incorporated by reference in the tables, when available, to monitor pollutant discharges from the oil and gas industry, unless specified otherwise in part 435 or by the permitting authority.

As part this rulemaking, EPA is proposing to allow use of analytical methods for determining additional parameters that are specific to characterizing SBFs and other non-aqueous drilling fluids. These additional parameters include polynuclear aromatic hydrocarbon (PAH) content of the base fluid, biodegradation rate of the base fluid, sediment toxicity, formation (crude) oil contamination in drilling fluid, and quantity of drilling fluid discharged with cuttings.

EPA worked with stakeholders to identify methods for determining these parameters. For PAH content, EPA is proposing the use of EPA Method 1654A. For biodegradation rate, EPA is proposing the use a solid phase test developed in the United Kingdom. For sediment toxicity, EPA is proposing the use of American Society for Testing and Material (ASTM) Method E–1367–92 supplemented with sediment preparation procedures. For formation (crude) oil contamination in drilling fluid, EPA is proposing the use of two methods, a reverse phase fluorescence test and a gas chromatography/mass spectrometry (GC/MS) test. The reverse phase fluorescence test is a screening method that provides a quick and inexpensive determination of oil contamination for use on offshore well drilling sites, while the GC/MS test provides a definitive identification and quantitation of oil contamination for baseline analysis. For determining the quantity of drilling fluid discharged with cuttings, EPA is proposing the use of the American Petroleum Institute Retort Method (Recommended Pratice 13B–2). EPA Method 1654A and ASTM E–1367–92 are incorporated by reference into 40 CFR Part 435 because they are published methods that are widely available to the public. Supplemental sediment preparation procedures for ASTM E–1367–92 are

provided in Appendix 3 to 40 CFR Part 435. The text of the four other proposed methods are provided in Appendices 4–7 to 40 CFR Part 435. Subpart A.

EPA currently is conducting additional development and validation of the proposed methods and researching the possible inclusion of additional or alternate methods. EPA intends to publish a notice of data availability to solicit comments on the selected methods prior to publication of a final rule.

On March 28, 1997, EPA proposed a means to streamline the method development and approval process (62 FR 14975) and on October 6, 1997, EPA published a notice of intent to implement a performance-based measurement system (PBMS) in all of its programs to the extent feasible (62 FR 52098). The Agency is currently determining the specific steps necessary to implement PBMS in all of its regulatory programs and has approved a plan for implementation of PBMS in the water programs. Under PBMS, regulated entities will be able to modify methods without prior approval and will be able to use new methods without prior EPA approval provided they notify the regulatory authority to which the data will be reported. EPA expects a final rule implementing PBMS in the water programs by the end of calendar year 1998. When the final rule takes effect, regulated entities will be able to select methods for monitoring other than those approved at 40 CFR Parts 136 and 435 provided that certain validation requirements are met. Many of the details were provided at proposal (62 FR 14975) and will be finalized in the final PBMS rule.

B. Diesel Prohibition for SBF-Cuttings

Under today's proposed rule, drill cuttings that have come in contact with SBF containing any amount of diesel oil are prohibited from discharge. A certain amount of formation oil contamination, however, would be allowed under this proposed rule. Since diesel oil and formation oil have many components in common, it would be nearly impossible to analytically determine the absence, or presence, of diesel when SBFs are contaminated with allowable levels of formation oil. For this reason, operators are to certify that the SBFs in use are free of diesel oil if the SBF-cuttings are to be allowed for discharge.

C. Monitoring of Stock Base Fluid

Under today's proposed rule, SBF-cuttings would be allowed for discharge only if the base fluids used to formulate the SBFs meet requirements in terms of PAH content, sediment toxicity, and biodegradation rate. The PAH content should be determined on a batchwise basis, or production lot basis. This is due to the fact that, at least for some of the base fluid manufacturing processes, PAH contamination may occur. Also, the analytical method is rapid and relatively inexpensive. The sediment toxicity and biodegradation rate should be determined once per year per base fluid trade name. These are parameters that EPA does not expect to change on a batch to batch or lot to lot basis. Also, the methods used to determine the parameters of sediment toxicity and biodegradation are longer term and more elaborate tests to conduct.

D. Upset and Bypass Provisions

A recurring issue of concern has been whether industry guidelines should include provisions authorizing noncompliance with effluent limitations during periods of ''upsets'' or ''bypasses''. The reader is referred to the Offshore Guidelines (58 FR 12501) for a discussion on upset and bypass provisions.

E. Variances and Modifications

Once this regulation is in effect, the effluent limitations must be applied in all NPDES permits thereafter issued to discharges covered under this effluent limitations guideline subcategory. Under the CWA certain variances from BAT and BCT limitations are provided for. A section 301(n) (Fundamentally Different Factors) variance is applicable to the BAT and BCT and pretreatment limits in this rule. The reader is referred to the Offshore Guidelines (58 FR 12502) for a discussion on the applicability of variances.

F. Best Management Practices

Sections 304(e) and 402 (a) of the Act authorizes the Administrator to prescribe ''best management practices'' (BMPs). EPA may develop BMPs that apply to all industrial sites or to a designated industrial category and may offer guidance to permit authorities in establishing management practices required by unique circumstances at a given plant.

EPA is considering the use of BMPs as part of the final rule to address the requirement of zero discharge of SBF not associated with drill cuttings. EPA understands that there are occasional instances when spills of SBF occur, and that the location and perhaps even the timing of these spills is predictable. EPA solicites comments from industry indicating the types of BMPs that would minimize or prevent SBF spills. EPA solicites comments from all stakeholders whether the zero discharge requirement should be controlled in these guidelines using BMPs or other means, such as a specific limitation.

G. Sediment Toxicity and Biodegradation Comparative Limitations

In lieu of a numerical limitation, between the time of today's proposal and the final rule, EPA recommends that if SBFs based on fluids other than internal olefins and vegetable esters are to be discharged with drill cuttings, data showing the toxicity of the base fluid should be presented with data, generated in the same series of tests, showing the toxicity of the internal olefin and the vegetable ester as standards. Base fluids determined to have LC_{50} values greater than or equal to the LC_{50} value determined for C_{16}–C_{18} internal olefins, in the same series of test, would be acceptable for discharge.

For biodegradation testing also, in the interim period between today's proposed rule and the final rule, EPA recommends that if SBFs based on fluids other than internal olefins and vegetable esters are to be discharged with drill cuttings, data showing the biodegradation of the base fluid should be presented with data, generated in the same series of tests, showing the biodegradation of the internal olefin as a standard.

EPA prefers this approach for the sediment and biodegradation limitations rather than set numeric limitations at this time because of the small amount of data available to EPA upon which to base these numerical limits. EPA sees this as an interim solution to provide a limitation based on the performance of available technologies.

XIII. Solicitation of Data and Comments

EPA encourages public participation in this rulemaking. The Agency asks that comments address any perceived deficiencies in the record supporting this proposal and that suggested revisions or corrections be supported by data. In addition, EPA requests comments on the various ways of handling the applicability of these proposed guidelines, as this relates to the definitions for water-based drilling fluids and non-aqueous drilling fluids.

The Agency invites all parties to coordinate their data collection activities with EPA to facilitate mutually beneficial and cost-effective data submissions. Please refer to the ''For Further Information'' section at the beginning of this preamble for technical contacts at EPA.

To ensure that EPA can properly respond to comments, the Agency prefers that commenters cite, where

possible, the paragraph(s) or sections in the notice or supporting documents to which each comment refers. Please submit an original and two copies of your comments and enclosures (including references).

Commenters who want EPA to acknowledge receipt of their comments should enclose a self-addressed, stamped envelope. No facsimiles (faxes) will be accepted. Comments and data will also be accepted on disks in WordPerfect format or ASCII file format.

Comments may also be filed electronically to ''daly.joseph@epa.gov.'' Electronic comments must be submitted as an ASCII or Wordperfect file avoiding the use of special characters and any form of encryption. Electronic comments must be identified by the docket number W–98–26 and may be filed online at many Federal Depository Libraries. No confidential business information (CBI) should be sent via e-mail.

List of Subjects in 40 CFR Part 435

Environmental protection, Non-aqueous drilling fluids, Oil and gas extraction, Synthetic based drilling fluids, Waste treatment and disposal, Water non-dispersible drilling fluids, Water pollution control, Pollution prevention.

Dated: December 29, 1998

Carol M. Browner,

Administrator.

Appendix A To The Preamble—Abbreviations, Acronyms, and Other Terms Used in This Notice

Act—Clean Water Act
Agency—U.S. Environmental Protection Agency
API—American Petroleum Institute
ASTM—American Society of Testing and Materials
BADCT—The best available demonstrated control technology, for new sources under section 306 of the Clean Water Act
BAT—The best available technology economically achievable, under section 304(b)(2)(B) of the Clean Water Act
bbl—barrel, 42 U.S. gallons
BCT—Best conventional pollutant control technology under section 304(b)(4)(B)
BMP—Best management practices under section 304(e) of the Clean Water Act
BOD—Biochemical oxygen demand
BOE—Barrels of oil equivalent
BPJ—Best Professional Judgement
BPT—Best practicable control technology currently available, under section 304(b)(1) of the Clean Water Act
CFR—Code of Federal Regulations
Clean Water Act—Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 *et seq.*)
Conventional pollutants—Constituents of wastewater as determined by section 304(a)(4) of the Act, including, but no limited to, pollutants classified as biochemical oxygen demanding, suspended solids, oil and grease, fecal coliform, and pH
CWA—Clean Water Act
Direct discharger—A facility which discharges or may discharge pollutants to waters of the United States
D&B—Dun & Bradstreet
DOE—Department of Energy
DWD—Deep-water development model well
DWE—Deep-water exploratory model well
EPA—U.S. Environmental Protection Agency
FR—Federal Register
GC—Gas Chromatography
GC/FID—Gas Chromatography with Flame Ionization Detection
GC/MS—Gas Chromatography with Mass Spectroscopy Detection
GOM—Gulf of Mexico
Indirect discharger—A facility that introduces wastewater into a publicly owned treatment works
IRFA—Initial Regulatory Flexibility Analysis
LC_{50} (or LC50)—The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay
mg/l—milligrams per liter MMS—Department of Interior Minerals Management Service Nonconventional pollutants—Pollutants that have not been designated as either conventional pollutants or priority pollutants
NOIA—National Ocean Industries Association
NOW—Nonhazardous Oilfield Waste
NPDES—The National Pollutant Discharge Elimination System
NRDC—Natural Resources Defense Council, Incorporated
NSPS—New source performance standards under section 306 of the Clean Water Act
NTTAA—National Technology Transfer and Advancement Act
OBF—Oil-Based Drilling Fluid
OCS—Offshore Continental Shelf
OMB—Office of Management and Budget
PAH—Polynuclear Aromatic Hydrocarbon
PBMS—Performance Based Measurement System
POTW—Publicly Owned Treatment Works
ppm—parts per million
PPA—Pollution Prevention Act of 1990
Priority pollutants—The 65 pollutants and classes of pollutants declared toxic under section 307(a) of the Clean Water Act
PSES—Pretreatment standards for existing sources of indirect discharges, under section 307(b) of the Act
PSNS—Pretreatment standards for new sources of indirect discharges, under sections 307(b) and (c) of the Act
RFA—Regulatory Flexibility Act
RPE—Reverse Phase Extraction
SBA—Small Business Administration
SBF—Synthetic Based Drilling Fluid
SBF Development Document—Development Document for Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category
SBF Economic Analysis—Economic Analysis of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category
SBF Environmental Assessment—Environmental Assessment of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category
SBREFA—Small Business Regulatory Enforcement Fairness Act
SEC—Security and Exchange Commission
SIC—Standard Industrial Classification
SPP—Suspended particulate phase
SWD—Shallow-water development model well
SWE—Shallow-water exploratory model well
TSS—Total Suspended Solids
UMRA—Unfunded Mandates Reform Act
U.S.C.—United States Code
WBF—Water-Based Drilling Fluid

For the reasons set forth in the preamble, 40 CFR Part 435 is proposed to be amended as follows:

PART 435—OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

1. The authority citation for Part 435 is revised to read as follows:

Authority: (33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342 and 1361).

Subpart A—Offshore Subcategory

2. Section 435.11 is revised to read as follows:

§ 435.11 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided in this section, the general definitions, abbreviations and methods of analysis set forth in 40 CFR part 401 shall apply to this subpart.

(b) The term *average of daily values for 30 consecutive days* shall be the average of the daily values obtained during any 30 consecutive day period.

(c) The term *base fluid retained on cuttings* shall refer to American Petroleum Institute Recommended Practice 13B–2 supplemented with the specifications, sampling methods, and averaging of the retention values provided in appendix 7 of 40 CFR part 435, subpart A.

(d) The term *biodegradation rate* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to the test procedure presented in appendix 4 of 40 CFR part 435, subpart A.

(e) The term *daily values* as applied to produced water effluent limitations and NSPS shall refer to the daily measurements used to assess compliance with the maximum for any one day.

(f) The term *deck drainage* shall refer to any waste resulting from deck washings, spillage, rainwater, and

runoff from gutters and drains including drip pans and work areas within facilities subject to this subpart.

(g) The term *percent degraded at 120 days* shall refer to the concentration (milligrams/kilogram dry sediment) of the base fluid in sediment relative to the intial concentration of base fluid in sediment at the start of the test on day zero.

(h) The term *percent stock base fluid degraded at 120 days minus percent* C_{16}-C_{18} *internal olefin degraded at 120 days shall not be less than zero* shall mean that the percent base fluid degraded at 120 days of any single sample of base fluid shall not be less than the percent C_{16}-C_{18} internal olefin degraded at 120 days as a control standard.

(i) The term *development facility* shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling of productive wells.

(j) The term *diesel oil* shall refer to the grade of distillate fuel oil, as specified in the American Society for Testing and Materials Standard Specification for Diesel Fuel Oils D975–91, that is typically used as the continuous phase in conventional oil-based drilling fluids. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR Part 51. Copies may be obtained from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103. Copies may be inspected at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. A copy may also be inspected at EPA's Water Docket, 401 M Street SW., Washington, DC 20460.

(k) The term *domestic waste* shall refer to materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to this subpart.

(l) The term *drill cuttings* shall refer to the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid.

(m) The term *drilling fluid* refers to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. Classes of drilling fluids are:

(1) A water-based drilling fluid has water or a water miscible fluid as the continuous phase and the suspending medium for solids, whether or not oil is present.

(2) A non-aqueous drilling fluid is one in which the continuous phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhanced mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

(3) An oil-based drilling fluid has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase. Oil-based drilling fluids are a subset of non-aqueous drilling fluids.

(4) An enhanced mineral oil-based drilling fluid has an enhanced mineral oil as its continuous phase with water as the dispersed phase. Enhanced mineral oil-based drilling fluids are a subset of non-aqueous drilling fluids.

(5) A synthetic-based drilling fluid has a synthetic material as its continuous phase with water as the dispersed phase. Synthetic-based drilling fluids are a subset of non-aqueous drilling fluids.

