ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 435

[FRL-4537-1]

RIN 2040-AA12

Oil and Gas Extraction Point Source Category; Offshore Subcategory Effluent Limitations Guidelines and New Source Performance Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes effluent limitations guidelines and new source performance standards limiting the discharge of pollutants to waters of the United States from the offshore subcategory of the oil and gas extraction point source category. This rule is promulgated under authority granted to EPA by the Clean Water Act and is required by consent decree in *NRDC* v. *Reilly*, D. D.C. No. 79-3442 (JHP).

The regulation establishes effluent limitations guidelines attainable by the application of the "best available technology economically achievable" (BAT) and "best conventional pollutant control technology" (BCT), and establishes "new source performance standards" (NSPS) attainable by the application of the "best available demonstrated technology." The existing effluent limitations guidelines based on the achievement of the "best practicable control technology currently available" (BPT) are not being changed by this regulation. Since offshore oil and gas facilities currently do not discharge into publicly owned treatment works (POTWs), pretreatment standards are not included in this regulation.

DATES: The regulation shall become effective April 5, 1993.

The compliance date for NSPS is the date the new source begins operation. Deadlines for compliance with BCT and BAT are established in NPDES permits.

In accordance with 40 CFR part 23, this regulation shall be considered issued for the purposes of judicial review at 1 p.m. Eastern time on March 18, 1993. Under section 509(b)(1) of the Clean Water Act, judicial review of this regulation can be had only by filing a petition for review in the United States Court of Appeals within 120 days after the regulation is considered issued for purposes of judicial review. Under section 509(b)(2) of the Clean Water Act, the requirements in this regulation may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of April 5, 1993.

ADDRESSES: For additional technical information contact Mr. Ronald P. Jordan, Office of Water, Engineering and Analysis Division (WH-552), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC, 20460, (202) 260-7115. For additional information on the economic or regulatory impact analyses contact Dr. Mahesh Podar at the above address or by calling (202) 260-5387.

The complete public record for this rulemaking, including EPA's responses to comments received during rulemaking, is available for review at EPA's Water Docket; 401 M Street, SW., Washington, DC, 20460. For access to Docket materials, call (202) 260-3027 between 9 a.m. and 3:30 p.m. for an appointment. The EPA public information regulation (40 CFR part 2) provides that a reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Ronald P. Jordan at (202) 260-7115.

SUPPLEMENTARY INFORMATION:

Overview

This preamble describes the legal authority, background, technical and economic basis, and other aspects of the final regulation. The abbreviations, acronyms, and other terms used in this rule are defined in appendix A to the preamble of this rule.

Organization of This Rule

I. Scope of This Rulemaking

This final regulation establishes effluent limitations guidelines and standards of performance for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category under sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act (The Federal Water Pollution Control Act Amendments of 1972; as amended by the Clean Water Act of 1977 and the Water Quality Act of 1987), 33 U.S.C. 1311, 1314 (b), (c), and (e), 1316, 1317, 1318 and 1361; 86 Stat. 816, Public Law 92–500; 91 Stat. 1567, Public Law 95–217; 101 Stat. 7, Public Law 100–4 ("the Act" or "CWA"). This regulation is also established in response to a Consent Decree entered on April 5, 1990 (subsequently modified on May 28, 1992) in *NRDC* v. *Reilly*, D. D.C. No. 79–3442 (JHP) and is consistent with EPA's Effluent Guidelines Plan under section 304(m) of the CWA (September 8, 1992, 57 FR 41000). This regulation is referred to as the offshore guidelines throughout this preamble.

This regulation applies to discharges from offshore oil and gas extraction facilities, including exploration, development and production operations, that are seaward of the inner boundary of the territorial seas. The inner boundary of the territorial seas is defined in section 502(8) of the CWA as "the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters" (hereafter referred to as "shore"). The processes and operations which comprise the offshore oil and gas extraction subcategory (Standard Industrial Classification (SIC) Major Group 13), are currently regulated under 40 CFR part 435, subpart A. The existing effluent limitations guidelines, which were issued on April 13, 1979 (44 FR 22069), are based on the achievement of best practicable control technology currently available (BPT).

In general, BPT represents the average of the best existing performances of well known technologies and techniques for control of pollutants. BPT for the offshore subcategory limits the discharge of oil and grease in produced water to a daily maximum of 72 mg/l and a thirty day average of 48 mg/l; prohibits the discharge of free oil in deck drainage, drilling fluids, drill cuttings, and well treatment fluids; and, for sanitary wastes, requires a minimum residual chlorine content of 1 mg/l and prohibits the discharge of floating solids. BPT limitations are not being changed by this rule.

This rule establishes regulations based on best available technology economically achievable (BAT) that will result in reasonable progress toward the goal of the CWA to eliminate the discharge of all pollutants. At a minimum, BAT represents the best economically achievable performance in the industrial category or subcategory. This rule also establishes requirements based on best conventional pollutant control technology (BCT) and establishes new source performance standards (NSPS) based on the best demonstrated control technology.

Under this rule, EPA is establishing BCT, BAT and NSPS limitations prohibiting the discharge of drilling fluids and drill cuttings from wells located within three miles from shore (the inner boundary of the territorial seas). For wells located more than three miles from shore, BAT and NSPS: (1) Limit toxicity at 30,000 ppm in the suspended particulate phase; (2) limit cadmium and mercury at 3 mg/kg and 1 mg/kg, respectively, in stock barite (on a dry weight basis); (3) prohibit the discharge of diesel oil; and (4) prohibit the discharge of free oil with compliance determined by the static sheen test. BCT is limited to the control of conventional pollutants, and in this rule prohibits discharges of free oil beyond three miles from shore. All wells drilled off the Alaskan coast are excluded from the zero discharge limitation; instead, all discharges of drilling fluids and drill cuttings off Alaska must comply with the limitations on toxicity, cadmium, mercury, free oil, and diesel oil regardless of distance from shore.

Under BAT and NSPS, the discharge of oil and grease in produced water will be limited to a maximum for any one day (referred to as daily maximum) of 42 mg/l and an average of daily values for 30 consecutive days (referred to as monthly average) of 29 mg/l based on improved operating performance of gas flotation technology. BCT for produced water is being established equal to the current BPT limitations on oil and grease.

Discharges of produced sand are prohibited under BCT, BAT and NSPS. BCT, BAT and NSPS limitations for deck drainage are being set equal to the current BPT limitations prohibiting discharges of free oil. Compliance with the no discharge of free oil limit for deck drainage is to be determined by the visual sheen test.

For treatment, completion and workover fluids, the rule establishes BAT and NSPS limiting the discharge of oil and grease at a daily maximum of 42 mg/l and a monthly average of 29 mg/l. BCT for well treatment, completion and workover fluids is being set equal to the BPT prohibition on discharges of free oil (compliance by static sheen).

EPA is promulgating limitations on domestic wastes which prohibit the discharge of foam (under BAT and NSPS) and floating solids (under BCT and NSPS), and incorporate U.S. Coast Guard regulations (under BCT and NSPS) prohibiting discharges of garbage as required at 33 CFR part 151. For sanitary wastes, EPA is promulgating BCT and NSPS limitations equal to BPT limitations on floating solids and residual chlorine. EPA is not establishing BAT for sanitary wastes because no toxic or nonconventional pollutants of concern have been identified in these wastes.