(n) The term *enhanced mineral oil* as applied to enhanced mineral oil-based drilling fluid means a petroleum distillate which has been highly purified and is distinguished from diesel oil and conventional mineral oil in having a lower polycyclic aromatic hydrocarbon (PAH) content. Typically, conventional mineral oils have a PAH content on the order of 0.35 weight percent expressed as phenanthrene, whereas enhanced mineral oils typically have a PAH content of 0.001 or lower weight percent PAH expressed as phenanthrene.

(o) The term *exploratory facility* shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

(p) The term *no discharge of formation oil* shall mean that cuttings contaminated with non-aqueous drilling fluids (NAFs) may not be discharged if the NAFs contain formation oil, as determined by the GC/MS baseline method as defined in appendix 5 to 40 CFR part 435, subpart A, to be applied before NAFs are shipped offshore for use, or the RPE method as defined in appendix 6 to 40 CFR part 435, subpart A, to be applied at the point of discharge. At the discretion of the permittee, detection of formation oil by the RPE method may be assured by the GC/MS method, and the results of the GC/MS method shall supercede those of the RPE method.

(q) The term *maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the maximum concentration allowed as measured in any single sample of the barite for determination of cadmium and mercury content, or as measured in any single sample of base fluid for determination of PAH content.

(r) The term *maximum weighted average for well* for BAT effluent limitations and NSPS for base fluid retained on cuttings shall mean the weighted average base fluid retention as determined by API RP 13B–2, using the methods and averaging calculations presented in appendix 7 of 40 CFR part 435, subpart A.

(s) The term *maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS for oil and grease in produced water shall mean the maximum concentration allowed as measured by the average of four grab samples collected over a 24-hour period that are analyzed separately. Alternatively, for BAT and NSPS the maximum concentration allowed may be determined on the basis of physical composition of the four grab samples prior to a single analysis.

(t) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the minimum 96-hour LC_{50} value allowed as measured in any single sample of the discharged waste stream. The term *minimum* as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes shall mean the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(u) The term *M9IM* shall mean those offshore facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(v) The term *M10* shall mean those offshore facilities continuously manned by ten (10) or more persons.

(w) The term *new source* means any facility or activity of this subcategory that meets the definition of ''new source'' under 40 CFR 122.2 and meets the criteria for determination of new sources under 40 CFR 122.29(b) applied consistently with all of the following definitions:

(1) The term *water area* as used in the term ''site'' in 40 CFR 122.29 and 122.2 shall mean the water area and ocean floor beneath any exploratory, development, or production facility where such facility is conducting its exploratory, development or production activities.

(2) The term *significant site preparation work* as used in 40 CFR 122.29 shall mean the process of surveying, clearing or preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site. ''New Source'' does *not* include facilities covered by an existing NPDES

permit immediately prior to the effective date of these guidelines pending EPA issuance of a new source NPDES permit.

(x) The term *no discharge of free oil* shall mean that waste streams may not be discharged that contain free oil as evidenced by the monitoring method specified for that particular stream, e.g., deck drainage or miscellaneous discharges cannot be discharged when they would cause a film or sheen upon or discoloration of the surface of the receiving water; drilling fluids or cuttings may not be discharged when they fail the static sheen test defined in appendix 1 to 40 CFR part 435, subpart A.

(y) The term *produced sand* shall refer to slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.

(z) The term *produced water* shall refer to the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

(aa) The term *production facility* shall mean any fixed or mobile structure subject to this subpart that is either engaged in well completion or used for active recovery of hydrocarbons from producing formations.

(bb) The term *sanitary waste* shall refer to human body waste discharged from toilets and urinals located within facilities subject to this subpart.

(cc) The term *sediment toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to ASTM E1367–92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods (Available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in appendix 3 of 40 CFR part 435, subpart A.

(dd) The term *static sheen test* shall refer to the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the static sheen test is presented in appendix 1 to 40 CFR part 435, subpart A.

(ee) The term *synthetic material* as applied to synthetic-based drilling fluid means material produced by the reaction of specific purified chemical feedstock, as opposed to the traditional base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes. Physical separation processes include fractionation and distillation and/or minor chemical reactions such as cracking and hydro processing. Since they are synthesized by the reaction of purified compounds, synthetic materials suitable for use in drilling fluids are typically free of polycyclic aromatic hydrocarbons (PAH's) but are sometimes found to contain levels of PAH up to 0.001 weight percent PAH expressed as phenanthrene. Poly(alpha olefins) and vegetable esters are two examples of synthetic materials suitable for use by the oil and gas extraction industry in formulating drilling fluids. Poly(alpha olefins) are synthesized from the polymerization (dimerization, trimerization, tetramerization, and higher oligomerization) of purified straight-chain hydrocarbons such as C_6-C_{14} alpha olefins. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. The mention of these two branches of synthetic fluid base materials is to provide examples, and is not meant to exclude other synthetic materials that are either in current use or may be used in the future. A synthetic-based drilling fluid may include a combination of synthetic materials.

(ff) The term *SPP toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to the bioassay test procedure presented in appendix 2 of 40 CFR part 435, subpart A.

(gg) The term *well completion fluids* shall refer to salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.

(hh) The term *well treatment fluids* shall refer to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(ii) The term *workover fluids* shall refer to salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(jj) The term *10-day* LC_{50} shall refer to the concentration (milligrams/kilogram dry sediment) of the base fluid in sediment that is lethal to 50 percent of the test organisms exposed to that concentration of the base fluids after 10-days of constant exposure.

(kk) The term *10-day* LC_{50} *of stock base fluid minus 10-day* LC_{50} *of* C_{16}-C_{18} *internal olefin shall not be less than zero* shall mean that the 10-day LC_{50} of any single sample of the base fluid shall not be less than the LC_{50} of C_{16}-C_{18} internal olefin as a control standard.

(ll) The term *96-hour* LC_{50} shall refer to the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

3. In § 435.12 the table is amended by removing the entries ''Drilling muds'' and ''Drill cuttings'' and by adding new entries (after ''Deck drainage'') for ''Water based'' and ''Non-aqueous'' to read as follows:

§ 435.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

* * * * *

BPT EFFLUENT LIMITATIONS—OIL AND GREASE

[In milligrams per liter]

Pollutant parameter waste source	Maximum for any 1 day	Average of values for 30 consecutive days shall not exceed	Residual chlorine minimum for any 1 day
* * *	*	* *	*
Water-based:			
Drilling fluids	(1)	(1)	NA
Drill cuttings	(1)	(1)	NA

BPT EFFLUENT LIMITATIONS—OIL AND GREASE—Continued

[In milligrams per liter]

Pollutant parameter waste source	Maximum for any 1 day	Average of values for 30 consecutive days shall not exceed	Residual chlorine minimum for any 1 day
Non-aqueous:			
Drilling fluids	No discharge	No discharge	NA
Drill cuttings	(1)	(1)	NA
* * * * * * *			

[1] No discharge of free oil.

* * * * *

4. In § 435.13 the table is amended by revising entry B under the entry for ''Drilling fluids and drill cuttings'' and by revising footnote 2 and adding footnotes 5–9 to read as follows:

§ 435.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

* * * * *

BAT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter	BAT effluent limitation
* * * * * * *		
Drilling fluids and drill cuttings		
* * * * * * *		
(B) For facilities located beyond 3 miles from shore		
Water-based drilling fluids and drill cuttings	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP shall be 3% by volume [2].
	Free oil	No discharge [3].
	Diesel oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids		No discharge.
Cuttings associated with non-aqueous drilling fluids		
Stock Limitations	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Polynuclear Aromatic Hydrocarbons (PAH)	Maximum 10 ppm wt. PAH based on phenanthrene/wt. of stock base fluid [5].
	Sediment Toxicity	10-day LC_{50} of stock base fluid minus 10-day LC_{50} of C_{16}-C_{18} internal olefin shall not be less than zero [6].
	Biodegradation Rate	Percent stock base fluid degraded at 120 days minus percent C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero [7].
Discharge Limitations	Diesel oil	No discharge.
	Formation Oil	No discharge [8].
	Base fluid retained on cuttings	Maximum weighted average for well shall be 10.2 percent [9].
* * * * * * *		

* * * * * * *

[2] As determined by the suspended particulate phase toxicity test (Appendix 2).

[3] As determined by the static sheen test (Appendix 1).

* * * * * * *

[5] As determined by EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector in Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA–821–R–92–008 [Incorporated by reference and available from National Technical Information Service (NTIS) (703/605–6000)].

[6] As determined by ASTM E1367–92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods (Incorporated by reference and available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in Appendix 3.

[7] As determined by the biodegradation test (Appendix 4).

[8] As determined by the GC/MS baseline and assurance method (Appendix 5), and by the RPE method applied to drilling fluid removed from cuttings at primary shale shakers (Appendix 6).

[9] Maximum permissible retention of base fluid on wet cuttings averaged over drill intervals using non-aqueous drilling fluids as determined by retort method (Appendix 7).

5. In § 435.14 the table is amended by revising entry B under the entry for ''Drilling fluids and drill cuttings'' to read as follows:

§ 435.14 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT).

* * * * *

BCT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter	BCT effluent limitation
* * * * *	*	*
Drilling fluids and drill cuttings		
* * * * *	*	*
(B) For facilities located beyond 3 miles from shore		
Water-based drilling fluids and drill cuttings	Free oil	No discharge [2].
Non-aqueous drilling fluids		No discharge.
Cuttings associated with non-aqueous drilling fluids	Free oil	No discharge [2].
* * * * *	*	*

[2] As determined by the static sheen test (Appendix 1).

6. In § 435.15 the table is amended by revising entry B under the entry for ''Drilling fluids and drill cuttings'' and by revising footnote 2 and adding footnotes 5–9 to read as follows:

§ 435.15 Standards of performance for new sources (NSPS).

* * * * *

NEW SOURCE PERFORMANCE STANDARDS

Waste source	Pollutant parameter	NSPS
* * * * *	*	*
Drilling fluids and drill cuttings		
* * * * *	*	*
(B) For facilities located beyond 3 miles from shore		
Water-based drilling fluids and drill cuttings	SPP Toxicity	Minimum 96-hour LC50 of the SPP shall be 3% by volume [2].
	Free oil	No discharge [3].
	Diesel oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids		No discharge.
Cuttings associated with non-aqueous drilling fluids		
Stock Limitations	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Polynuclear Aromatic Hydrocarbons (PAH)	Maximum 10 ppm wt. PAH based on phenanthrene/wt. of stock base fluid [5].
	Sediment Toxicity	10-day LC_{50} of stock base fluid minus 10-day LC_{50} of $C_{16}-C_{18}$ internal olefin shall not be less than zero [6].
	Biodegradation Rate	Percent stock base fluid degraded at 120 days minus percent $C_{16}-C_{18}$ internal olefin degraded at 120 days shall not be less than zero [7].
Discharge Limitations	Diesel oil	No discharge.
	Free oil	No discharge [3].
	Formation oil	No discharge [8].
	Base fluid retained on cuttings	Maximum weighted average for well shall be 10.2 percent [9].

NEW SOURCE PERFORMANCE STANDARDS—Continued

Waste source	Pollutant parameter	NSPS
* * * * * * *		

* * * * *

[2] As determined by the suspended particulate phase toxicity test (Appendix 2).

[3] As determined by the static sheen test (Appendix 1).

* * * * *

[5] As determined by EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector in Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA–821–R–92–008 [Incorporated by reference and available from National Technical Information Service (NTIS) (703/605–6000)].

[6] As determined by ASTM E1367–92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods (Incorporated by reference and available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in Appendix 3.

[7] As determined by the biodegradation test (Appendix 4).

[8] As determined by the GC/MS baseline and assurance method (Appendix 5), and by the RPE method applied to drilling fluid removed from cuttings at primary shale shakers (Appendix 6).

[9] Maximum permissible retention of base fluid on wet cuttings averaged over drill intervals using non-aqueous drilling fluids as determined by retort method (Appendix 7).

7. Subpart A is amended by adding Appendices 3 through 7 as follows:

Appendix 3 to Subpart A of Part 435—Procedure for Mixing Base Fluids with Sediments

This procedure describes a method for amending uncontaminated and nontoxic (control) sediments with the base fluids that are used to formulate synthetic-based drilling fluids and other non-aqueous drilling fluids. Initially, control sediments shall be press-sieved through a 2000 micron mesh sieve to remove large debris. Then press-sieve the sediment through a 500 micron sieve to remove indigenous organisms that may prey on the test species or otherwise confound test results. Homogenize control sediment to limit the effects of settling that may have occurred during storage. Sediments should be homogenized before density determinations and addition of base fluid to control sediment. Because base fluids are strongly hydrophobic and do not readily mix with sediment, care must be taken to ensure base fluids are thoroughly homogenized within the sediment. All concentrations are weight-to-weight (mg of base fluid to kg of dry control sediment). Sediment and base fluid mixing should be accomplished by using the following method.

1. Determine the wet to dry ratio for the control sediment by weighing approximately 10 g subsamples of the screened and homogenized wet sediment into tared aluminum weigh pans. Dry sediment at 105°C for 18–24 h. Remove sediment and cool in a desiccator until a constant weight is achieved. Re-weigh the samples to determine the dry weight. Determine the wet/dry ratio by dividing the net wet weight by the net dry weight:

$$\frac{\text{Wet Sediment Weight (g)}}{\text{Dry Sediment Weight (g)}} = \text{Wet to Dry Ratio} \qquad [1]$$

2. Determine the density (g/mL) of the wet control or dilution sediment. This will be used to determine total volume of wet sediment needed for the various test treatments.

$$\frac{\text{Mean Wet Sediment Weight (g)}}{\text{Mean Wet Sediment Volume (mL)}} = \text{Wet Sediment Density (g/mL)} \qquad [2]$$

3. To determine the amount of base fluid needed to obtain a test concentration of 500 mg base fluid per kg dry sediment use the following formulas:

Determine the amount of wet sediment required:

$$\begin{matrix}\text{Wet Sediment}\\ \text{Density (g/mL)}\end{matrix} \times \begin{matrix}\text{Volume of Sediment Required}\\ \text{per Concentration (mL)}\end{matrix} = \begin{matrix}\text{Weight Wet Sediment}\\ \text{Required per Conc. (g)}\end{matrix} \qquad [3]$$

Determine the amount of dry sediment in kilograms (kg) required for each concentration:

$$\frac{\text{Wet Sediment per Concentration (g)}}{\text{(Mean Wet to Dry Ratio)}} \times \frac{1\text{kg}}{1000\text{g}} = \text{Dry Weight Sediment (kg)} \qquad [4]$$

Finally, determine the amount of base fluid required to spike the control sediment at each concentration:

$$\text{Conc. Desired (mg/kg)} \times \text{Dry Weight Sediment (kg)} = \text{Base Fluid Required (mg)} \qquad [5]$$

4. For primary mixing, place appropriate amounts of weighed base fluid into stainless mixing bowls, tare the vessel weight, then add sediment and mix with a high-shear dispersing impeller for 9 minutes. The concentration of base fluid in sediment from this mix , rather than the nominal concentration, shall be used in calculating LC50 values.

5. Tests for homogeneity of base fluid in sediment are to be performed during the procedure development phase. Because of difficulty of homogeneously mixing base fluid with sediment, it is important to demonstrate that the base fluid is evenly mixed with sediment. The sediment should be analyzed for total petroleum hydrocarbons (TPH) using EPA Methods 3550A and 8015M, with samples taken both prior to and after distribution to replicate test containers. Base-fluid content is measured as TPH. After mixing the sediment, a minimum of three replicate sediment samples should be taken prior to distribution into test containers. After the test sediment is distributed to test containers, an additional three sediment samples should be taken from three test containers to ensure proper distribution of base fluid within test containers. Base-fluid content results should be reported within 48 hours of mixing. The coefficient of variation (CV) for the replicate samples must be less than 20%. If base-fluid content results are not within the 20% CV limit, the test sediment should be remixed. Tests should not begin until the CV is determined to be below the maximum limit of 20%. During the test, a minimum of three replicate containers should be sampled to determine base-fluid content during each sampling period.

6. Mix enough sediment in this way to allow for its use in the preparation of all test concentrations and as a negative control. When commencing the sediment toxicity test, range-finding tests may be required to determine the concentrations that produce a toxic effect if these data are otherwise unavailable. The definitive test should bracket the LC50, which is the desired endpoint. The results for the base fluids will be reported in mg of base fluid per kg of dry sediment.

References

American Society for Testing and Materials (ASTM). 1996. Standard Guide for Collection, Storage, Characterization, and Manipulation of Sediments for Toxicological Testing. ASTM E 1391–94. Annual Book of ASTM Standards, Volume 11.05, pp. 805–825.

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U.S. EPA. 1994. Methods for Assessing the Toxicity of Sediment-associated Contaminants with Estuarine and Marine Amphipods. EPA/600/R–94/025. Office of Research and Development, Washington, DC.

Appendix 4 to Subpart A of Part 435—Determination of Biodegradation of Synthetic Base Fluids in a Solid-Phase Test System

Summary of Method

This analytical method determines the biodegradation potential of mineral, paraffinic, and diesel oils as well as synthetic materials that are used as base fluids in the formulation of drilling fluids. The base fluids are mixed with sediment at an initial concentration of 500 mg/kg dry sediment, and placed under flowing seawater at 12°C. Base fluid concentration measurements are made at Days 0, 14, 28, 56, and 120. This method uses two parameters, base-fluid content and redox potential in both poisoned and unpoisoned sediment, to assess the rate of biodegradation of base fluids.

Sample Requirements

1. The exposure system is a flowing seawater system providing a laminar flow over replicate test containers for a test duration of 120 days. For each base fluid there are two treatments: (1) base fluid-dosed sediment; and (2) base fluid-dosed sediment poisoned with biocide (used to measure the abiotic degradation of the base fluids).

2. To prevent cross-contamination, individual exposure tables should be used for each treatment and control. Exposure tables should be constructed of non-contaminating material and should be large enough to hold the required number of replicate test containers. Seawater should enter one end of the table, flow uniformly over test containers, and exit the opposite end of the table.

3. Sampling should be conducted on Days 0, 14, 28, 56, and 120. Sampling consists of three replicate samples taken on each sampling day for determination of redox potential and base-fluid content.

4. For Day 0 sampling, all samples should be taken from the initial batch of test treatment sediment prior to distribution into replicate exposure containers. Sufficient test treatment sediment must be made for a minimum of 30 replicate samples to be taken throughout the study (see Table 1).

TABLE 1.—REPLICATE REQUIREMENTS PER TREATMENT AND CONTROL TESTS

[Replication per sampling period]

Sampling period	Unpoisoned sediment		Poisoned sediment	
	Redox potential	Base-fluid content*	Redox potential	Base-fluid Content*
DAY 0	3	3	3	3
DAY 14	3**	3	3**	3
DAY 28	↓	3	↓	3
DAY 56	↓	3	↓	3
DAY 120	↓	3	↓	3
Totals Samples	6	15	6	15

* Sampling for base-fluid content is destructive, therefore samples must be taken from a different replicate set of three sampling containers for each sampling date.

** Sampling for redox potential is non-destructive, therefore samples may be taken from the same replicate set of three sample containers for each sampling date after Day 0.

Mixing Methods

Because base fluids are strongly hydrophobic and do not readily mix with sediments, care must be taken to ensure base fluids are thoroughly homogenized within the sediment. All concentrations are weight-to-weight (mg of base fluid to kg of dry control sediment). Sediment and base fluid mixing will be accomplished by using the following method.

1. Determine the wet to dry ratio for the control sediment by weighing approximately 10 g subsamples of the screened and homogenized wet sediment into tared aluminum weigh pans. Dry sediment at 105°C for 18–24 h. Remove sediment and cool in a desiccator until a constant weight is achieved. Re-weigh the samples to determine the dry weight. Determine the wet/dry ratio by dividing the net wet weight by the net dry weight using Formula 1. This is required to determine the weight of wet sediment needed to prepare the test concentration of 500 mg of base fluid per kg of dry sediment (500 ppm).

$$\frac{\text{Wet Sediment Weight (g)}}{\text{Dry Sediment Weight (g)}} = \text{Wet to Dry Ratio} \qquad [1]$$

2. Determine the density (g/mL) of the wet control or dilution sediment. This will be used to determine total volume of wet sediment needed for the various test treatments.

$$\frac{\text{Mean Wet Sediment Weight (g)}}{\text{Mean Wet Sediment Volume (mL)}} = \text{Wet Sediment Density (g/mL)} \qquad [2]$$

3. To determine the amount of base fluid needed to obtain a test concentration of 500 mg base fluid per kg dry sediment use the following formulas:

Determine the amount of wet sediment required:

$$\text{Wet Sediment Density (g/mL)} \times \text{Volume of Sediment Required per Concentration (mL)} = \text{Weight Wet Sediment Required per Conc. (g)} \qquad [3]$$

Determine the amount of dry sediment in kilograms (kg) required for each concentration:

$$\frac{\text{Wet Sediment per Concentration (g)}}{\text{(Mean Wet to Dry Ratio)}} \times \frac{1\text{kg}}{1000\text{g}} = \text{Dry Weight Sediment (kg)} \qquad [4]$$

Finally, determine the amount of base fluid to provide the initial test concentration of 500 mg/kg dry sediment:

$$(500\ \text{mg/kg}) \times \text{Dry Weight Sediment (kg)} = \text{Base Fluid Required (mg)} \qquad [5]$$

4. Based on the required number (42) and size (approximately 500 mL) of samples, the approximate volume of sediment needed is 25 L. Mixing should be performed in 5 L batches, then combined and remixed. For primary mixing, place appropriate amounts of weighed base fluid into stainless mixing bowls, tare the vessel weight, then add sediment and mix with a high-shear dispersing impeller for 9 minutes.

5. Secondary mixing should be conducted in a large container (i.e., cement mixer) and mixing should be for a minimum of 10 minutes. Day 0 samples will be taken from this batch of test sediment.

6. Biocide additions are to be mixed after all other mixing is complete.

Base-Fluid Content

Because of difficulty of homogeneously mixing base fluid with sediment, it is important to demonstrate that the base fluid is evenly mixed with sediment. The sediment should be analyzed for total petroleum hydrocarbons (TPH) using EPA Methods 3550A and 8015M, with samples taken both prior to and after distribution to replicate test containers. Base-fluid content is measured as TPH. After mixing the 25L batch of sediment test concentration, a minimum of three replicate sediment samples will be taken prior to distribution into test containers. After the test sediment is distributed to test containers, an additional three sediment samples shall be taken from three test containers to ensure proper distribution of base fluid within test containers. Base-fluid content results should be reported within 48 hours of mixing. Measured and nominal concentrations should be reported for initial test concentrations. The coefficient of variation (CV) for the replicate samples must be less than 20%. If base-fluid content results are not within the 20% CV limit, the test sediment should be remixed. Tests should not begin until the CV is determined to be below the maximum limit of 20%. During the test, a minimum of three replicate containers should be sampled to determine base-fluid content during each sampling period.

Water Quality Measurements

The following water quality measurements of the overlying water should be taken daily: dissolved oxygen (DO), pH, temperature, and salinity.

Measurement of Redox Potential

1. The oxidation-reduction (redox) potential of a sediment is a quantitative expression of its oxidizing or reducing tendency. Redox potential is expressed as an E_h value, E_h being the electron motive force (in mV) of an oxidation-reduction system referred to as a standard hydrogen half-cell. Positive E_h values are characteristic of well oxygenated, coarse sediments or those with very low concentrations of organic matter. Conversely, negative E_h values occur in deoxygenated sediments rich in organic matter and largely consisting of fine particles. A redox profile follows changes in redox potential at increasing depths from the sediment surface.

2. The redox potential should be measured using a combination platinum/reference (Ag/AgCL) electrode held in an adjustable retort stand, one revolution resulting in a lowering of the probe by 5 mm. Readings should be taken after one minute and values for Zobell's solution (g L^{-1}; potassium ferrocyanide, 1.399; potassium ferricyanide, 1.087; potassium chloride, 7.456) and sea water should be monitored after each depth profile. Actual readings should be adjusted to E_h by adding 198.

Appendix 5 to Subpart A of Part 435—Determination of Crude Oil Contamination in Non-Aqueous Drilling Fluids by Gas Chromatography/Mass Spectrometry (GC/MS)

1.0 Scope and Application

1.1 This method determines crude (formation) oil contamination, or other petroleum oil contamination, in non-aqueous drilling fluids (NAFs) by comparing the gas chromatography/mass spectrometry (GC/MS) fingerprint scan and extracted ion scans of the test sample to that of an uncontaminated sample.

1.2 This method can be used for monitoring oil contamination of NAFs or monitoring oil contamination of the base fluid used in the NAF formulations.

1.3 Any modification of this method beyond those expressly permitted shall be considered as a major modification subject to application and approval of alternative test procedures.

1.4 The gas chromatography/mass spectrometry portions of this method are restricted to use by, or under the supervision of analysts experienced in the use of GC/MS and in the interpretation of gas chromatograms and extracted ion scans. Each laboratory that uses this method must generate acceptable results using the procedures described in Sections 7, 9.2, and 12 of this method.

2.0 Summary of Method

2.1 Analysis of NAF for crude oil contamination is a step-wise process. Qualitative assessment of the presence or absence of crude oil is performed first. If crude oil is detected in this qualitative assessment, quantitative analysis of the crude oil concentration is performed.

2.2 A sample of NAF is centrifuged, to obtain a solids free supernate.

2.3 The sample to be tested is prepared by removing an aliquot of the solids free supernate, spiking it with internal standard, and analyzing it using GC/MS techniques. The components are separated by the gas chromatograph and detected by the mass spectrometer.

2.4 Qualitative identification of crude oil contamination is performed by comparing the Total Ion Chromatograph (TIC) scans and Extracted Ion Profile (EIP) scans of test sample to that of uncontaminated base fluids, and examining the profiles for chromatographic signatures diagnostic of oil contamination.

2.5 The presence or absence of crude oil contamination observed in the full scan profiles and selected extracted ion profiles determines further sample quantitation and reporting.

2.6 If crude oil is detected in the qualitative analysis, quantitative analysis is performed by calibrating the GC/MS using a designated NAF spiked with known concentrations of a designated oil.

2.7 Quality is assured through reproducible calibration and testing of GC/MS system and through analysis of quality control samples.

3.0 Definitions

3.1 A NAF is one in which the continuous phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhance mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).
3.2 TIC—Total Ion Chromatograph.
3.3 EIP—Extracted Ion Profile.
3.4 TCB—1,3,5–trichlorobenzene is used as the internal standard in this method.
3.5 SPTM—System Performance Test Mix standards are used to establish retention times and monitor detection levels.

4.0 Interferences and Limitations

4.1 Solvents, reagents, glassware, and other sample processing hardware may yield artifacts and/or elevated baselines causing misinterpretation of chromatograms.
4.2 All Materials used in the analysis shall be demonstrated to be free from interferences by running method blanks. Specific selection of reagents and purification of solvents by distillation in all-glass systems may be required.
4.3 Glassware is cleaned by rinsing with solvent and baking at 400°C for a minimum of 1 hour.
4.4 Interferences may vary from source to source, depending on the diversity of the samples being tested.
4.5 Variations in and additions of base fluids and/or drilling fluid additives (emulsifiers, dispersants, fluid loss control agents, etc.) might also cause interferences and misinterpretation of chromatograms.
4.6 Difference in light crude oils, medium crude oils, and heavy crude oils will result in different responses and thus different interpretation of scans and calculated percentages.

5.0 Safety

5.1 The toxicity or carcinogenicity of each reagent used in this method has not been precisely determined; however each chemical should be treated as a potential health hazard. Exposure to these chemicals should be reduced to the lowest possible level.
5.2 Unknown samples may contain high concentration of volatile toxic compounds. Sample containers should be opened in a hood and handled with gloves to prevent exposure. In addition, all sample preparation should be conducted in a fume hood to limit the potential exposure to harmful contaminates.
5.3 This method does not address all safety issues associated with its use. The laboratory is responsible for maintaining a safe work environment and a current awareness file of OSHA regulations regarding the safe handling of the chemicals specified in this method. A reference file of material safety data sheets (MSDSs) should be available to all personnel involved in these analyses. Additional references to laboratory safety can be found in References 16.1 through 16.3.
5.4 NAF base fluids may cause skin irritation, protective gloves are recommended while handling these samples.

6.0 Apparatus and Materials

Note: Brand names, suppliers, and part numbers are for illustrative purposes only. No endorsement is implied. Equivalent performance may be achieved using apparatus and materials other than those specified here, but demonstration of equivalent performance meeting the requirements of this method is the responsibility of the laboratory.
6.1 Equipment for glassware cleaning.
6.1.1 Laboratory sink with overhead fume hood.
6.1.2 Kiln—Capable of reaching 450°C within 2 hours and holding 450°C within ±10°C, with temperature controller and safety switch (Cress Manufacturing Co., Santa Fe Springs, CA B31H or X31TS or equivalent).
6.2 Equipment for sample preparation.
6.2.1 Laboratory fume hood.
6.2.2 Analytical balance—Capable of weighing 0.1 mg.
6.2.3 Glassware.
6.2.3.1 Disposable pipettes—Pasteur, 150 mm long by 5 mm ID (Fisher Scientific 13–678–6A, or equivalent) baked at 400°C for a minimum of 1 hour.
6.2.3.2 Glass volumetric pipettes or gas tight syringes—1.0-mL ±1% and 0.5-mL ±1%.
6.2.3.3 Volumetric flasks—Glass, class A, 10-mL, 50-mL and 100-mL.
6.2.3.4 Sample vials—Glass, 1- to 3-mL (baked at 400°C for a minimum of 1 hour) with PTFE-lined screw or crimp cap.
6.2.3.5 Centrifuge and centrifuge tubes—Centrifuge capable of 10,000 rpm, or better, (International Equipment Co., IEC Centra MP4 or equivalent) and 50-mL centrifuge tubes (Nalgene, Ultratube, Thin Wall 25×89 mm, #3410–2539).
6.3 Gas Chromatograph/Mass Spectrometer (GC/MS):
6.3.1 Gas Chromatograph—An analytical system complete with a temperature-programmable gas chromatograph suitable for split/splitless injection and all required accessories, including syringes, analytical columns, and gases.
6.3.1.1 Column—30 m (or 60 m) × 39 0.32 mm ID (or 0.25 mm ID) 1µm film thickness (or 0.25µm film thickness) silicone-coated fused-silica capillary column (J&W Scientific DB–5 or equivalent).
6.3.2 Mass Spectrometer—Capable of scanning from 35 to 500 amu every 1 sec or less, using 70 volts (nominal) electron energy in the electron impact ionization mode (Hewlett Packard 5970MS or comparable).
6.3.3 GC/MS interface—the interface is a capillary-direct interface from the GC to the MS.
6.3.4 Data system—A computer system must be interfaced to the mass spectrometer. The system must allow the continuous acquisition and storage on machine-readable media of all mass spectra obtained throughout the duration of the chromatographic program. The computer must have software that can search any GC/MS data file for ions of a specific mass and that can plot such ion abundance versus retention time or scan number. This type of plot is defined as an Extracted Ion Current Profile (EIP). Software must also be available that allows integrating the abundance in any total ion chromatogram (TIC) or EIP between specified retention time or scan-number limits. It is advisable that the most recent version of the EPA/NIST Mass Spectral Library be available.