II. Legal Authority and Background

This regulation is promulgated under the authority of sections 301, 304 (b), (c), and (e), 306, 307, 308, and 501 of the CWA.

The CWA establishes a comprehensive program to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters" (CWA section 101(a)). To implement the Act, EPA is to issue technology-based effluent limitations guidelines, new source performance standards and pretreatment standards for industrial dischargers. The levels of control associated with these effluent limitations guidelines and the new source performance standards for direct dischargers are summarized briefly below. Since no offshore facilities currently discharge into publicly-owned treatment works (POTWs), pretreatment standards are not included in this rule and are reserved.

A Consent Decree that was entered on April 5, 1990 (*NRDC* v. *Reilly*, D.D.C. No. 79-3442), required EPA to propose or repropose BAT and BCT effluent limitations guidelines and new source performance standards for produced water, drilling fluids and drill cuttings, well treatment fluids, and produced sand by November 16, 1990. The 1990 Consent Decree required EPA to promulgate final guidelines and standards for these wastestreams by June 19, 1992. Also, EPA was required to determine by November 16, 1990 whether effluent limitations guidelines and new source performance standards covering deck drainage and domestic and sanitary wastes were appropriate. If EPA determined that deck drainage and domestic and sanitary wastes should be regulated, then final effluent guidelines and standards covering these waste streams were to be promulgated by June 30, 1993. On May 28, 1992, the Court modified the Consent Decree to extend the date for promulgation of final effluent guidelines and standards for produced water, drilling fluids and drill cuttings, well treatment fluids, and produced sand from June 19, 1992 to January 15, 1993. EPA has determined that rules for deck drainage, domestic wastes, and sanitary wastes are appropriate and is promulgating limits for these wastestreams in this rule.

A. Best Practicable Control Technology Currently Available (BPT)

BPT limitations are generally based on the average of the best existing performance by plants of various sizes, ages, and unit processes within the point source category or subcategory.

In establishing BPT limitations, EPA considers the total cost in relation to the age of equipment and facilities involved, the processes employed, process changes required, engineering aspects of the control technologies and non-water quality environmental impacts (including energy requirements). The total cost of applying the technology is considered in relation to the effluent reduction benefits.

B. Best Available Technology Economically Achievable (BAT)

BAT limitations, in general, represent the best existing performance in the industrial subcategory or category. The Act establishes BAT as a principal national means of controlling the direct discharge of toxic and nonconventional pollutants. In arriving at BAT, EPA considers the age of the equipment and facilities involved, the process employed, the engineering aspects of the control technologies, process changes, the costs and economic impact of achieving such effluent reduction, non-water quality environmental impacts, and such other factors as the Administrator of EPA deems appropriate. EPA retains considerable discretion in assigning the weight to be accorded these factors.

C. Best Conventional Pollutant Control Technology (BCT)

The 1977 Amendments added section 301(b)(2)(E) to the Act establishing "best conventional pollutant control technology" (BCT) for discharges of conventional pollutants from existing industrial point sources. Section 304(a)(4) of the Act designated the following as conventional pollutants: biochemical oxygen demand (BOD), 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).

BCT is not an additional limitation, but replaces BAT for the control of conventional pollutants. In addition to other factors specified in section 304(b)(4)(B), the Act requires that BCT limitations be established in light of a two part "cost-reasonableness" test. *American Paper Institute* v. *EPA*, 660 F.2d 954 (4th Cir. 1981). EPA first published its methodology for carrying out the BCT analysis on August 19, 1979 (44 FR 50372).

A revised methodology for the general development of BCT limitations was proposed on October 29, 1982 (47 FR 49176), and became effective on August 22, 1986 (51 FR 24974; July 9, 1986).

D. New Source Performance Standards (NSPS)

NSPS are based on the best available demonstrated technology. New plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. Therefore, Congress directed EPA 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 addition, in establishing NSPS, EPA is required to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

III. Overview of the Industry

A. Exploration, Development, and Production

Exploration and development activities for the extraction of oil and gas include work necessary to locate and drill wells. Exploration activities are those operations involving the drilling of wells to determine the potential hydrocarbon reserves. Exploratory activities are usually of short duration at a given site, involve a small number of wells, and are generally conducted from mobile drilling units. Development activities involve the drilling of production wells once a hydrocarbon reserve has been discovered and delineated. These operations, in contrast to exploration activities, usually involve a large number of wells which may be drilled from either fixed or floating platforms or mobile drilling units. Production operations include all work necessary to bring hydrocarbon reserves from the producing formation and begin with the completion of each well at the end of the development phase.

B. New and Existing Sources

1. New Source Definition

The Offshore Guidelines apply to all mobile and fixed drilling (exploratory and development) and production operations. Because many oil and gas facilities are mobile (particularly exploratory and development rigs), rather than stationary facilities that are typically covered by new source performance standards (NSPS), EPA's 1985 proposal discussed at length the question of which of these facilities should be considered new sources and which should be considered existing sources under these Guidelines. 50 FR 34617-34619 (Aug. 26, 1985).

As discussed in that proposal, provisions in the NPDES regulations define "new source" (40 CFR 122.2) and establish criteria for a new source determination. (40 CFR 122.29(b)). In the 1985 proposed Offshore Guidelines, (50 FR 34592, 34617-19, Aug. 26, 1985), EPA proposed special definitions applicable to new sources in the offshore subcategory which are consistent with 40 CFR 122.29 and which provide that 40 CFR 122.2 and 122.29(b) shall apply "Except as otherwise provided in an applicable new source performance standard." See 49 FR 38046 (Sept. 26, 1984).

Section 306(a)(2) of the CWA defines "new source" to mean "any source, the construction of which is commenced after publication of the proposed NSPS if such standards are promulgated consistent with section 306." The Act defines "source" to mean any "facility * * * from which there is or may be a discharge of pollutants" and "construction" to mean "any placement, assembly, or installation of facilities or equipment * * * at the premises where such equipment will be used."

The regulations at 40 CFR 122.2 implementing this provision state in part:

"*New Source* means any building, structure, facility, or installation from which there is or may be a 'discharge of pollutants,' the construction of which is commenced:

(a) After promulgation of standards of performance under section 306 of CWA which are applicable to such source, or

(b) After proposal of standards of performance in accordance with section 306 of CWA which are applicable to such source, but only if the standards are promulgated in accordance with section 306 within 120 days of their proposal."

The regulations at 40 CFR 122.29(b)(4) state:

"(4) Construction of a new source as defined under 40 CFR 122.2 has commenced if the owner or operator has:

(i) Begun, or caused to begin as part of a continuous on-site construction program:

(A) Any placement assembly, or installation of facilities or equipment; or

(B) *Significant site preparation work* including clearing, excavation or removal of existing buildings, structures or facilities which is necessary for the placement, assembly, or installation of new source facilities or equipment; or

(ii) Entered into a binding contractual obligation for the purchase of facilities or equipment which are intended to be used in its operation with a reasonable time. Options to purchase or contracts which can be terminated or modified without substantial loss, and contracts for feasibility engineering, and design studies do not constitute a contractual obligation under the paragraph." (emphasis added).