7.0 Reagents and Standards

7.1 Methylene chloride—Pesticide grade or equivalent. Used when necessary for sample dilution.
7.2 Standards—Prepare from pure individual standard materials or purchased as certified solutions. If compound purity is 96% or greater, the weight may be used without correction to compute the concentration of the standard.
7.2.1 Crude Oil Reference—Obtain a sample of a crude oil with a known API gravity. This oil will be used in the calibration procedures.
7.2.2 Synthetic Base Fluid—Obtain a sample of clean internal olefin (IO) Lab drilling fluid (as sent from the supplier—has not been circulated downhole). This drilling fluid will be used in the calibration procedures.
7.2.3 Internal standard—Prepare a 0.01 g/mL solution of 1,3,5-trichlorobenzene (TCB). Dissolve 1.0 g of TCB in methylene chloride and dilute to volume in a 100-mL volumetric flask. Stopper, vortex, and transfer the solution to a 150-mL bottle with PTFE-lined cap. Label appropriately, and store at −5°C to 20°C. Mark the level of the meniscus on the bottle to detect solvent loss.

7.2.4 GC/MS system performance test mix (SPTM) standards—The SPTM standards should contain octane, decane, dodecane, tetradecane, tetradecene, toluene, ethylbenzene, 1,2,4-trimethylbenzene, 1-methylnaphthalene and 1,3-dimethylnaphthalene. These compounds can be purchased individually or obtained as a mixture (i.e. Supelco, Catalog No.4–7300). Prepare a high concentration of the SPTM standard at 62.5 mg/mL in methylene chloride. Prepare a medium concentration SPTM standard at 1.25 mg/mL by transferring 1.0 mL of the 62.5 mg/mL solution into a 50 mL volumetric flask and diluting to the mark with methylene chloride. Finally, prepare a low concentration SPTM standard at 0.125 mg/mL by transferring 1.0 mL of the 1.25 mg/mL solution into a 10-mL volumetric flask and diluting to the mark with methylene chloride.

7.2.5 Crude oil/drilling fluid calibration standards—Prepare a 4-point crude oil/drilling fluid calibration at concentrations of 0% (no spike—clean drilling fluid), 0.5%, 1.0%, and 2.0% by weight according to the procedures outlined below using the Reference Crude Oil:

7.2.5.1 Label 4 jars with the following identification: Jar 1—0%Ref-IOLab, Jar 2—0.5%Ref-IOLab, Jar 3—1%Ref-IOLab, and Jar 4—2%Ref-IOLab.

7.2.5.2 Weigh 4, 50-g aliquots of well mixed IO Lab drilling fluid into each of the 4 jars.

7.2.5.3 Add Reference Oil at 0.5%, 1.0%, and 2.0% by weight to jars 2, 3, and 4 respectively. Jar 1 will not be spiked with Reference Oil in order to retain a ''0%'' oil concentration.

7.2.5.4 Thoroughly mix the contents of each of the 4 jars, using clean glass stirring rods.

7.2.5.5 Transfer (weigh) a 30-g aliquot from Jar 1 to a labeled centrifuge tube. Centrifuge the aliquot for a minimum of 15 min at approximately 15,000 rpm, in order to obtain a solids free supernate. Weigh 0.5 g of the supernate directly into a tared and appropriately labeled GC straight vial. Spike the 0.5-g supernate with 500 µL of the 0.01g/mL 1,3,5-trichlorobenzene internal standard solution (see 7.2.3), cap with a Teflon lined crimp cap, and vortex for ca. 10 sec.

7.2.5.6 Repeat step 7.2.5.5 except use an aliquot from Jar 2.

7.2.5.7 Repeat step 7.2.5.5 except use an aliquot from Jar 3.

7.2.5.8 Repeat step 7.2.5.5 except use an aliquot from Jar 4.

7.2.5.9 These 4 crude/oil drilling fluid calibration standards are now used for qualitative and quantitative GC/MS analysis.

7.2.6 Precision and recovery standard (mid level crude oil/drilling fluid calibration standard)—Prepare a mid point crude oil/drilling fluid calibration using IO Lab drilling fluid and Reference Oil at a concentration of 1.0% by weight. Prepare this standard according to the procedures outlined in Section 7.2.5.1 through 7.2.5.5, with the exception that only ''Jar 3'' needs to be prepared. Remove and spike with internal standard, as many 0.5-g aliquots as needed to complete the GC/MS analysis (see Section 11.6—bracketing authentic samples every 12 hours with precision and recovery standard) and the initial demonstration exercise described in Section 9.2.

7.2.7 Stability of standards

7.2.7.1 When not used, standards are stored in the dark, at −5 to −20°C in screw-capped vials with PTFE-lined lids. A mark is placed on the vial at the level of the solution so that solvent loss by evaporation can be detected. The vial is brought to room temperature prior to use.

7.2.7.2 Solutions used for quantitative purposes shall be analyzed within 48 hours of preparation and on a monthly basis thereafter for signs of degradation. Standard will remain acceptable if the peak area remains within ±15% of the area obtained in the initial analysis of the standard.

8.0 Sample Collection Preservation and Storage

8.1 NAF samples and base fluid samples are collected in 100–to 200–mL glass bottles with PTFE–or aluminum foil lined caps.

8.2 Samples collected in the field will be stored refrigerated until time of preparation.

8.3 Sample and extract holding times for this method have not yet been established. However, based on tests experience samples should be analyzed within seven to ten days of collection and extracts analyzed within seven days of preparation.

8.4 After completion of GC/MS analysis, extracts should be refrigerated at ca. 4°C until further notification of sample disposal.

9.0 Quality Control

9.1 Each laboratory that uses this method is required to operate a formal quality assurance program (Reference 16.4). The minimum requirements of this program consist of an initial demonstration of laboratory capability, and 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.

9.1.1 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 9.2.

9.1.2 The analyst is permitted to modify this method to improve separations or lower the cost of measurements, provided all performance requirements are met. Each time a modification is made to the method, the analyst is required to repeat the calibration (Section 10.4) and to repeat the initial demonstration procedure described in Section 9.2.

9.1.3 Analyses of blanks are required to demonstrate freedom from contamination. The procedures and criteria for analysis of a blank are described in Section 9.3.

9.1.4 An analysis of a matrix spike sample is required to demonstrate method accuracy. The procedure and QC criteria for spiking are described in Section 9.4.

9.1.5 Analysis of a duplicate field sample is required to demonstrate method precision. The procedure and QC criteria for duplicates are described in Section 9.5.

9.1.6 Analysis of a sample of the clean NAF(s) (as sent from the supplier—has not been circulated downhole) used in the drilling operations is required.

9.1.7 The laboratory shall, on an ongoing basis, demonstrate through calibration verification and the analysis of the precision and recovery standard (Section 7.2.6) that the analysis system is in control. These procedures are described in Section 11.6.

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

9.2 Initial precision and accuracy—The initial precision and recovery test is performed using the precision and recovery standard (1% by weight Reference Oil in IO Lab drilling fluid). The laboratory shall generate acceptable precision and recovery by performing the following operations.

9.2.1 Prepare four separate aliquots of the precision and recovery standard using the procedure outlined in Section 7.2.6. Analyze these aliquots using the procedures outlined in Section 11.

9.2.2 Using the results of the set of four analyses, compute the average recovery (X) in weight percent and the standard deviation of the recovery (s) for each sample.

9.2.3 If s and X meet the acceptance criteria of 80% to 110%, 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, review this method, correct the problem, and repeat the test.

9.2.4 Accuracy and precision—The average percent recovery (P) and the standard deviation of the percent recovery (S_p) Express the accuracy assessment as a percent recovery interval from $P-2S_p$ to $P+2S_p$. For example, if P=90% and S_p=10% for four analyses of crude oil in NAF, the accuracy interval is expressed as 70% to 110%. Update the accuracy assessment on a regular basis.

9.3 Blanks—Rinse glassware and centrifuge tubes used in the method with ca. 30 mL of methylene chloride, remove a 0.5-g aliquot of the solvent, spike it with the 500 µL of the internal standard solution (Section 7.2.3) and analyze a 1-µL aliquot of the blank sample using the procedure in Section 11. Compute results per Section 12.

9.4 Matrix spike sample—Prepare a matrix spike sample according to procedure outlined in Section 7.2.6. Analyze the sample and calculate the concentration (% oil) in the drilling fluid and % recovery of oil from the spiked drilling fluid using the methods described in Sections 11 and 12.

9.5 Duplicates—A duplicate field sample is prepared according to procedures outlined in Section 7.3 and analyzed according to Section 11. The relative percent difference (RPD) of the calculated concentrations should be less than 15%.

9.5.1 Analyze each of the duplicates per the procedure in Section 11 and compute the results per Section 12.

9.5.2 Calculate the relative percent difference (RPD) between the two results per the following equation:

$$RPD = \frac{D_1 - D_2}{\left(D_1 + D_2\right)/2} \times 100$$

where:

D_1 = Concentration of crude oil in the sample

D_2 = Concentration of crude oil in the duplicate sample

9.5.3 If the RPD 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 batch reanalyzed.

9.6 Preparation of the clean NAF sample is performed according to procedures outlined in Section 7.3 except that the clean NAF (drilling fluid that has not been circulated downhole) is used. Ultimately the oil-equivalent concentration from the TIC or EIP signal measured in the clean NAF sample will be subtracted from the corresponding authentic field samples in order to calculate the true contaminant concentration (% oil) in the field samples (see Section 12).

9.7 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 initial precision and recovery (Section 9.2) and ongoing precision and recovery (Section 11.6) shall be identical, so that the most precise results will be obtained. The GC/MS instrument will provide the most reproducible results if dedicated to the setting and conditions required for the analyses given in this method.

9.8 Depending on specific program requirements, field replicates and field spikes of crude oil into samples may be required when this method is used to assess the precision and accuracy of the sampling and sample transporting techniques.

10.0 Calibration

10.1 Establish gas chromatographic/mass spectrometer operating conditions given in Table 1 below. Perform the GC/MS system hardware-tune as outlined by the manufacture. The gas chromatograph is calibrated using the internal standard technique.

Note: Because each GC is slightly different, it may be necessary to adjust the operating conditions (carrier gas flow rate and column temperature and temperature program) slightly until the retention times in Table 2 are met.

TABLE 1.—GAS CHROMATOGRAPH/MASS SPECTROMETER (GC/MS) OPERATING CONDITIONS

Parameter	Setting
Injection port	280°C.
Transfer line	280°C.
Detector	280°C.
Initial Temperature	50°C.
Initial Time	5 minutes.
Ramp	50 to 300°C @ 5 C per minute.
Final Temperature	300°C.
Final Hold	20 minutes or until all peaks have eluted.
Carrier Gas	Helium.
Flow rate	As required for standard operation.
Split ratio	As required to meet performance criteria (~1:100).
Mass range	35 to 600 amu.

TABLE 2.—APPROXIMATE RETENTION TIMES FOR COMPOUNDS

Compound	Approximate Retention Time (minutes)
Toluene	5.6
Octane, n-C_8	7.2
Ethylbenzene	10.3
1,2,4-Trimethylbenzene	16.0
Decane, n-C_{10}	16.1
TCB (Internal Standard)	21.3
Dodecane, n-C_{12}	22.9
1-Methylnaphthalene	26.7
1-Tetradecene	28.4
Tetradecane, n-C_{14}	28.7
1,3-Dimethylnaphthalene	29.7

10.2 Internal standard calibration procedure—1,3,5-trichlorobenzene (TCB) has been shown to be free of interferences from diesel and crude oils and is a suitable internal standard.

10.3 The system performance test mix standards prepared in Section 7.2.4 are primarily used to establish retention times and establish qualitative detection limits.

10.3.1 Spike a 500-mL aliquot of the 1.25 mg/mL SPTM standard with 500 µL of the TCB internal standard solution.

10.3.2 Inject 1.0 µL of this spiked SPTM standard onto the GC/MS in order to demonstrate proper retention times. For the GC/MS used in the development of this method the ten compounds in the mixture had typical retention times shown in Table 2 above. Extracted ion scans for m/z 91 and 105 showed a maximum abundance of 400,000.

10.3.3 Spike a 500-mL aliquot of the 0.125 mg/mL SPTM standard with 500 µL of the TCB internal standard solution.

10.3.4 Inject 1.0 µL of this spiked SPTM standard onto the GC/MS to monitor detectable levels. For the GC/MS used in the development of this test all ten compounds showed a minimum peak height of three times signal to noise. Extracted ion scans for m/z 91 and 105 showed a maximum abundance of 40,000.

10.4 GC/MS crude oil/drilling fluid calibration —There are two methods of quantification: Total Area Integration (C_8—C_{13}) and EIP Area Integration using m/z's 91 and 105. The Total Area Integration method can be used as the primary technique for quantifying crude oil in NAFs. The EIP Area Integration method can be used as a confirmatory technique for NAFs. The EIP Area Integration method should be used as the primary method for quantifying oil in enhanced mineral oil (EMO) based drilling fluid. Inject 1.0 µL of each of the four crude oil/drilling fluid calibration standards prepared in Section 7.2.5 into the GC/MS. The internal standard should elute approximately 21–22 minutes after injection. For the GC/MS used in the development of this method, the internal standard peak was (35 to 40)% of full scale at an abundance of about 3.5e+07.