EPA has developed an interpretation of "new source" that will apply to the offshore subcategory that the Agency believes is reasonable and effectuates the intent of the CWA and EPA's regulations defining new sources generally. In the final rule, EPA intends to follow the approach first proposed in 1985, in which EPA proposed to define, for purposes of the Offshore Guidelines, "significant site preparation work" as "the process of clearing and preparing an area of the ocean floor *for purposes of constructing or placing a development or production facility on or over the site.*" (emphasis added). Thus, development and production facilities at a new site would be new sources under the Offshore Guidelines. Further, with regard to 40 CFR 122.29(b)(4)(ii), EPA stated that although it was not "proposing a special definition of this provision believing it should appropriately be a decision for the permit writer," EPA suggested that the definition of new source include development or production facilities even if the discharger entered into a contract for purchase of facilities or equipment prior to publication, if no specific site was specified in the contract. Conversely, EPA suggested that the definition of new source exclude development or production facilities if the discharger entered into a contract prior to publication and a specific site was specified in the contract. In the final rule, EPA also intends to follow this approach.

As a consequence of the proposed definition of "significant site preparation work," if "clearing or preparation of an area for development or production has occurred at a site prior to the publication of the NSPS, then subsequent development and production activities at that site would not be considered a new source." (See 50 FR 34618) Also, exploration activities at a site would not be considered significant site preparation work; therefore, exploratory wells would not be new sources in any circumstance. (50 FR 34618) Exploration operations are short term, typically lasting only three to six months (as weather and climate and drilling conditions allow), while development and production operations occur over a much longer timeframe. The Agency does not consider exploratory activities to be "significant site preparation work" because such activities are not necessarily followed by development or production activity at a site. Even when exploratory drilling leads to development and production activities, the latter may not be commenced for months or years after the exploratory drilling is completed. The purpose of distinguishing between exploratory drilling and significant site preparation for production and development operations is to "grandfather" as an existing source any source if "significant site preparation work," * * * "evidencing an intent to establish full scale [development or production] operations at a site, had been performed prior to NSPS becoming effective." (50 FR 34618) At the same time, if only exploratory drilling had occurred prior to NSPS becoming effective, then subsequent drilling and production activities would make the facility a new source.

EPA also proposed a special definition for "site" in the phrase "significant site preparation work" used in 40 CFR 122.2 and 40 CFR 122.29(b). "Site" is defined in 40 CFR 122.2 as "the land or water area where any 'facility or activity' is physically located or conducted, including adjacent land used in connection with the facility or activity." EPA proposed that the term "water area" mean the "specific geographical location where the exploration, development, or production activity is conducted, including the water column and ocean floor beneath such activities. Therefore, if a new platform is built at or moved from a different location, it will be considered a new source when placed at the new site where its oil and gas activities take place. Even if the platform is placed adjacent to an existing platform, the new platform will still be considered a 'new source,' occupying a new 'water area' and therefore a new site." [50 FR 34618 (Aug. 26, 1985)].

As a consequence of these distinctions, exploratory facilities would always be existing sources. Production and development facilities where significant site preparation has occurred prior to the effective date of the Offshore Guidelines would also be existing sources. These same production and development facilities, however, would become "new sources" under the proposed regulatory definition if they moved to a new water area to commence production or development activities. The proposed definition, however, presents a problem because even though these facilities would be "new sources" subject to NSPS, they could not be covered by an NPDES permit in the period immediately following the issuance of these regulations. This is because no existing permits could have included NSPS until NSPS were promulgated.

To resolve this problem, the final rule temporarily excludes from the definition of "new source" (pending EPA's issuance of appropriate permits covering these facilities) new development and production facilities that would otherwise be "new sources" if, as of the effective date of the Offshore Guidelines, the facilities are subject to an existing NPDES permit. EPA believes this approach is reasonable because when Congress enacted section 306 of the CWA it did not specifically address mobile activities of the sort common in this industry, as distinguished from activities at stationary facilities on land that had not yet been constructed prior to the effective date of applicable NSPS. Moreover, EPA believes that Congress did not intend that the promulgation of NSPS would result in stopping all oil and gas activities which would have been authorized under existing NPDES permits as soon as the NSPS are promulgated.

While the situation of mobile oil and gas facilities is rather unique, EPA faced a similar issue in its effluent limitations guidelines for the placer mining industry. Placer mines are also mobile, generally moving downstream or upstream. In that effluent guideline, 40 CFR 440.144(c), EPA set forth a number of factors that the Regional Administrator or Director of a state program with authority to administer the NPDES program should take into account in making a case-by-case determination of whether a placer mine constitutes a "new source." Three of these factors relate to whether the mine would operate in an area which is covered by a valid NPDES permit. (Another factor was whether the mine significantly alters the quantity or nature of pollutants discharged.) The United States Court of Appeals for the Ninth Circuit upheld this approach. "We find that the criteria set forth on what is a new-source placer mine are within the ambit of authority which Congress gave the EPA in the Clean Water Act and cannot be considered arbitrary or capricious." *Rybachek* v. *U.S. E.P.A.*, 904 F.2d 1276, 1293 (9th Cir. 1990).

Now that NSPS are promulgated, EPA will apply NSPS to appropriate facilities (i.e., those where there is significant site preparation work for development or production after promulgation of NSPS) within the Offshore Subcategory. EPA notes that BAT limitations are equal to NSPS in this rule. EPA intends to issue new source NPDES permits covering production and development facilities as soon as possible.

2. Industry Profile

Existing Platforms (BAT/BCT): EPA's industry profile estimates include structures that would incur costs under this rule. The estimate of existing structures includes only those platforms (1) in production, (2) with specific products (i.e., oil, gas, or both), (3) with a specific number of wells drilled or in production, (4) discharging, and (5) in the offshore subcategory. Two major sources of data were used to develop a profile of offshore oil and gas activities in the Gulf of Mexico (GOM). In the March 1991 proposal, EPA used the "Minerals Management Service (MMS) Platform Inspection System, Complex/Structure Data Base" to estimate the number of structures in the federal waters of the Gulf of Mexico that are likely to bear compliance costs under this rule. This estimate of 2,233 existing structures in the Gulf of Mexico (GOM) federal waters remains unchanged. A limitation of the March 1991 profile was that it lacked sufficient data regarding activities in state waters of the GOM. To fill this data gap and in response to comments received, EPA conducted a mapping effort to identify structures in production in state waters. Using maps and electronic data, EPA (1) identified wells whose well-head location lay seaward of the baseline that separates the coastal and offshore subcategories; (2) identified wells belonging to common platforms; and (3) verified which wells were still in production. As a result of this effort to update the industry profile, an additional 284 structures were identified in GOM state waters. For the Pacific, 32 structures are included in the BAT/BCT count of existing structures. There are no structures in the Atlantic at this time. Structures off Alaska in Cook Inlet are in the coastal subcategory and are not affected by this rulemaking. Currently, there is only one existing facility in Alaskan waters that is seaward of the inner boundary of the territorial seas. This facility is already required by State requirements to reinject produced water and incremental compliance costs associated with this rule are minimal. No existing Alaskan structures are projected to incur significant incremental compliance costs under this rule. A total of 2,549 offshore structures is used in the BAT/BCT economic impact analysis.