10.4.1 Total Area Integration Method—For each of the four calibration standards obtain the following: Using a straight baseline integration technique, obtain the total ion chromatogram (TIC) area from C_8 to C_{13}. Obtain the TIC area of the internal standard (TCB). Subtract the TCB area from the C_8—C_{13} area to obtain the true C_8—C_{13} area. Using the C_8—C_{13} and TCB areas, and known internal standard concentration, generate a linear regression calibration using the internal standard method. The r^2 value for the linear regression curve should be ≥ 0.998. Some synthetic fluids might have peaks that elute in the window and would interfere with the analysis. In this case the integration window can be shifted to other areas of scan where there are no interfering peaks from the synthetic base fluid.

10.4.2 EIP Area Integration—For each of the four calibration standards generate Extracted Ion Profiles (EIPs) for m/z 91 and 105. Using straight baseline integration techniques, obtain the following EIP areas:

10.4.2.1 For m/z 91 integrate the area under the curve from approximately 9 minutes to 21—22 minutes, just prior to but not including the internal standard.

10.4.2.2 For m/z 105 integrate the area under the curve from approximately 10.5 minutes to 26.5 minutes.

10.4.2.3 Obtain the internal standard area from the TCB in each of the four calibration standards, using m/z 180.

10.4.2.4 Using the EIP areas for TCB, m/z 91 and m/z105, and the known concentration of internal standard, generate linear regression calibration curves for the target ions 91 and 105 using the internal standard method. The r^2 value for the each of the EIP linear regression curves should be ≥ 0.998.

10.4.2.5 Some base fluids might produce a background level that would show up on the extracted ion profiles, but there should not be any real peaks (signal to noise ratio of 1:3) from the clean base fluids.

11.0 Procedure

11.1 Sample Preparation—

11.1.1 Mix the authentic field sample (drilling fluid) well. Transfer (weigh) a 30-g aliquot of the sample to a labeled centrifuge tube.

11.1.2 Centrifuge the aliquot for a minimum of 15 min at approximately 15,000 rpm, in order to obtain a solids free supernate.

11.1.3 Weigh 0.5 g of the supernate directly into a tared and appropriately labeled GC straight vial.

11.1.4 Spike the 0.5-g supernate with 500 µL of the 0.01g/mL 1,3,5-trichlorobenzene internal standard solution (see 7.2.3), cap with a Teflon lined crimp cap, and vortex for ca. 10 sec.

11.1.5 The sample is ready for GC/MS analysis.

11.2 Gas Chromatography.

Table 1 summarizes the recommended operating conditions for the GC/MS. Retention times for the n-alkanes obtained under these conditions are given in Table 2. Other columns, chromatographic conditions, or detectors may be used if initial precision and accuracy requirements (Section 9.2) are met. The system is calibrated according to the procedures outlined in Section 10, and verified every 12 hours according to Section 11.6.

11.2.1 Samples should be prepared (extracted) in a batch of no more than 20 samples. The batch should consist of 20 authentic samples, 1 blank (Section 9.3), 1 matrix spike sample (9.4), and 1 duplicate field sample (9.5), and a prepared sample of the corresponding clean NAF used in the drilling process.

11.2.2 An analytical sequence is run on the GC/MS where the 3 SPTM standards (Section 7.2.4) containing internal standard are analyzed first, followed by analysis of the four GC/MS crude oil/drilling fluid calibration standards (Section 7.2.5), analysis of the blank, matrix spike sample, the duplicate sample, the clean NAF sample, followed by the authentic samples.

11.2.3 Samples requiring dilution due to excessive signal should be diluted using methylene chloride.

11.2.4 Inject 1.0 µL of the test sample or standard into the GC, using the conditions in Table 1.

11.2.5 Begin data collection and the temperature program at the time of injection.

11.2.6 Obtain a TIC and EIP fingerprint scans of the sample (Table 3).

11.2.7 If the area of the C_8 to C_{13} peaks exceeds the calibration range of the system, dilute a fresh aliquot of the test sample weighing < 0.50-g and reanalyze.

11.2.8 Determine the C_8 to C_{13} TIC area, the TCB internal standard area, and the areas for the m/z 91 and 105 EIPs. These are used in the calculation of oil concentration in the samples (see Section 12).

TABLE 3.—RECOMMENDED ION MASS NUMBERS

Selected ion mass numbers	Corresponding aromatic compounds	Typical retention times (in minutes)
91	Methylbenzene	6.0
	Ethylbenzene	10.3
	1,4-Dimethylbenzene	10.9
	1,3-Dimethylbenzene	10.9
	1,2-Dimethylbenzene	11.9
105	1,3,5-Trimethylbenzene	15.1
	1,2,4-Trimethylbenzene	16.0
	1,2,3-Trimethylbenzene	17.4
156	2,6-Dimethylnaphthalene	28.9
	1,2-Dimethylnaphthalene	29.4

TABLE 3.—RECOMMENDED ION MASS NUMBERS—Continued

Selected ion mass numbers	Corresponding aromatic compounds	Typical retention times (in minutes)
	1,3-Dimethylnaphthalene	29.7

11.2.9 Observe the presence of peaks in the EIPs that would confirm the presence of any target aromatic compounds. Using the EIP areas and EIP linear regression calibrations compare the abundance of the aromatic peaks, and if appropriate, determine approximate crude oil contamination in the sample for each of the target ions.

11.3 Qualitative Identification—See Section 17 for schematic flowchart.

11.3.1 Qualitative identification is accomplished by comparison of the TIC and EIP area data from an authentic sample to the TIC and EIP area data from the calibration standards (Section 12.4). Crude oil is identified by the presence of C_{10} to C_{13} n-alkanes and corresponding target aromatics.

11.3.2 Using the calibration data, establish the identity of the C_8 to C_{13} peaks in the chromatogram of the sample. Using the calibration data, establish the identity of any target aromatics present on the extracted ion scans.

11.3.3 Crude oil is not present in a detectable amount in the sample if there are no target aromatics seen on the extracted ion scans. The experience of the analyst shall weigh heavily in the determination of the presence of peaks at a signal-to-noise ratio of 3 or greater.

11.3.4 If the chromatogram shows n-alkanes from C_8 to C_{13} and target aromatics to be present, contamination by crude oil or diesel should be suspected and quantitative analysis should be determined. If there are no n-alkanes present that are not seen on the blank, and no target aromatics are seen, the sample can be considered to be free of contamination.

11.4 Quantitative Identification—

11.4.1 Determine the area of the peaks from C_8 to C_{13} as outlined in the calibration section (10.4.1). If the area of the peaks for the sample is greater than that for the clean NAF (base fluid) use the crude oil/drilling fluid calibration TIC linear regression curve to determine approximate crude oil contamination.

11.4.2 Using the EIPs outlined in Section 10.4.2 determine the presence of any target aromatics. Using the integration techniques outlined in Section 10.4.2 to obtain the EIP areas for m/z 91 and 105. Use the crude oil/drilling fluid calibration EIP linear regression curves to determine approximate crude oil contamination.

11.5 Complex Samples—

11.5.1 The most common interferences in the determination of crude oil can be from mineral oil, diesel oil, and proprietary additives in drilling fluids.

11.5.2 Mineral oil can typically be identified by it lower target aromatic content, and narrow range of strong peaks.

11.5.3 Diesel oil can typically be identified by low amounts of n-alkanes from C_7 to C_9, and the absence of n-alkanes greater than C_{25}.

11.5.4 Crude oils can usually be distinguished by the presence of high aromatics, increased intensities of C_8 to C_{13} peaks, and/or the presence of higher hydrocarbons of C_{25} and greater (which may be difficult to see in some synthetic fluids at low contamination levels).

11.5.4.1 Oil condensates from gas wells are low in molecular weight and will normally produce strong chromatographic peaks in the C8–C_{13} range. If a sample of the gas condensate crude oil from the formation is available, the oil can be distinguished from other potential sources of contamination by using it to prepare a calibration standard.

11.5.4.2 Asphaltene crude oils with API gravity <20 may not produce chromatographic peaks strong enough to show contamination at levels of the calibration. Extracted ion peaks should be easier to see than increased intensities for the C_8 to C_{13} peaks. If a sample of asphaltene crude from the formation is available, a calibration standard should be prepared.

11.6 System and Laboratory Performance—

11.6.1 At the beginning of each 8-hour shift during which analyses are performed, GC crude oil/drilling fluid calibration and system performance test mixes are verified. For these tests, analysis of the medium-level calibration standard (1-% Reference Oil in IO Lab drilling fluid, and 1.25 mg/mL SPTM with internal standard) shall be used to verify all performance criteria. Adjustments and/or re-calibration (per Section 10) shall be performed until all performance criteria are met. Only after all performance criteria are met may samples and blanks be analyzed.

11.6.2 Inject 1.0 µL of the medium-level GC/MS crude oil/drilling fluid calibration standard into the GC instrument according to the procedures in Section 11.2. Verify that the linear regression curves for both TIC area and EIP areas are still valid using this continuing calibration standard.

11.6.3 After this analysis is complete, inject 1.0 µL of the 1.25 mg/mL SPTM (containing internal standard) into the GC instrument and verify the proper retention times are met (see Table 2).

11.6.4 Retention times—Retention time of the internal standard. The absolute retention time of the TCB internal standard should be within the range 21.0 ± 0.5 minutes. Relative retention times of the n-alkanes: The retention times of the n-alkanes relative to the TCB internal standard shall be similar to those given in Table 2.

12.0 Calculations

The concentration of oil in NAFs drilling fluids is computed relative to peak areas between C_8 and C_{13} (using the Total Area Integration method) or total peak areas from extracted ion profiles (using the Extracted Ion Profile Method). In either case, there is a measurable amount of peak area, even in clean drilling fluid samples, due to spurious peaks and electrometer ''noise'' that contributes to the total signal measured using either of the quantitation methods. In this procedure, a correction for this signal is applied, using the blank or clean sample correction technique described in American Society for Testing Materials (ASTM) Method D–3328–90, Comparison of Waterborne Oil by Gas Chromatography. In this method, the ''oil equivalents'' measured in a blank sample by total area gas chromatography are subtracted from that determined for a field sample to arrive at the most accurate measure of oil residue in the authentic sample.

12.1 Total Area Integration Method

12.1.1 Using C_8 to C_{13} TIC area, the TCB area in the clean NAF sample and the TIC linear regression curve, compute the oil equivalent concentration of the C_8 to C_{13} retention time range in the clean NAF. Note: The actual TIC area of the C_8 to C_{13} is equal to the C_8 to C_{13} area minus the area of the TCB.

12.1.2 Using the corresponding information for the authentic sample, compute the oil equivalent concentration of the C_8 to C_{13} retention time range in the authentic sample.

12.1.3 Calculate the concentration (% oil) of oil in the sample by subtracting the oil equivalent concentration (% oil) found in the clean NAF from the oil equivalent concentration (% oil) found in the authentic sample.

12.2 EIP Area Integration Method

12.2.1 Using either m/z 91 or 105 EIP areas, the TCB area in the clean NAF sample, and the appropriate EIP linear regression curve, compute the oil equivalent concentration of the in the clean NAF.

12.2.2 Using the corresponding information for the authentic sample, compute its oil equivalent concentration.

12.2.3 Calculate the concentration (% oil) of oil in the sample by subtracting the oil equivalent concentration (% oil) found in the clean NAF from the oil equivalent concentration (% oil) found in the authentic sample.

13.0 Method Performance

13.1 Specification in this method are adopted from EPA Method 1663, Differentiation of Diesel and Crude Oil by GC/FID (Reference 16.5).

13.2 Single laboratory method performance using an Internal Olefin (IO) drilling fluid fortified at 0.5% oil using a 35 API gravity oil was:

Precision and accuracy 94±4%
Accuracy interval—86.3% to 102%
Relative percent difference in duplicate analysis—6.2%

14.0 Pollution Prevention

14.1 The solvent used in this method poses little threat to the environment when recycled and managed properly.

15.0 Waste Management

15.1 It is the laboratory's responsibility to comply with all federal, state, and local regulations governing waste management, particularly the hazardous waste identification rules and land disposal restriction, and to protect the air, water, and land by minimizing and controlling all releases from fume hoods and bench operations. Compliance with all sewage discharge permits and regulations is also required.

15.2 All authentic samples (drilling fluids) failing the RPE (fluorescence) test (indicated by the presence of fluorescence) shall be retained and classified as contaminated samples. Treatment and ultimate fate of these samples is not outlined in this SOP.

15.3 For further information on waste management, consult ''The Waste Management Manual for Laboratory Personnel'', and ''Less is Better: Laboratory Chemical Management for Waste Reduction'', both available form the American Chemical Society's Department of Government Relations and Science Policy, 1155 16th Street NW, Washington, D.C. 20036.

16.0 References

16.1 Carcinogens—''Working With Carcinogens.'' Department of Health, Education, and Welfare, Public Health Service, Centers for Disease Control [available through National Technical Information Systems, 5285 Port Royal Road, Springfield, VA 22161, document no. PB–277256]: August 1977.

16.2 ''OSHA Safety and Health Standards, General Industry [29 CFR 1910], Revised.'' Occupational Safety and Health Administration, OSHA 2206. Washington, DC: January 1976.

16.3 ''Handbook of Analytical Quality Control in Water and Wastewater Laboratories.'' USEPA, EMSSL–CI, EPA–600/4–79–019. Cincinnati, OH: March 1979.

16.4 ''Method 1663, Differentiation of Diesel and Crude Oil by GC/FID, Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA 821–R–92–008, Office of Water Engineering and Analysis Division, Washington, DC: December 1992.

Appendix 6 to Subpart A of Part 435—Reverse Phase Extraction (RPE) Method for Detection of Oil Contamination in Non-Aqueous Drilling Fluids (NAF)

1.0 Scope and Application

1.1 This method is used for determination of crude or formation oil, or other petroleum oil contamination, in non-aqueous drilling fluids (NAFs).

1.2 This method is intended as a positive/negative test to determine a presence of crude oil in NAF prior to discharging drill cuttings from offshore production platforms.

1.3 This method is for use in the Environmental Protection Agency's (EPA's) survey and monitoring programs under the Clean Water Act, including monitoring of compliance with the Gulf of Mexico NPDES General Permit for monitoring of oil contamination in drilling fluids.

1.4 This method has been designed to show positive contamination for 5% of representative crude oils at a concentration of 0.1% in drilling fluid (vol/vol), 50% of representative crude oils at a concentration of 0.5%, and 95% of representative crude oils at a concentration of 1%.

1.5 Any modification of this method, beyond those expressly permitted, shall be considered a major modification subject to application and approval of alternate test procedures under 40 CFR Parts 136.4 and 136.5.

1.6 Each laboratory that uses this method must demonstrate the ability to generate acceptable results using the procedure in Section 9.2.

2.0 Summary of Method

2.1 An aliquot of drilling fluid is extracted using isopropyl alcohol.

2.2 The mixture is allowed to settle and then filtered to separate out residual solids.

2.3 An aliquot of the filtered extract is charged onto a reverse phase extraction (RPE) cartridge.

2.4 The cartridge is eluted with isopropyl alcohol.

2.5 Crude oil contaminates are retained on the cartridge and their presence (or absence) is detected based on observed fluorescence using a black light.

3.0 Definitions

3.1 A NAF is one in which the continuous phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhance mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

4.0 Interferences

4.1 Solvents, reagents, glassware, and other sample-processing hardware may yield artifacts that affect results. Specific selection of reagents and purification of solvents may be required.

4.2 All materials used in the analysis shall be demonstrated to be free from interferences under the conditions of analysis by running laboratory reagent blanks as described in Section 9.5.

5.0 Safety

5.1 The toxicity or carcinogenicity of each reagent used in this method has not been precisely determined; however, each chemical should be treated as a potential health hazard. Exposure to these chemicals should be reduced to the lowest possible level. Material Safety Data Sheets (MSDSs) should be available for all reagents.

5.2 Isopropyl alcohol is flammable and should be used in a well-ventilated area.

5.3 Unknown samples may contain high concentration of volatile toxic compounds. Sample containers should be opened in a hood and handled with gloves to prevent exposure. In addition, all sample preparation should be conducted in a well-ventilated area to limit the potential exposure to harmful contaminants. Drilling fluid samples should be handled with the same precautions used in the drilling fluid handling areas of the drilling rig.

5.4 This method does not address all safety issues associated with its use. The laboratory is responsible for maintaining a safe work environment and a current awareness file of OSHA regulations regarding the safe handling of the chemicals specified in this method. A reference file of material safety data sheets (MSDSs) should be available to all personnel involved in these analyses. Additional information on laboratory safety can be found in References 16.1–16.2.

6.0 Equipment and Supplies

Note: Brand names, suppliers, and part numbers are for illustrative purposes only. No endorsement is implied. Equivalent performance may be achieved using apparatus and materials other than those specified here, but demonstration of equivalent performance that meets the requirements of this method is the responsibility of the laboratory.

6.1 Sampling equipment.

6.1.1 Sample collection bottles/jars—New, pre-cleaned bottles/jars, lot-certified to be free of artifacts. Glass preferable, plastic acceptable, wide mouth approximately 1–L, with Teflon-lined screw cap.

6.2 Equipment for glassware cleaning.

6.2.1 Laboratory sink.

6.2.2 Oven—Capable of maintaining a temperature within ±5° C in the range of 100–250° C.

6.3 Equipment for sample extraction.

6.3.1 Vials—Glass, 25 mL and 4 mL, with Teflon-lined screw caps, baked at 200–250° C for 1-h minimum prior to use.

6.3.2 Gas-tight syringes—Glass, various sizes, 0.5 mL to 2.5 mL (if spiking of drilling fluids with oils is to occur).

6.3.3 Auto pipetters—various sizes, 0.1 mL, 0.5 mL, 1 to 5 mL delivery, and 10 mL delivery, with appropriate size disposable pipette tips, calibrated to within ±0.5%.

6.3.4 Glass stirring rod.

6.3.5 Vortex mixer.

6.3.6 Disposable syringes—Plastic, 5 mL.

6.3.7 Teflon syringe filter, 25-mm, 0.45µm pore size—Acrodisc® CR Teflon (or equivalent).

6.3.8 Reverse Phase Extraction C_{18} Cartridge—Waters Sep-Pak®Plus, C_{18} Cartridge, 360 mg of sorbent (or equivalent).

6.3.9 SPE vacuum manifold—Supelco Brand, 12 unit (or equivalent). Used as support for cartridge/syringe assembly only. Vacuum apparatus not required.

6.4 Equipment for fluorescence detection.

6.4.1 Black light—UV Lamp, Model UVG 11, Mineral Light Lamp, Shortwave, 254 nm, 15 volts, 60 Hz, 0.16 amps (or equivalent).

6.4.2 Black box—cartridge viewing area. A commercially available ultraviolet viewing cabinet with viewing lamp, or alternatively, a cardboard box or equivalent, approximately 14″x7.5″x7.5″ in size and painted flat black inside. Lamp positioned in fitted and sealed slot in center on top of box. Sample cartridges sit in a tray, ca. 6″ from lamp. Cardboard flaps cut on top panel and side of front panel for sample viewing and sample cartridge introduction, respectively.

6.4.3 Viewing platform for cartridges. Simple support (hand made vial tray—black in color) for cartridges so that they do not move during the fluorescence testing.

7.0 Reagents and Standards

7.1 Isopropyl alcohol—99% purity.

7.2 NAF—Appropriate NAF as sent from the supplier (has not been circulated downhole). Use the clean NAF corresponding to the NAF being used in the current drilling operation.

8.0 Sample Collection, Preservation, and Storage

8.1 Collect approximately one liter of representative sample (NAF, which has been circulated downhole) in a glass bottle or jar. Cover with a Teflon lined cap. To allow for a potential need to re-analyze and/or re-process the sample, it is recommended that a second sample aliquot be collected.

8.2 Label the sample appropriately.

8.3 All samples must be refrigerated at 0–4°C from the time of collection until extraction (40 CFR Part 136, Table II).

8.4 All samples must be analyzed within 28 days of the date and time of collection (40 CFR Part 136, Table II).

9.0 Quality Control

9.1 Each laboratory that uses this method is required to operate a formal quality assurance program (Reference 16.3). The minimum requirements of this program consist of an initial demonstration of laboratory capability, and ongoing analyses of blanks and spiked duplicates to assess accuracy and precision and to demonstrate continued performance. Each field sample is analyzed in duplicate to demonstrate representativeness.

9.1.1 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 9.2.

9.1.2 Preparation and analysis of a set of spiked duplicate samples to document accuracy and precision. The procedure for the preparation and analysis of these samples is described in Section 9.4.

9.1.3 Analyses of laboratory reagent blanks are required to demonstrate freedom from contamination. The procedure and criteria for preparation and analysis of a reagent blank are described in Section 9.5.

9.1.4 The laboratory should maintain records to define the quality of the data that is generated.

9.1.5 Accompanying QC for the determination of oil in NAF is required per analytical batch. An analytical batch is a set of samples extracted at the same time, to a maximum of 10 samples. Each analytical batch of 10 or fewer samples must be accompanied by a laboratory reagent blank (Section 9.5), corresponding NAF reference blanks (Section 9.6), a set of spiked duplicate samples blank (Section 9.4), and duplicate analysis of each field sample. If greater than 10 samples are to be extracted at one time, the samples must be separated into analytical batches of 10 or fewer samples.

9.2 Initial demonstration of laboratory capability. To demonstrate the capability to perform the test, the analyst should analyze two representative unused drilling fluids (e.g., internal olefin-based drilling fluid, vegetable ester-based drilling fluid), each prepared separately containing 0.1%, 1%, and 2% or a representative oil. Each drilling fluid/concentration combination will be analyzed 10 times, and successful demonstration will yield the following average results for the data set:

0.1% oil	1 %oil	2 %oil
Detected in <20% of samples	Detected in >75% of samples	Detected in <90% of samples.

9.3 Sample duplicates.

9.3.1 The laboratory must prepare and analyze (Section 11.2 and 11.4) each authentic sample in duplicate, from a given sampling site or, if for compliance monitoring, from a given discharge.

9.3.2 The duplicate samples must be compared versus the prepared corresponding NAF blank.

9.3.3 Prepare and analyze the duplicate samples according to procedures outlined in Section 11.

9.3.4 The results of the duplicate analyses are acceptable if each of the results give the same response (fluorescence or no fluorescence). If the results are different, sample non-homogenicity issues may be a concern. Prepare the samples again, ensuring a well-mixed sample prior to extraction. Analyze the samples once again.

9.3.5 If different results are obtained for the duplicate a second time, the analytical system is judged to be out of control and the problem shall be identified and corrected, and the samples reanalyzed.

9.4 Spiked duplicates—Laboratory prepared spiked duplicates are analyzed to demonstrate acceptable accuracy and precision.

9.4.1 Preparation and analysis of a set of spiked duplicate samples with each set of no more than 10 field samples is required to demonstrate method accuracy and precision and to monitor matrix interferences (interferences caused by the sample matrix). A field NAF sample expected to contain less than 0.5% crude oil (and documented to not fluoresce as part of the sample batch analysis) will be spiked with 1% (by volume) of suitable reference crude oil and analyzed as field samples, as described in Section 11. If no low-level drilling fluid is available, then the unused NAF can be used as the drilling fluid sample.

9.5 Laboratory reagent blanks—Laboratory reagent blanks are analyzed to demonstrate freedom from contamination.

9.5.1 A reagent blank is prepared by passing 4 mL of the isopropyl alcohol through a Teflon syringe filter and collecting the filtrate in a 4-mL glass vial. A Sep Pak® C_{18} cartridge is then preconditioned with 3 mL of isopropyl alcohol. A 0.5-mL aliquot of the filtered isopropyl alcohol is added to the syringe barrel along with 3.0 mL of isopropyl alcohol. The solvent is passed through the preconditioned Sep Pak® cartridge. An additional 2-mL of isopropyl alcohol is eluted through the cartridge. The cartridge is now considered the ''reagent blank'' cartridge and is ready for viewing (analysis). Check the reagent blank cartridge under the black light for fluorescence. If the isopropyl alcohol and filter are clean, no fluorescence will be observed.

9.5.2 If fluorescence is detected in the reagent blank cartridge, analysis of the samples is halted until the source of contamination is eliminated and a prepared reagent blank shows no fluorescence under a black light. All samples must be associated with an uncontaminated method blank before the results may be reported for regulatory compliance purposes.

9.6 NAF reference blanks—NAF reference blanks are prepared from the NAFs sent from the supplier (NAF that has not been circulated downhole) and used as the reference when viewing the fluorescence of the test samples.

9.6.1 A NAF reference blank is prepared identically to the authentic samples. Place a 0.1 mL aliquot of the ''clean'' NAF into a 25-mL glass vial. Add 10 mL of isopropyl alcohol to the vial. Cap the vial. Vortex the vial for approximately 10 sec. Allow the solids to settle for approximately 15 minutes. Using a 5-mL syringe, draw up 4 mL of the extract and filter it through a PTFE syringe filter, collecting the filtrate in a 4-mL glass vial. Precondition a Sep Pak® C_{18} cartridge with 3 mL of isopropyl alcohol. Add a 0.5-mL aliquot of the filtered extract to the syringe barrel along with 3.0 mL of isopropyl alcohol. Pass the extract and solvent through the preconditioned Sep Pak® cartridge. Pass an additional 2-mL of isopropyl alcohol through the cartridge. The cartridge is now considered the NAF blank cartridge and is ready for viewing (analysis). This cartridge is used as the reference cartridge for determining the absence or presence of fluorescence in all authentic drilling fluid samples that originate from the same NAF. That is, the specific NAF reference blank cartridge is put under the black light along with a prepared cartridge of an authentic sample originating from the same NAF material. The fluorescence or absence of fluorescence in the authentic sample cartridge is determined relative to the NAF reference cartridge.

10.0 Calibration and Standardization

10.1 Calibration and standardization methods are not employed for this procedure.

11.0 Procedure

This method is a screening-level test. Precise and accurate results can be obtained only by strict adherence to all details.

11.1 Preparation of the analytical batch.

11.1.1 Bring the analytical batch of samples to room temperature.

11.1.2 Using a large glass stirring rod, mix the authentic sample thoroughly.

11.1.3 Using a large glass stirring rod, mix the clean NAF (sent from the supplier) thoroughly.

11.2 Extraction.

11.2.1 Using an automatic positive displacement pipetter and a disposable pipette tip transfer 0.1-mL of the authentic sample into a 25-mL vial.

11.2.2 Using an automatic pipetter and a disposable pipette tip dispense a 10-mL aliquot of solvent grade isopropyl alcohol (IPA) into the 25 mL vial.

11.2.3 Cap the vial and vortex the vial for ca. 10–15 seconds.

11.2.4 Let the sample extract stand for approximately 5 minutes, allowing the solids to separate.

11.2.5 Using a 5-mL disposable plastic syringe remove 4 mL of the extract from the 25-mL vial.

11.2.6 Filter 4 mL of extract through a Teflon syringe filter (25-mm diameter, 0.45µm pore size), collecting the filtrate in a labeled 4-mL vial.

11.2.7 Dispose of the PFTE syringe filter.

11.2.8 Using a black permanent marker, label a Sep Pak® C_{18} cartridge with the sample identification.

11.2.9 Place the labeled Sep Pak® C_{18} cartridge onto the head of a SPE vacuum manifold.

11.2.10 Using a 5-mL disposable plastic syringe, draw up exactly 3-mL (air free) of isopropyl alcohol.

11.2.11 Attach the syringe tip to the top of the C_{18} cartridge.

11.2.12 Condition the C_{18} cartridge with the 3-mL of isopropyl alcohol by depressing the plunger slowly. Note: Depress the plunger just to the point when no liquid remains in the syringe barrel. Do not force air through the cartridge. Collect the eluate in a waste vial.

11.2.13 Remove the syringe temporarily from the top of the cartridge, then remove the plunger, and finally reattach the syringe barrel to the top of the C_{18} cartridge.

11.2.14 Using automatic pipetters and disposable pipette tips, transfer 0.5 mL of the filtered extract into the syringe barrel, followed by a 3.0-mL transfer of isopropyl alcohol to the syringe barrel.

11.2.15 Insert the plunger and slowly depress it to pass only the extract and solvent through the preconditioned C_{18} cartridge. Note: Depress the plunger just to the point when no liquid remains in the syringe barrel. Do not force air through the cartridge. Collect the eluate in a waste vial.

11.2.16 Remove the syringe temporarily from the top of the cartridge, then remove the plunger, and finally reattach the syringe barrel to the top of the C_{18} cartridge.

11.2.17 Using an automatic pipetter and disposable pipette tip, transfer 2.0 mL of isopropyl alcohol to the syringe barrel.

11.2.18 Insert the plunger and slowly depress it to pass the solvent through the C_{18} cartridge. Note: Depress the plunger just to the point when no liquid remains in the syringe barrel. Do not force air through the cartridge. Collect the eluate in a waste vial.

11.2.19 Remove the syringe and labeled C_{18} cartridge from the top of the SPE vacuum manifold.

11.2.20 Prepare a reagent blank according to the procedures outlined in Section 9.5.

11.2.21 Prepare the necessary NAF reference blanks for each type of NAF encountered in the field samples according to the procedures outlined in Section 9.6.

11.3 Reagent blank fluorescence testing.

11.3.1 Place the reagent blank cartridge in a black box, under a black light.

11.3.2 Determine the presence or absence of fluorescence for the reagent blank cartridge. If fluorescence is detected in the blank, analysis of the samples is halted until the source of contamination is eliminated and a prepared reagent blank shows no fluorescence under a black light. All samples must be associated with an uncontaminated method blank before the results may be reported for regulatory compliance purposes.

11.4 Sample fluorescence testing.

11.4.1 Place the respective NAF reference blank (Section 9.6) onto the tray inside the black box.

11.4.2 Place the authentic field sample cartridge (derived from the same NAF as the NAF reference blank) onto the tray, adjacent and to the right of the NAF reference blank.

11.4.3 Turn on the black light.

11.4.4 Observe the presence or absence of fluorescence for the sample cartridge (in right position) relative to the NAF reference blank.

11.4.5 The presence of fluorescence indicates the detection of crude oil contamination. The absence of fluorescence in the sample cartridge indicates that the drilling fluid is ''clean''.