Future Drilling Projections (BAT/BCT and NSPS): Offshore drilling efforts vary from year to year depending on such factors as the price and supply of oil, the amount of state and federal leasing, and reservoir discoveries. EPA estimates future drilling activity averaging 759 wells per year during the 15-year period, from 1993–2007, after promulgation of this regulation. Estimated activity in the Gulf of Mexico and Alaska are based on MMS 30-year regionalized forecasts with an average barrel of oil equivalent (BOE) price of $21/bbl (1986 dollars) for the 15-year period. The drilling projections presented in the 1991 proposal for the Gulf of Mexico and Alaska were based on a 1986–2000 time frame. Moving the starting year forward for the 15-year period, from 1986 to 1993, resulted in about a three percent change in the number of wells from the original set of projections (i.e., slightly higher if based on the year 1990, slightly lower for projections beginning in 1993). Because the projection of estimated future activity does not change significantly by starting in 1992 rather than in 1986, EPA is using its projections beginning in 1986. Recent Presidential moratoria have prevented offshore activities in certain areas in the Eastern Gulf of Mexico, but this is not expected to cause a significant change in the regional estimate of future activity.

Recent moratoria and restricted leasing in the Pacific constrain drilling estimates to the level of activity associated with drilling on installed structures and existing leases. Due to the Presidential decision to cancel lease sale 96 (Georges Bank region in the North Atlantic) and strictly limit any activity in this planning area until after the year 2000, no activity is projected for the Atlantic during the 1986–2000 time period. (EPA is aware of one site off the coast of North Carolina where an operator has expressed interest in drilling.) EPA anticipates that these restrictions will remain applicable until after the year 2007. This set of projections corresponds to the "restricted" or "constrained" well forecast presented in the March 1991 proposal.

The projection of 759 wells drilled per year includes all new well—productive, non-productive (dry holes), exploratory, and development. The new well projections therefore include both BAT and NSPS wells. As explained above, BAT wells encompass exploratory wells in addition to development and production wells for which significant site preparation takes place prior to promulgation of the regulation. NSPS wells are drilled on platforms where significant site preparation and installation take place after promulgation of the regulation. Table 1 is a summary of the BAT and NSPS wells by region. Approximately one-third of the new wells may be considered existing sources. (The actual percentage of wells classified as existing sources will vary in time. Most will be exploratory efforts. The number of new wells drilled on existing platforms will decrease in time as those platforms complete their drilling programs. The numbers given in Table 1 reflect the annual average number of wells during the 15-year period following promulgation of the regulation.)

TABLE 1.—AVERAGE ANNUAL NEW WELL DRILLING
[wells/year]

Region	Existing sources (BAT)	New sources (NSPS)	Total
Gulf	215	500	715
Pacific	32	0	32
Alaska	3	9	12
Total	250	509	759

New Platforms: Platform projections were made based on the number of productive wells. An estimated total of 759 platforms will be installed during the 15-year period after promulgation of the regulation. The fact that the estimated average annual number of wells (759) is the same as the total number of platforms (759) installed during the 15-year period is coincidental.

C. Waste Streams

The primary wastewater sources from the exploration and development phases of the offshore oil and gas extraction industry include the following:

- Drilling fluids.
- Drill cuttings.
- Sanitary wastes.
- Deck drainage.
- Domestic wastes.

The primary wastewater sources from the production phase of the industry include the following:

- Produced water.
- Produced sand.
- Sanitary wastes.
- Deck drainage.
- Domestic wastes.
- Well treatment, completion and workover fluids.

Drilling fluids (typically termed muds) and drill cuttings are the most significant waste streams from exploratory and development operations in terms both of volume and toxic pollutants. Produced water is the largest waste stream from production activities based on its volume of discharge and quantity of pollutants. Deck drainage, sanitary wastes, domestic wastes, produced sand, and well treatment, completion, and workover fluids are often classified under the term miscellaneous wastes.

Drilling fluids are any fluid sent down the drillhole to aid the drilling process. This includes those materials used to maintain hydrostatic pressure control in the well, lubricate the drill bit, remove drill cuttings from the well, and stabilize the walls of the well during drilling or workover operations. A water-based drilling fluid is the conventional drilling system in which water is the continuous phase. Drill cuttings are the solids generated by drilling into subsurface geologic formations and are carried to the surface by the drilling fluid system.

Produced water is brought up from the hydrocarbon-bearing strata along with produced oil and gas. This waste stream can include formation water, injection water, and any chemicals (including well treatment, completion or workover fluids) added downhole or during the oil/water separation process.

Deck drainage includes all wastewater resulting from platform washings, deck washings, rainwater, and runoff from curbs, gutters, and drains including drip pans and work areas.

Well treatment fluids are fluids that resurface from acidizing and/or hydraulic fracturing operations to improve hydrocarbon recovery. Workover fluids and completion fluids are low solids fluids used to prepare a well for production, provide hydrostatic control, and/or prevent formation damage.

Produced sand consists of the slurried particles which surface from hydraulic fracturing and the accumulated formation sands and other particles (including scale) generated during production. This waste stream also includes sludges generated in the produced water treatment system, such as tank bottoms from oil/water separators and solids removed in filtration.

Sanitary wastes originate from toilets. Domestic wastes originate from sinks, showers, laundries, and galleys.

EPA presented detailed discussions of the origins and characteristics of the wastewater effluents from exploration, development, and production in the March 13, 1991 proposal. EPA generally focused data gathering efforts and data analyses on drilling fluids, drill cuttings, and produced water due to their volumes and potential toxicity. Information on the miscellaneous wastes is more limited. Their volumes are generally smaller, and in most cases are either infrequently discharged or are commingled with the major waste streams. However, EPA has determined that it is appropriate to promulgate regulations for miscellaneous wastes as well.

IV. Development of the Final Regulation

On September 15, 1975, EPA promulgated interim final BPT effluent limitations guidelines (40 FR 42543) and proposed BAT and NSPS regulations (40 FR 42572) for the offshore subcategory of the oil and gas extraction point source category ("offshore subcategory"). EPA promulgated final BPT regulations on April 13, 1979 (44 FR 22069), but deferred action on the BAT and NSPS regulations. Table 2 presents the 1979 BPT limitations.

The Natural Resources Defense Council (NRDC) filed suit on December 29, 1979 seeking an order to compel the Administrator to promulgate final NSPS for the offshore subcategory. In settlement of the action (*NRDC* v. *Costle*, C.A. No. 79–3442 (D. D.C.)(JHP)), EPA acknowledged the statutory requirement and agreed to take steps to issue such standards. However, because of the length of time that had passed since proposal, EPA believed that examination of additional data and reproposal were necessary. Consequently, EPA withdrew the proposed NSPS on August 22, 1980 (45 FR 56115). The proposed BAT regulations were withdrawn on March 19, 1981 (46 FR 17567).