12.0 Data Analysis and Calculations

Specific data analysis techniques and calculations are not performed in this SOP.

13.0 Method Performance

This method was validated through a single laboratory study, conducted with rigorous statistical experimental design and interpretation (Reference 16.4).

14.0 Pollution Prevention

14.1 The solvent used in this method poses little threat to the environment when recycled and managed properly.

15.0 Waste Management

15.1 It is the laboratory's responsibility to comply with all Federal, State, and local regulations governing waste management, particularly the hazardous waste identification rules and land disposal restriction, and to protect the air, water, and land by minimizing and controlling all releases from bench operations. Compliance with all sewage discharge permits and regulations is also required.

15.2 All authentic samples (drilling fluids) failing the fluorescence test (indicated by the presence of fluorescence) shall be retained and classified as contaminated samples. Treatment and ultimate fate of these samples is not outlined in this SOP.

15.3 For further information on waste management, consult ''The Waste Management Manual for Laboratory Personnel,'' and ''Less is Better: Laboratory Chemical Management for Waste Reduction,'' both available from the American Chemical Society's Department of Government Relations and Science Policy, 1155 16th Street, NW, Washington, DC 20036.

16.0 References

16.1 ''Carcinogen—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. 77–206, August 1977.

16.2 ''OSHA Safety and Health Standards, General Industry,'' (29 CFR 1910), Occupational Safety and Health Administration, OSHA 2206 (Revised, January 1976).

16.3 ''Handbook of Analytical Quality Control in Water and Wastewater Laboratories,'' USEPA, EMSL-Ci, Cincinnati, OH 45268, EPA–600/4–79–019, March 1979.

16.4 Report of the Laboratory Evaluation of Static Sheen Test Replacements—Reverse Phase Extraction (RPE) Method for Detecting Oil Contamination in Synthetic Based Mud (SBM). October 1998. Available from API, 1220 L Street, NW, Washington, DC 20005–4070, 202–682–8000.

Appendix 7 to Subpart A of Part 435—API Recommended Practice 13B–2

1. Description

a. This procedure is specifically intended to measure the amount of oleaginous base fluid from cuttings generated during a drilling operation. It is a retort test which measures all oily material (base fluid) and water released from a cuttings sample when heated in a calibrated and properly operating ''Retort'' instrument.

b. In this retort test a known weight of cuttings is heated in the retort chamber to vaporize the liquids associated with the sample. The base fluid and water vapors are then condensed, collected, and measured in a precision graduated receiver.

Note: Obtaining a representative sample requires special attention to the details of sample handling (location, method, frequency). The sampling procedure in a given area may be specified by local or governmental rules.

2. Equipment

a. Retort instrument—The recommended retort instrument has a 50-cm^3 volume with an external heating jacket.

Retort Specifications:

1. Retort assembly—retort body, cup and lid.

(a) Material: 303 stainless steel or equivalent.

(b) Volume: Retort cup with lid.

Cup Volume: 50-cm^3

Precision: ±0.25-cm^3

2. Condenser—capable of cooling the oil and water vapors below their liquification temperature.

3. Heating jacket—nominal 350 watts.

4. Temperature control—capable of limiting temperature of retort to 930 ±70°F (500 ±38°C).

b. Liquid receiver (10-cm^3, 20-cm^3, or 50-cm^3)—the 10-cm^3 and 20-cm^3 receivers are specially designed cylindrical glassware with rounded bottom to facilitate cleaning and funnel-shaped top to catch falling drops.

1. Receiver specifications.

Total volume: 10-cm^3	20-cm^3	50-cm^3	
Precision (0 to 100%)	±0.05cm^3	±0.05cm^3	±0.05cm^3 nom.
Outside diameter	10-mm	13-mm	

Wall thickness	1.5±0.1mm	1.2±0.1mm	
Frequency of graduation marks (0 to 100%)	0.10cm³	0.10cm³	1.0cm³
Calibration	To contain ''TC''	20°C	
Scale	cm³	cm³	cm³

Note: Verification of receiver volume. The receiver volume should be verified gravimetrically. The procedure and calculations are in Par. 5.

2. Material—Pyrex® or equivalent glass.
c. Toploading balance—capable of weighing 2000 g and precision of 0.1g.
d. Fine steel wool (No. 000)—for packing retort body.
e. Thread sealant lubricant: high temperature lubricant, e.g. Never-Seez® or equivalent.
f. Pipe cleaners—to clean condenser and retort stem.
g. Brush—to clean receivers.
h. Retort spatula—to clean retort cup.
i. Corkscrew—to remove spent steel wool.

3. Procedure

a. Clean and dry the retort assembly and condenser.
b. Pack the retort body with steel wool.
c. Apply lubricant/sealant to threads of retort cup and retort stem.
d. Weigh and record the total mass of the retort cup, lid, and retort body with steel wool. This is mass (A), grams.
e. Collect a representative cuttings sample. (See Note in Par. 1)
f. Partially fill the retort cup with cuttings and place the lid on the cup.
g. Screw the retort cup (with lid) onto the retort body, weigh and record the total mass. This is mass (B), grams.
h. Attach the condenser. Place the retort assembly into the heating jacket.
i. Weigh and record the mass of the clean and dry liquid receiver. This is mass (C), grams. Place the receiver below condenser outlet.
j. Turn on the retort. Allow it to run a minimum of 1 hour.

Note: If solids boil over into receiver, the test must be rerun. Pack the retort body with a greater amount of steel wool and repeat the test.

k. Remove the liquid receiver. Allow it to cool. Record the volume of water recovered. This is (V), cm³.

Note: If an emulsion interface is present between the oil and water phases, heating the interface may break the emulsion. As a suggestion, remove the retort assembly from the heating jacket by grasping the condenser. Carefully heat the receiver along the emulsion band by gently touching the receiver for short intervals with the hot retort assembly. Avoid boiling the liquids. After the emulsion interface is broken, allow the liquid receiver to cool. Read the water volume at the lowest point of the meniscus.

l. Weigh and record the mass of the receiver and its liquid contents (oil plus water). This is mass (D), grams.
m. Turn off the retort. Remove the retort assembly and condenser from the heating jacket and allow them to cool. Remove the condenser.
n. Weigh and record the mass of the cooled retort assembly without the condenser. This is mass (E), grams.
o. Clean the retort assembly and condenser.

4. Calculations

a. Calculate the mass of oil (base fluid) from the cuttings as follows:
1. Mass of the wet cuttings sample (M_D) equals the mass of the retort assembly (A).

$$\mathbf{M_w = B–A \qquad (a)}$$

2. Mass of the dry retorted cuttings (M_D) equals the mass of the cooled retort assembly (E) minus the mass of the empty retort assembly (A).

$$\mathbf{M_D = E–A \qquad (b)}$$

3. Mass of the base fluid (M_{BF}) equals the mass of the liquid receiver with its contents (D) minus the sum of the mass of the dry receiver (C) and the mass of the water (V).

$$\mathbf{M_{BF} = D—(C+V) \qquad (c)}$$

Note: Assuming the density of water is 1 g/cm³, the volume of water is equivalent to the mass of the water.

b. Mass balance requirement:
The sum of M_D, M_{BF}, and V should be within 5% of the mass of the wet sample.

$$\mathbf{(M_D + M_{BF} + V)/M_w = 0.95 \text{ to } 1.05}$$

The procedure should be repeated if this requirement is not met.
c. Reporting oil from cuttings:
1. Assume that all oil recovered is NAF base fluid.
2. The weight percent base fluid retained on the cuttings (%BF) is equal to 100 times the mass of the base fluid (M_{BF}) divided by the mass of the wet cuttings sample (M_w).

$$\mathbf{\%BF = (M_{BF}/M_w) \times 100}$$

3. The %BF is determined for all cuttings wastestreams, including fines, and is associated with a respective length of hole drilled (L in feet) and bit diameter (d in inches).
4. Any cuttings or fines that are retained for no discharge are included in the weighted average with a %BF value of zero.
5. Each cuttings or fines sample corresponds to a wastestream fraction X_w (unitless), and should be representative for a certain length of hole drilled L (feet), using a drill bit of a specific diameter d (inches). The wastestream fraction (X_w) is the weight of discharge in each stream calculated as a fraction of total cuttings (including fines) discharge. The weighted average of %BF for the entire wastestream is equal to the sum of %BF times the wastestream fraction (X_w) times the length of hole (L) at given diameter times the square of the diameter (d^2) divided by the sum of the wastestream fraction (X_w) times the length of the hole (L) at given a diameter times the square of the diameter (d^2).

$$\mathbf{\text{Weighted average of } \%BF = \Sigma\,(\%BF \times X_w \times L \times d^2)/\Sigma\,(X_w \times L \times d^2)}$$

5. Verification of Liquid Receiver Volume

a. This procedure is used to verify that the liquid receiver meets specifications stated in Par. 2b.
b. Equipment:
1. Distilled water.
2. Glass thermometer—to measure ambient temperature ±0.1°F (±0.1°C).

3. Toploading balance—precision of 0.1 g.
4. Syringe or pipette—10-cm^3 or larger.
c. Procedure:
1. Allow receiver and distilled water to reach ambient temperature. Record temperature.
2. Place the clean, empty receiver with its base on the balance and tare to zero.
3. While the receiver is on the balance, fill it to the various graduation marks (2, 4, 6, 8, 10-cm^3 for the 10-cm^3 receiver, 4, 8, 12, 16, 20-cm^3 for the 20-cm^3, and 10, 20, 30, 40, and 50-cm^3 for the 50-cm^3 receiver) with distilled water. Using a pipette or syringe, carefully fill the receiver to the desired graduation mark without leaving water droplets on the walls of the receiver.
4. Record weights for the incremental volumes, IV, of water at the specific graduation marks, W_{IV}, grams.
d. Calculation:
1. Calculate volume of the receiver at each mark, V_{MARK}, using density of water Table 1.

$$V_{MARK} = (W_{IV}, g)/(\text{Density of Water, g/cm}^3) \qquad (a)$$

TABLE 1.—DENSITY OF WATER

°F	°C	Density, g/cm^3
59.0	15.0	0.9991
59.9	15.5	0.9991
60.8	16.0	0.9990
61.7	16.5	0.9989
62.6	17.0	0.9988
63.5	17.5	0.9987
64.4	18.0	0.9986
65.3	18.5	0.9985
66.2	19.0	0.9984
67.1	19.5	0.9983
68.0	20.0	0.9982
68.9	20.5	0.9981
69.8	21.0	0.9980
70.7	21.5	0.9979
71.6	22.0	0.9977
72.5	22.5	0.9976
73.4	23.0	0.9975
74.3	23.5	0.9974
75.2	24.0	0.9973
76.1	24.5	0.9971
77.0	25.0	0.9970
77.9	25.5	0.9969
78.8	26.0	0.9968
79.7	26.5	0.9966
80.6	27.0	0.9965
81.5	27.5	0.9964
82.4	28.0	0.9962
83.3	28.5	0.9961
84.2	29.0	0.9959
85.1	29.5	0.9958
86.0	30.0	0.9956
86.9	30.5	0.9955
87.8	31.0	0.9953
88.7	31.5	0.9952
89.6	32.0	0.9950
90.5	32.5	0.9949
91.4	33.0	0.9947
92.3	33.5	0.9945
93.2	34.0	0.9944
94.1	34.5	0.9942
95.0	35.0	0.9940

Addendum A—Sampling of Cuttings Discharge Streams for Use With API Recommended Practice 13B–2

Sampling Locations

1. Each individual discharge stream should be sampled and tested. These may include the discharge streams from the primary shakers, the secondary shakers, and any other cuttings separation device, such as a centrifuge, whose discharge is dumped directly to the environment. The weight of discharge in each stream should be measured and calculated as a fraction of total cuttings discharge, X_w. The wastestream fraction, X_W, is used in the weighted average percent base fluid in cuttings. Each sample should report the respective linear feet of hole drilled represented by this sample (L in feet), and the drill bit diameter (d in inches).

2. It is essential that the samples be representative of the discharge stream. Sampling should be conducted to avoid the serious consequences of error, i.e., bias or inaccuracy. They should be caught near the point of origin and before the solids and liquid fractions of the stream have a chance to separate from one another. For example, shaker samples should be taken as the cuttings are coming off the shaker and not from of a holding container downstream where separation of larger particles from the liquid can take place.

3. A simple schematic diagram of the solids control system being used shall be provided indicating where the samples were taken.

Sample Size and Handling

1. The sample size should be about one quart (or liter). A viscosity cup is a suitable and usually available container for catching the sample. The sample can be transferred to a quart jar if the retort measurement is not going to be made immediately. Mark the container to clearly identify each sample.

2. Before pouring sample into retort cup, it should be made homogeneous by gentle mixing such as hand stirring or shaking of a jar. The bottom of the container should be examined to be sure that solids are not sticking to it. For best results, the sample should be run immediately after stirring and no more than two hours after catching the sample. Do not discard sample before weight percent synthetic has been calculated and results are within prescribed limits noted in the analytical method. Rerunning the retort test may be necessary.

Type of Sample and Sampling Frequency

3. Samples should represent steady state drilling operations after obtaining bottoms-up. They should be time lagged to obtain the actual depth of origin of the formation cuttings rather than the drilling depth at the time the sample was caught. Samples should not be taken at any time when there are not newly generated formation cuttings in the discharge stream.

4. During drilling operations, at least one sample per day should be caught and tested. In fast drilling, a sample should be caught for every 500 feet of hole drilled up to a maximum of three samples per day.

Subpart D—Coastal Subcategory

8. Section 435.41 is revised to read as follows:

§ 435.41 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided in this section, the general definitions, abbreviations and methods of analysis set forth in 40 CFR part 401 shall apply to this subpart.

(b) The term *average of daily values for 30 consecutive days* shall be the average of the daily values obtained during any 30 consecutive day period.

(c) The term *base fluid retained on cuttings* shall refer to American Petroleum Institute Recommended Practice 13B–2 supplemented with the specifications, sampling methods, and averaging of the retention values provided in Appendix 7 of 40 CFR part 435, subpart A.

(d) The term *biodegradation rate* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to the test procedure presented in appendix 4 of 40 CFR part 435, subpart A.

(e) The term *Cook Inlet* refers to coastal locations north of the line between Cape Douglas on the West and Port Chatham on the east.

(f) The term *daily values* as applied to produced water effluent limitations and NSPS shall refer to the daily measurements used to assess compliance with the maximum for any one day.

(g) The term *deck drainage* shall refer to any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this subpart.

(h) The term *percent degraded at 120 days* shall refer to the concentration (milligrams/kilogram dry sediment) of the base fluid in sediment relative to the initial concentration of base fluid in sediment at the start of the test on day zero.

(i) The term *percent stock base fluid degraded at 120 days minus percent C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero* shall mean that the percent base fluid degraded at 120 days of any single sample of base fluid shall not be less than the percent C_{16}-C_{18} internal olefin degraded at 120 days as a control standard.

(j) The term *development facility* shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling of productive wells.

(k) The term *dewatering effluent* means wastewater from drilling fluids and drill cuttings dewatering activities (including but not limited to reserve pits or other tanks or vessels, and chemical or mechanical treatment occurring during the drilling solids separation/recycle/disposal process).

(l) The term *diesel oil* shall refer to the grade of distillate fuel oil, as specified in the American Society for Testing and Materials Standard Specification for Diesel Fuel Oils D975–91, that is typically used as the continuous phase in conventional oil-based drilling fluids. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103. Copies may be inspected at the Office of the Federal Register, 800 North Capitol Street, NW, Suite 700, Washington, DC. A copy may also be inspected at EPA's Water Docket, 401 M Street SW., Washington, DC 20460.

(m) The term *domestic waste* shall refer to materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to this subpart.

(n) The term *drill cuttings* shall refer to the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid.

(o) The term *drilling fluid* refers to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. Classes of drilling fluids are:

(1) A water-based drilling fluid has water or a water miscible fluid as the continuous phase and the suspending medium for solids, whether or not oil is present.

(2) A non-aqueous drilling fluid is one in which the continuous phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhanced mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

(3) An oil-based drilling fluid has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase. Oil-based drilling fluids are a subset of non-aqueous drilling fluids.

(4) An enhanced mineral oil-based drilling fluid has an enhanced mineral oil as its continuous phase with water as the dispersed phase. Enhanced mineral oil-based drilling fluids are a subset of non-aqueous drilling fluids.

(5) A synthetic-based drilling fluid has a synthetic material as its continuous phase with water as the dispersed phase. Synthetic-based drilling fluids are a subset of non-aqueous drilling fluids.

(p) The term *enhanced mineral oil* as applied to enhanced mineral oil-based drilling fluid means a petroleum distillate which has been highly purified and is distinguished from diesel oil and conventional mineral oil in having a lower polycyclic aromatic hydrocarbon (PAH) content. Typically, conventional mineral oils have a PAH content on the order of 0.35 weight percent expressed as phenanthrene, whereas enhanced mineral oils typically have a PAH content of 0.001 or lower weight percent PAH expressed as phenanthrene.

(q) The term *exploratory facility* shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

(r) The term *no discharge of formation oil* shall mean that cuttings contaminated with non-aqueous drilling fluids (NAFs) may not be discharged if the NAFs contain formation oil, as determined by the GC/MS baseline

method as defined in appendix 5 to 40 CFR part 435, subpart A, to be applied before NAFs are shipped offshore for use, or the RPE method as defined in appendix 6 to 40 CFR part 435, subpart A, to be applied at the point of discharge. At the discretion of the permittee, detection of formation oil by the RPE method may be assured by the GC/MS method, and the results of the GC/MS method shall supercede those of the RPE method.

(s) The term *garbage* means all kinds of victual, domestic, and operational waste, excluding fresh fish and parts thereof, generated during the normal operation of coastal oil and gas facility and liable to be disposed of continuously or periodically, except dishwater, graywater, and those substances that are defined or listed in other Annexes to MARPOL 73/78. A copy of MARPOL may be inspected at EPA's Water Docket; 401 M Street SW, Washington DC 20460

(t) The term *maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the maximum concentration allowed as measured in any single sample of the barite for determination of cadmium and mercury content, or as measured in any single sample of base fluid for determination of PAH content.

(u) The term *maximum weighted average for well* for BAT effluent limitations and NSPS for base fluid retained on cuttings shall mean the weighted average base fluid retention as determined by API RP 13B–2, using the methods and averaging calculations presented in appendix 7 of 40 CFR part 435, subpart A.

(v) The term *maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS for oil and grease in produced water shall mean the maximum concentration allowed as measured by the average of four grab samples collected over a 24-hour period that are analyzed separately. Alternatively, for BAT and NSPS the maximum concentration allowed may be determined on the basis of physical composition of the four grab samples prior to a single analysis.

(w) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the minimum 96-hour LC_{50} value allowed as measured in any single sample of the discharged waste stream. The term minimum as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes shall mean the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(x) The term *M9IM* shall mean those offshore facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(y) The term *M10* shall mean those offshore facilities continuously manned by ten (10) or more persons.

(z)(1) The term *new source* means any facility or activity of this subcategory that meets the definition of ''new source'' under 40 CFR 122.2 and meets the criteria for determination of new sources under 40 CFR 122.29(b) applied consistently with all of the following definitions:

(i) The term *water area* as used in the term ''site'' in 40 CFR 122.29 and 122.2 shall mean the water area and water body floor beneath any exploratory, development, or production facility where such facility is conducting its exploratory, development or production activities.

(ii) The term *significant site preparation work* as used in 40 CFR 122.29 shall mean the process of surveying, clearing or preparing an area of the water body floor for the purpose of constructing or placing a development or production facility on or over the site.

(2) ''New source'' does not include facilities covered by an existing NPDES permit immediately prior to the effective date of these guidelines pending EPA issuance of a new source NPDES permit.

(aa) The term *no discharge of free oil* shall mean that waste streams may not be discharged that contain free oil as evidenced by the monitoring method specified for that particular stream, e.g., deck drainage or miscellaneous discharges cannot be discharged when they would cause a film or sheen upon or discoloration of the surface of the receiving water; drilling fluids or cuttings may not be discharged when they fail the static sheen test defined in appendix 1 to 40 CFR part 435, subpart A.

(bb) The term *produced sand* shall refer to slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.

(cc) The term *produced water* shall refer to the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

(dd) The term *production facility* shall mean any fixed or mobile structure subject to this subpart that is either engaged in well completion or used for active recovery of hydrocarbons from producing formations. It includes facilities that are engaged in hydrocarbon fluids separation even if located separately from wellheads.

(ee) The term *sanitary waste* shall refer to human body waste discharged from toilets and urinals located within facilities subject to this subpart.

(ff) The term *sediment toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to ASTM E1367–92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods (Available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in appendix 3 of 40 CFR part 435, subpart A.

(gg) The term *static sheen test* shall refer to the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the static sheen test is presented in appendix 1 to 40 CFR part 435, subpart A.

(hh) The term *synthetic material* as applied to synthetic-based drilling fluid means material produced by the reaction of specific purified chemical feedstock, as opposed to the traditional base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes. Physical separation processes include fractionation and distillation and/or minor chemical reactions such as cracking and hydro processing. Since they are synthesized by the reaction of purified compounds, synthetic materials suitable for use in drilling fluids are typically free of polycyclic aromatic hydrocarbons (PAH's) but are sometimes found to contain levels of PAH up to 0.001 weight percent PAH expressed as phenanthrene. Poly(alpha olefins) and vegetable esters are two examples of synthetic materials suitable for use by the oil and gas extraction industry in formulating drilling fluids. Poly(alpha olefins) are synthesized from the polymerization (dimerization, trimerization, tetramerization, and higher oligomerization) of purified straight-chain hydrocarbons such as C_6–C_{14} alpha olefins. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. The mention of

these two branches of synthetic fluid base materials is to provide examples, and is not meant to exclude other synthetic materials that are either in current use or may be used in the future. A synthetic-based drilling fluid may include a combination of synthetic materials.

(ii) The term *SPP toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to the bioassay test procedure presented in appendix 2 of 40 CFR part 435, subpart A.

(jj) The term *well completion fluids* shall refer to salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.

(kk) The term *well treatment fluids* shall refer to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(ll) The term *workover fluids* shall refer to salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(mm) The term *10-day LC_{50}* shall refer to the concentration (milligrams/kilogram dry sediment) of the base fluid in sediment that is lethal to 50 percent of the test organisms exposed to that concentration of the base fluids after 10-days of constant exposure.

(nn) The term *10-day LC_{50} of stock base fluid minus 10-day LC_{50} of C_{16}-C_{18} internal olefin shall not be less than zero* shall mean that the 10-day LC_{50} of any single sample of the base fluid shall not be less than the LC_{50} of C_{16}-C_{18} internal olefin as a control standard.

(oo) The term *96-hour LC_{50}* shall refer to the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

9. In § 435.42 the table is amended by removing the entries ''Drilling fluids'' and ''Drill cuttings'' and by adding new entries (after ''Deck drainage'') for ''Water based'' and ''Non-aqueous'' to read as follows:

§ 435.42 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

* * * * *

BPT EFFLUENT LIMITATIONS—OIL AND GREASE

[In milligrams per liter]

Pollutant parameter waste source	Maximum for any 1 day	Average of values for 30 consecutive days shall not exceed	Residual chlorine minimum for any 1 day
* * * *	*	*	*
Water-Based:			
Drilling fluid	(1)	(1)	NA
Drill cuttings	(1)	(1)	NA
Non-aqueous:			
Drilling fluid	No discharge	No discharge	NA
Drill cuttings	(1)	(1)	NA
* * * *	*	*	*

[1] No discharge of free oil.

* * * * *

10. In § 435.43 the table is amended by revising entry B under the entry for ''Drilling fluids, drill cuttings, and dewatering effluent'' and by revising footnote 4 and adding footnotes 5–9 to read as follows:

§ 435.43 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

* * * * *

BAT EFFLUENT LIMITATIONS

Stream	Pollutant parameter	BAT effluent limitations
* * * *	*	*
Drilling Fluids, Drill Cuttings, and Dewatering Effluent:[1]		
* * * *	*	*
(B) Cook Inlet:		
Water-based drilling fluids, drill cuttings and dewatering effluent.	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP shall be 3 percent by volume.[4]
	Free Oil[2]	No discharge.
	Diesel Oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.

BAT EFFLUENT LIMITATIONS—Continued

Stream	Pollutant parameter	BAT effluent limitations
Non-aqueous drilling fluids and dewatering effluent.	.....	No discharge.
Cuttings associated with non-aqueous drilling fluids		
Stock Limitations	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Polynuclear Aromatic Hydrocarbons (PAH).	Maximum 10 ppm wt. PAH based on phenanthrene/wt. of stock base fluid.[5]
	Sediment Toxicity	10-day LC_{50} of stock base fluid minus 10-day LC_{50} of C_{16}-C_{18} internal olefin shall not be less than zero.[6]
	Biodegradation Rate	Percent stock base fluid degraded at 120 days minus percent C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero.[7]
Discharge Limitations	Diesel oil	No discharge.
	Formation Oil	No discharge.[8]
	Base fluid retained on cuttings	Maximum weighted average for well shall be 10.2 percent.[9]

* * * * * * *

[1] BAT limitations for dewatering effluent are applicable prospectively. BAT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

[2] As determined by the static sheen test (see appendix 1 to 40 CFR part 435, subpart A).

* * * * * * *

[4] As determined by the suspended particulate phase toxicity test (see appendix 2 of 40 CFR part 435, subpart A).

[5] As determined by EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector in Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA–821–R–92–008 [Incorporated by reference and available from National Technical Information Service (NTIS) (703/605–6000)]

[6] As determined by ASTM E1367–92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods (Incorporated by reference and available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in appendix 3 of 40 CFR part 435, subpart A.

[7] As determined by the biodegradation test (see appendix 4 to 40 CFR part 435, subpart A).

[8] As determined by the GC/MS baseline and assurance method (see appendix 5 to 40 CFR part 435, subpart A), and by the RPE method applied to drilling fluid removed from cuttings at primary shale shakers (see appendix 6 to 40 CFR part 435, subpart A).

[9] Maximum permissible retention of base fluid on wet cuttings averaged over drill intervals using non-aqueous drilling fluids as determined by retort method (see appendix 7 to 40 CFR part 435, subpart A).

11. In § 435.44 the table is amended by revising the entry for ''Cook Inlet'' under the entry for ''Drilling fluids and drill cuttings and dewatering effluent'' as follows:

§ 435.44 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT).

* * * * *

BCT EFFLUENT LIMITATIONS

Stream	Pollutant parameter	BCT effluent limitations
* * * * * * *		
Drilling Fluids and Drill Cuttings and Dewatering Effluent:[1]		
* * * * * * *		
Cook Inlet:		
Water-based drilling fluid, drill cuttings, and dewatering effluent	Free oil	No discharge.[2]
Non-aqueous drilling fluids and dewatering effluent	.....	No discharge.
Cuttings associated with non-aqueous drilling fluids	Free oil	No discharge.[2]
* * * * * * *		

[1] BCT limitations for dewatering effluent are applicable prospectively. BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

[2] As determined by the static sheen test (see Appendix 1 to 40 CFR Part 435, Subpart A).

* * * * *

12. In § 435.45 the table is amended by revising entry B under the entry for ''Drilling fluids, drill cuttings, and dewatering effluent'' and by revising footnote 4 and adding footnotes 5–9 to read as follows:

§ 435.45 Standards of performance for new sources (NSPS).

NSPS EFFLUENT LIMITATIONS

Stream	Pollutant parameter	NSPS effluent limitations
Drilling Fluids, Drill Cuttings and Dewatering Effluent:[1]		
* * * * * * *		
(B) Cook Inlet:		
Water-based drilling fluids, drill cuttings and dewatering effluent.	Free oil	No discharge [2]
	Diesel oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	SPP Toxicity	Minimum 96-hour LC50 of the SPP shall be 3% by volume.[4]
Non-aqueous drilling fluids and dewatering effluent.		No discharge.
Cuttings associated with non-aqueous drilling fluids		
Stock Limitations	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Polynuclear Aromatic Hydrocarbons (PAH).	Maximum 10 ppm wt. PAH based on phenanthrene/wt. of stock base fluid.[5]
	Sediment Toxicity	10-day LC_{50} of stock base fluid minus 10-day LC_{50} of C_{16}-C_{18} internal olefin shall not be less than zero.[6]
	Biodegradation Rate	Percent stock base fluid degraded at 120 days minus percent C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero.[7]
Discharge Limitations	Diesel oil	No discharge.
	Free oil	No discharge.[2]
	Formation oil	No discharge.[8]
	Base fluid retained or cuttings	Maximum weighted average for well shall be 10.2 percent.[9]
* * * * * * *		

[1] NSPS limitations for dewatering effluent are applicable prospectively. NSPS limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

[2] As determined by the static sheen test (see appendix 1 to 40 CFR part 435, subpart A).

[6] * * * * * * *

[4] As determined by the suspended particulate phase toxicity test (see appendix 2 of 40 CFR part 435, subpart A).

[5] As determined by EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector in Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA–821–R–92–008 [Incorporated by reference and available from National Technical Information Service (NTIS) (703/605–6000)].

[6] As determined by ASTM E1367–92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods (Incorporated by reference and available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in appendix 3 of 40 CFR part 435, subpart A.

[7] As determined by the biodegradation test (see appendix 4 to 40 CFR part 435, subpart A).

[8] As determined by the GC/MS baseline and assurance method (see appendix 5 to 40 CFR part 435, subpart A), and by the RPE method applied to drilling fluid removed from cuttings at primary shale shakers (see appendix 6 to 40 CFR part 435, subpart A).

[9] Maximum permissible retention of base fluid on wet cuttings averaged over drill intervals using non-aqueous drilling fluids as determined by retort method (see appendix 7 to 40 CFR part 435, subpart A).

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