On August 26, 1985 (50 FR 34592) EPA proposed BAT and BCT effluent limitations guidelines and new source performance standards for the offshore subcategory. The 1985 proposal also included an amendment to the BPT definition of "no discharge of free oil." The waste streams covered by the 1985 proposal were drilling fluids, drill cuttings, produced water, deck drainage, well treatment fluids, produced sand, and sanitary and domestic wastes.

TABLE 2.—BPT EFFLUENT LIMITATIONS (PROMULGATED 1979)

Waste stream	Parameter	BPT effluent limitation
Produced water	Oil and grease	72 mg/l daily maximum.
		48 mg/l 30-day average.
Drilling fluids	Free oil	No discharge.
Drill cuttings	Free oil	No discharge.
Well treatment fluids.	Free oil	No discharge.
Deck drainage	Free oil	No discharge.
Sanitary-M10	Residual chlorine.	1 mg/L (minimum.)
Sanitary-M9IM	Floating solids	No discharge.

On October 21, 1988, EPA issued a Notice of Data Availability (53 FR 41356) concerning the development of NSPS, BAT, and BCT regulations for the drilling fluids and drill cuttings waste streams (the "1988 notice"). The 1988 notice presented substantial additional and revised technical, cost, economic, and environmental effects information which EPA collected after publication of the 1985 proposal. EPA presented new information regarding the diesel oil prohibition and the toxicity limitation, and new compliance costing and economic analysis results based on new profile data and treatment and control option development. The new control technologies discussed were based on thermal distillation, thermal oxidation, and solvent extraction. Performance data for these technologies were also included. In addition, EPA proposed requirements for limitations on metals content in the stock barite based on the use of existing barite supplies, or alternatively in the drilling fluids (whole fluid basis) at the point of discharge.

On January 9, 1989, EPA published a Correction to Notice of Data Availability (54 FR 634) concerning the analytical method for the measurement of oil content and diesel oil. The 1988 notice had inadvertently published an incomplete version of that method.

On November 26, 1990, EPA published a notice and a reproposal (55 FR 49094) that presented the major BCT, BAT, and NSPS regulatory options under consideration for control of drilling fluids, drill cuttings, produced water, deck drainage, produced sand, domestic and sanitary wastes, and well treatment, completion, and workover fluids. On March 13, 1991 (56 FR 10664), EPA published a second notice proposing BAT, BCT, and NSPS limitations and standards for the offshore subcategory. The regulatory options presented were the same as those proposed on November 26, 1990 with the exception of deleting a requirement under NSPS which prohibited the discharge of visible foam from the sanitary wastestream (the requirement had been inadvertently included in the November 1990 proposal).

The 1990 and 1991 proposals did not supersede the 1985 proposal entirely. Rather, they revised the 1985 proposal in certain areas. The revisions were based on new data and information acquired by EPA since the 1985 proposal regarding waste characterization, treatment technologies, industrial practices, industry profiles, analytical methods, environmental effects, costs, and economic impacts. Some of this new information regarding drilling wastes had been published in a Notice of Data Availability (53 FR 41356) (October 21, 1988). This new information led EPA to develop additional regulatory options to those proposed in 1985.

On April 5, 1991 (56 FR 14049) EPA published notification of public workshops for the guidelines proposed on March 13, 1991, and extended the comment period for the proposed rule. The comment period for the majority of the rule was extended by 30 days. The comment period for membrane filtration and radioactivity issues was extended by 60 days, and ended on June 11, 1991.

The Consent Decree was again revised on May 28, 1992. Under this modification, the date for promulgation of the final effluent limitations guidelines and standards (BCT, BAT, and NSPS) for produced water, drilling fluids and drill cuttings, well treatment fluids, and produced sand wastestreams was extended from June 19, 1992 to January 15, 1993.

Ocean discharge criteria applicable to this industry subcategory were promulgated on October 3, 1980 (45 FR 65942) under section 403(c) of the Act. These guidelines are to be used in making site-specific assessments of the impacts of discharges. Section 403 limitations are imposed through section 402 National Pollutant Discharge Elimination System (NPDES) permits. Section 403 is intended to prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal.

In addition, EPA has issued a series of general NPDES permits that set BAT and BCT limitations applicable to sources in the offshore subcategory on a Best Professional Judgment (BPJ) basis under section 402(a)(1) of the Clean Water Act. See e.g., 57 FR 54642 (November 19, 1992) (Western Gulf of Mexico OCS General Permit); 51 FR 24897 (July 9, 1986), (Gulf of Mexico OCS General Permit); 49 FR 23734 (June 7, 1984), modified 52 FR 30481 (September 29, 1987) (Bering and Beaufort Seas General Permit); 50 FR 23570 (June 4, 1985) (Norton Sound General Permit); 51 FR 35400 (October 3, 1986) (Cook Inlet/Gulf of Alaska General Permit); 53 FR 37840 (September 20, 1988), modified 54 FR 39574 (September 27, 1989) (Beaufort Sea II/Chukchi Sea General Permits). The rulemaking record for this final rule includes copies of the most significant **Federal Register** notices proposing these general permits and issuing them in final form.

The Gulf of Mexico General Permit was challenged by industry and an environmental group. *Natural Resources Defense Council* v. *EPA*, 863 F.2d 1420 (9th Cir. 1988). The Bering and Beaufort Sea General Permits were the subject of industry challenge. *American Petroleum Institute* v. *EPA*, 965 F.2d (5th Cir. 1986); later opinion following partial remand, 858 F.2d 261, (5th Cir. 1988); clarified and rehearing denied, 864 F.2d 1156 (5th Cir. 1989). Copies of these decisions are also included in the rulemaking record.

V. Major Changes to the Data Base for the Final Regulation

This section describes several of the most significant changes to the methodology and data base which have occurred since the proposals. Other areas of change and issues are discussed in other sections of this preamble, the Development Document, the Economic Impact Analysis, the Regulatory Impact Analysis, and the record for this rule.

A. Drilling Fluids and Drill Cuttings

1. Engineering Costs

a. *BAT and NSPS Costing Methodology.* The costing methodology for the final rule is based on the costing methodology presented in the March 13, 1991 proposal. However, EPA improved the database and sought additional confirmatory data in response to comments on the proposal. As discussed in the March 1991 proposal, EPA created a database and computer models to generate regionalized costing estimates for the handling and ultimate disposal of spent drilling fluids and drill cuttings. The database consists of the following elements:

- Projections of the number of wells that will be drilled over the next 15-year period in each geographic region.
- Characteristics of a "model well" describing average values for parameters such as well depth, volume of waste associated with drilling activity, use of additives to aid in drilling, and length of time to drill a well.
- Characteristics of drilling wastes, specifying pollutant concentration and physical properties of the waste specific to certain drilling scenarios.
- Failure rates of drilling wastes with respect to compliance tests for certain discharge limitations (e.g., static sheen, toxicity).
- Compliance costs, including analytical costs and disposal costs for transportation and land disposal of drilling wastes.

The data were entered into the computer models designed to predict regionalized compliance costs and pollutant removals for the various regulatory options considered. An analysis of each option was conducted to determine:

- Number of wells affected
- Cost incurred by industry to comply with the regulation
- Volume and percent of drilling waste requiring onshore disposal
- Direct and incidental pollutant removal

No distinction was made between the BAT and NSPS wells for compliance costing because of the negligible differential in drilling fluids and drill cuttings compliance costs between a new well drilled as an existing source and one drilled as a new source. For BAT and NSPS, the computer models identified costs and pollutant removals which were incremental beyond what was required for "current" levels of control. Current control levels reflected existing NPDES permit requirements that EPA considered representative of control measures in practice. The current requirements were (and are) often more stringent than BPT.

b. *Costing Assumptions*. In projecting compliance costs, EPA made several assumptions about the current drilling practices to characterize the industry. These assumptions were based on Agency-sponsored analyses, industry-sponsored analyses, and public comments from previously published proposals or notices of data availability. Several assumptions presented in the rulemaking record as part of the March 13, 1991 proposal have been updated due to further investigation by EPA or through submission of additional data in public comments. EPA's reevaluation of costing assumptions has led to a reduction in barite usage volumes, barite substitution costs, onshore disposal volumes, and onshore disposal costs. The following paragraphs discuss the manner in which assumptions presented in previous costing estimates have been revised for the final rule.

The estimated volume of drilling fluids and drill cuttings generated have changed slightly due to revisions in calculations of: the average well depth, the deep well depth, and the percentage of wells greater than the average well depth. The determination of the volumes of drilling fluids and drill cuttings generated is still based on data and the methodology presented by the Offshore Operators Committee report entitled "Alternate Disposal Methods for Muds and Cuttings: Gulf of Mexico and Georges Bank," December 7, 1981. EPA revised the average model well depths, the deep well depths, and the percentage of wells greater than the average well depth to include well depth data from the API Joint Association Survey on Drilling Costs for a period of five years. The well depth data used for the March 1991 proposal was based on one year of data. The revised average well depths for the model wells are as follows: 10,559 feet in the Gulf of Mexico, 7,607 feet offshore California, and 10,633 feet offshore Alaska.

Since deep wells (those greater than 10,000 feet in depth) require larger bore holes and thus generate greater waste volumes, it is important to consider the frequency of drilling deep wells. Industry drilling data were used to revise estimates of the typical deep well depths as follows: 13,037 feet in the Gulf of Mexico, 10,081 feet offshore California, and 12,354 feet offshore Alaska. The proportion of wells drilled deeper than 10,000 feet was also revised. At proposal, EPA assumed that 30.8% of all wells would be deeper than 10,000 feet and that percentage was used for all regions. Based on data evaluated for this final rule, EPA revised estimates of the proportion of deep wells as follows: 49 percent in the Gulf of Mexico, 42 percent off California, and 59 percent off Alaska. At proposal, EPA used the waste volumes generated by model wells to estimate onshore disposal requirements. In reassessing these estimates, EPA made a distinction between the waste volumes generated from model wells and deep wells to more accurately characterize pollutant removals and onshore disposal requirements.

In the March 1991 proposal, EPA assumed that all deep wells used a mineral oil-based drilling fluid for that footage drilled deeper than 10,000 feet. Several industry commenters and a trade association stated that fifteen percent (15%) is a more representative estimation of the oil-based mud usage for deep well projects, and provided EPA with recent data on usage of oil-based drilling fluids. Upon review of this data, EPA revised its computer model to assume fifteen percent of all wells drilled deeper than 10,000 feet would utilize an oil-based drilling fluid. The application of this assumption projects a lower volume of drilling waste requiring onshore disposal. The previous estimates assumed that all drilling wastes generated deeper than 10,000 feet would require onshore proposal due to noncompliance with the free oil and toxicity limitations. However, the decrease in onshore disposal volumes based on new information is offset by the new information about greater numbers of deep wells and greater volumes from deep wells due to larger bore hole diameters.

Since proposal, EPA also revised its assumptions about the characteristics of the type of drilling fluids (or "muds") used, e.g., density of drilling fluids. In evaluating comments which disputed pollutant removal estimates for drilling wastes, EPA revised its assumptions about the mud compositions. The methodology used in the proposal attempted to characterize the drilling fluids used in different portions of the well based on drilling depth, lubricity, and type of mud (water-based or oil-based). In the March 1991 proposal, EPA made assumptions regarding barite use which were equivalent to the barite concentration in a relatively high density (18 pound per gallon) drilling fluid. Since proposal, EPA has learned that such high density drilling fluids are generally used only at deep well depths or for unusual circumstances, and they are not considered representative of the mud systems typically used in offshore drilling projects. Also, EPA's reevaluation of the metals loadings derived from the previous mud compositions revealed incomplete mass balances with the barite volumes in the muds and the barium concentrations in the metals database. (In other words, the amount of barite in drilling fluids did not correspond to the measured barium concentrations in the discharge of drilling fluids and drill cuttings.) To alleviate these inconsistencies, to simplify the costing model, and to characterize more accurately the drilling fluids used by the industry, EPA revised the estimated mud compositions to that of a drilling fluid with an average density of 11 pounds per gallon (ppg) based on a review of discharge monitoring report data and communications with industry sources. EPA considers the 11 ppg mud to be representative of a typical drilling program that includes low density muds used for the initial stages of drilling, and the medium to heavy density muds used towards completion at the bottom of the well. The net result of this revised assumption is a reduction in estimates of barite usage, barite substitution costs, and pollutant removals for the drilling fluids and drill cuttings.

In concert with revising the drilling fluid composition, EPA revised the data characterizing the metals content in barite to more closely represent the composition of a typical drilling fluid. Barite is used as a weighting agent to assist in controlling downhole pressure. EPA derived updated metals concentrations in drilling fluids from a statistical analysis of the API/USEPA Metals Database. This database, from several sampling programs conducted by EPA and the industry, contains end-of-pipe metals concentrations in drilling fluids. EPA presented these data in the rulemaking record for the March 13, 1991 proposal. The metals data set includes additional elements that EPA determined to be of significant occurrence, concentration and toxicity. In addition to the priority pollutants presented in 56 FR 10699, EPA estimated removals for aluminum, iron, tin, and titanium.

The revised costing estimates also include updated regionalized onshore disposal costs. The onshore disposal costs presented in the March 1991 proposal consisted of one set of disposal costs for all geographical regions. In the reevaluation of the costing assumptions, EPA distinguished between costs for various geographic regions, namely the Gulf of Mexico, California, and Alaska.

Additional requirements placed on OCS sources under the recently promulgated air regulations for OCS sources (57 FR 40792; September 4, 1992) were considered in developing compliance costs for this rule. Emissions offset costs were calculated for all wells drilled off California, since this OCS planning area is adjacent to an onshore nonattainment area. Offset costs are assumed to be an annual expense and are included in the annual costs for the drilling fluids and drill cuttings options. Offset costs were calculated for nitrogen oxide and hydrocarbon emissions were calculated for this regulation based on annual costs of $15,000 per ton of nitrogen dioxide and $5,000 per ton of hydrocarbons.

2. Drilling Waste Pollutant Loadings

In projecting pollutant reductions resulting from this rule, EPA used an expanded data set some of which, although included in the rulemaking record at proposal, had been received too late to be included in the pollutant loadings analysis related to the metals content in drilling fluids. The updated metals concentrations were derived from a statistical analysis of the API/USEPA Metals Database. These data were obtained from several sampling programs sponsored by EPA and industry and represent end-of-pipe metals concentrations of drilling fluids. In addition to the priority pollutants used in loadings for the proposal, the pollutant loadings used for the final rule include aluminum, iron, tin, and titanium.

EPA also updated the pollutant loading estimates for drill cuttings. In the proposal, EPA based its loadings on estimates of barite concentration in the drill cuttings. In evaluating loadings for the final rule, EPA determined that previous estimates of 88 pounds of barite per barrel of drill cuttings were overestimates. The revised pollutant loading estimates for drill cuttings in this rule are based on the pollutants present in the drilling fluid adhering to the cuttings. Five percent, by volume, of drilling fluid adheres to drill cuttings after separation.

EPA's revision of the assumptions on drilling fluid composition also reduced estimates of the total suspended solid (TSS) content of the drilling fluids. The TSS concentration of the average drilling fluid density (11 ppg) serving as the basis for the projections for this rule is less than that of the higher density drilling fluid previously modeled in the 1991 proposal.

B. Produced Water

1. Gas Flotation Performance

EPA received additional data on performance of gas flotation technology in response to the 1991 proposal. The improved gas flotation technology basis for the produced water limitations considered for this final rule includes upstream gravity separation and chemical addition. This section summarizes these additional data and EPA's analysis, and presents limitations based on EPA's analysis.

Data available for this analysis included those collected for the EPA's 30 Platform Study (1981), the Offshore Operators Committee's (OOC) 42 Platform Study (1990), the OOC's 83 Platform Composite Study (1991), and EPA's "Oil Content in Produced Brine on Ten Louisiana Production Platforms" (1981).

For the EPA's 30 Platform Study, OOC member platforms were selected based on characteristics such as wide geographical distribution, type of production, ownership of the facility, and other non-random considerations. Seven of these thirty platforms used gravity separation and chemical addition followed by gas flotation to treat their produced water. All oil and grease measurements were made using EPA Method 413.1, a process for measuring total oil and grease. Grab samples of influent and effluent were measured.

For the OOC's 42 Platform Study, OOC member platforms were selected. The study was statistically designed to estimate within-process variation and laboratory variation. However, the sampling procedures used in the study inflate the estimated laboratory variation with some sampling variation. Total oil and grease measurements were made using Method 413.1. Grab samples of effluent were taken according to a balanced statistical design.

For the OOC's 83 Platform Composite Study, data from four studies were combined. These four studies include EPA's 30 Platform Study, OOC's 42 Platform Study, OOC's 10 Platform Database, and OOC's 12 Platform Refrigeration Study. The two additional OOC studies were designed in a fashion similar to that used for OOC's 42 Platform Study. All of the platforms in the OOC studies are described as conforming to specifications, operating properly, and adding chemicals as needed. All oil and grease measurements considered here were performed using Method 413.1 on grab samples of effluent. Again, the sampling procedures used inflate the laboratory variation estimate with some sampling variation.

For the EPA's "Oil Content in Produced Brine on Ten Louisiana Production Platforms," platforms were selected based on size, technology differences, and availability of living and working space. Grab samples of influent and effluent were measured for oil and grease by early methods for total oil and grease, insoluble oil and grease, and soluble oil and grease. Detailed information regarding the treatment system is summarized in the study report. Samples were taken according to a balanced statistical design.

All available oil and grease data for improved gas flotation, as measured by Method 413.1 were considered in establishing the limitations in the final rule. After screening platforms for compliance with current BPT limitations, EPA applied statistical methods to the data in order to calculate the long-term average concentration of oil and grease for use as the basis of the limitations. Then EPA calculated percentiles which express the relationship between the long-term average performance and the variability to be expected at a well-designed, operated, and maintained platform. The daily maximum limitation is set such that there is a 99 percent probability that a physical composite sample taken from the median performing platform will have total oil and grease measurements less than or equal to that concentration. Each physical composite is composed of four grab samples taken during a single day. The monthly average limitation is set such that there is a 95 percent probability that a monthly average of physical composite samples taken from the median performing platform will have total oil and grease measurements less than or equal to that concentration. The monthly average is the arithmetic average of four physical composite sample results collected during the same month (during a 30 day consecutive period). These percentiles correspond to large effluent values that would rarely be exceeded by a well-operated treatment system and represents levels that are achievable at all times under normal operating conditions.

The daily maximum limitation for total oil and grease not to be exceeded is a concentration of 42 mg/l and the monthly average limitation not to be exceeded is a concentration of 29 mg/l. Note that the addition of new data and the modification of the methodology for approximating percentiles for composite samples measurements based on grab sample measurements, each done in response to comments, has not greatly changed the Agency's estimate of what limitations would be appropriate based on this technology. In the 1991 proposal, EPA presented a daily maximum limitation of 38 mg/l and monthly average limitation of 27 mg/l based on this technology.

2. Produced Water Engineering Costs

The costing methodology for produced water in the final rule is the same as the methodology for produced water presented in the March 13, 1991 proposal. However, EPA made several changes to the database due to comments on the proposal and after EPA conducted further analysis of the industry. As discussed in the proposal, EPA created a database and developed computer models to generate regionalized costing estimates for the treatment and disposal of produced water. The database consisted of the following elements:

- Industry profile data on the number and type of platforms and produced water discharge rates.
- Projected future production activity.
- Produced water contaminant effluent levels associated with BPT treatment and with BAT and NSPS treatment options.
- Cost to implement the BAT and NSPS treatment technology options.

Using the data and the computer models, EPA predicted regionalized compliance costs and pollutant removals for the various regulatory options as defined in section XIII of this Notice. These options are comprised of three potential treatment technologies for BAT and NSPS; the three treatment technologies are:

- Improved operating performance of gas flotation technology.
- Granular filtration and subsequent surface water discharge.
- Granular filtration followed by reinjection of the produced water into any compatible geologic formation.

Similar to the costing methodology for the proposal, the per-platform capital costs for the treatment equipment and the associated annual operating, maintenance and monitoring costs (annual costs) were developed for modeled treatment systems with design capacities of 200 barrels per day (bpd), 1,000 bpd, 5,000 bpd, 10,000 bpd, and 40,000 bpd of produced water. EPA derived costs for these systems based on vendor-supplied data, industry information, and cost analyses conducted by the Energy Information Administration of the Department of Energy (DOE/EIA). Curves depicting flow rate versus cost were generated to estimate the capital and annual costs for treatment systems with capacities other than the five modeled systems for which cost data were collected.

EPA calculated total industry costs for each treatment option using the per-platform capital and annual costs and industry profiles of current and projected future production activity in three geographical offshore areas, the Gulf of Mexico, California, and Alaska. EPA did not develop specific industry costs for the Atlantic offshore areas, including Florida, because of the lack of oil and gas leasing and development in these areas. However, the costs in these regions are considered similar to those developed for offshore California because conditions in these areas are more analogous to California than to the Gulf. Because of the extensive amount of activity in the Gulf of Mexico, costs of offshore operations in the Gulf are somewhat lower than in California. EPA expects that the amount of any future activity in the Atlantic or off the coast of Florida will, at most, approach the amount of activity in California rather than the amount of activity in the Gulf. Accordingly, EPA projects that costs for California are more appropriate for projecting costs in these other areas.

For each geographical area, EPA characterized the industry as a population consisting of various platform structure types, or model platforms. A model platform was characterized by the number of available well slots on the platform. Each producing well is brought to the wellhead on the platform through a dedicated well slot. The number of well slots on a platform indicates the maximum number of producing wells. The model platforms were further subdivided based on whether they produced: (1) Oil only; (2) both oil and gas; or (3) gas only.

For each "model platform," EPA estimated the number of producing wells, the quantity of produced water generated (average and peak flow), and the cost to implement a produced water treatment system. Thus, by dividing the industry among these "model platforms," EPA derived estimates of costs and pollutant reductions.

EPA determined contaminant removals by comparing the estimated effluent levels after treatment by the BAT and NSPS treatment systems versus the effluent levels associated with a typical BPT treatment.

The computer model calculated the capital costs for each model platform in each region based on the maximum daily produced water flow rate for the given platform. The maximum daily flow rate for each modeled platform determined the required capacity of the treatment system. Interpolating along the "capital cost-flowrate" curve developed for the five modeled treatment systems, EPA determined the capital costs for each of the model platforms.

The computer model calculated the annual costs for each model platform in each region based on the average daily produced water flow rate for the given platform. The average daily flow rate for each modeled platform was used to determine the annual costs. Interpolating along the "annual cost-flowrate" curve developed for the five modeled treatment systems, EPA determined the annual costs for each of the model platforms.

a. *Gas Flotation System Capital and Annual Costs.* EPA developed gas flotation equipment costs based on direct contact with vendors and manufacturers of offshore gas flotation equipment. The packaged equipment costs are the costs for the complete gas flotation system which includes the following: a skid-mounted flotation unit, complete electrical system, oil and water outlets brought to the edge of the skid, and sufficient instrumentation for proper operation.

EPA based gas flotation space requirements on information provided by vendors and manufacturers of offshore gas flotation equipment. Some existing (BAT) platforms could incur costs for additional space such as a cantilevered deck. A cantilevered deck or wing deck can be added along one side of a platform to increase the total square footage of the platform deck. For example, a one hundred foot long cantilevered deck that extends ten feet from the edge of the existing platform deck would add one thousand square feet to the platform deck. EPA estimated the cost of additional platform space at $250 per square foot based on information obtained from industry and the Department of Energy. The actual areas required by the gas flotation systems were estimated to be twice the area of the process equipment "footprints" that were furnished by the vendors. The additional area includes sufficient space for any additional process equipment, instrumentation, and walkways. For the NSPS scenario, because new facilities can include the gas flotation equipment in the design of the platform, EPA determined that no additional platform space, such as a cantilevered deck, would be required. (In cases where new sources would be platforms that exist as of the effective date of the offshore guidelines, the cost of adding platform space has been accounted for in costing the BAT limitations for existing sources.) This methodology is identical to that presented in the proposal for other produced water treatment systems.

The annual operating and maintenance costs for the gas flotation treatment systems included energy costs, labor costs, and typical operating and maintenance costs such as polymer and/or flocculation enhancement chemicals or costs for pump and agitator maintenance and replacement.

b. *Granular Filtration Capital and Annual Costs.* The basis for the granular filtration costing is similar to that of the March 13, 1991 proposal. EPA contacted the DOE/EIA to assist in reevaluating the capital and annual costs for granular filtration systems developed for the proposal. EPA used information provided by DOE/EIA, as well as additional data collected by EPA, to update cost projections for granular filtration systems.

In revising costs, EPA no longer includes capital costs for chemical storage or electrical generators. Capital costs associated with the actual chemical injection system are included in the filtration system capital costs. Storage of chemicals is included as an annual cost. The revised costs also exclude previous cost projections for extra generators to provide power to operate treatment system modifications. The power requirements for the filtration system (approximately 30 horsepower) are minimal in comparison to the electrical generation capacity available on platforms and the existing generation capacity is considered adequate for this minimal power requirement increase. The revised costing now includes capital costs for a centrifuge to dewater the filter backwash. Backwash dewatering is necessary to minimize the space required to store the backwash and minimize the transportation and onshore disposal costs.

The revised costing assumes that additional deck space could be added to the platform for systems treating up to 40,000 barrels of produced water per day. This is based on data showing that filtration systems treating up to this volume could be installed in areas of less than 1,000 square feet. One thousand (1,000) square feet is assumed to be the largest area that can be added to a platform as a cantilevered deck. The costing presented in the March 1991 proposal had assumed that all filtration systems processing over 5,000 barrels per day (bpd) would have area requirements exceeding 1,000 square feet and thus would require construction of additional platform structures. EPA recalculated the area requirements for this final rule in consultation with DOE/EIA. Filtration systems treating more than 40,000 bpd are still considered to exceed the available space on the platform (including additional capacity from a deck addition), thus construction of a separate platform structure would be required.

c. *Reinjection Capital and Annual Costs.* Part of the basis for the reinjection costing methodology is similar to that of the granular filtration option since filtration of the produced water is typically necessary prior to reinjection. Without this pretreatment, fine solids can plug the pores of the formation, decreasing the capacity of the formation, thus preventing the reinjection of the produced water. For this costing estimation, EPA assumed that multi-media filtration would be the pre-treatment filtration technology used.

The capital costs for pumps and injection wells were revised to represent new data obtained by EPA. The DOE/EIA developed capital costs for gas turbine injection pumps which reflect more recent (1991) cost data and are slightly lower than the costs presented in the proposal. Injection well costs were revised based on data submitted with industry comments. The costs for new injection wells remained approximately the same as those presented in the proposal, but the costs to recomplete an existing dry hole changed significantly. The revised recompletion costs increased from $240,000 per well to $675,000 per well.

The revised capital costs for the reinjection option also do not include additional costs for electrical generators. Where facilities reinject, gas-powered, rather than electrical, injection pumps are generally used. Also, construction of separate platform structures to contain produced water treatment system modifications are not anticipated unless the system processes over 40,000 barrels per day of produced water. Based on EPA calculations made in consultation with DOE/EIA, area requirements for injection systems treating less than 40,000 bpd are less than 1,000 square feet and can be met by constructing platform additions such as cantilevered decks.

d. *Regional and Total Industry Costs.* The regional costs were calculated based on the per-platform capital and annual costs and the number of platforms within each geographical region. For the purposes of determining produced water compliance costs for this rule, EPA assumed that all newly installed production and development platforms would be new sources. EPA was unable to determine the extent to which existing platforms would be used to develop new hydrocarbon reserves. While an existing platform moved to a new location for development or production would also be classified as a new source, compliance costs for all existing platforms are included as BAT costs in this rule. Since BAT limitations are equal to NSPS, to ascribe both BAT and NSPS costs of compliance to one facility would double-count the costs of compliance with the rule. Also, EPA is unaware of any existing contractual obligations which could result in new production and development platforms being classified as existing sources. For this rule, new production and development platforms are included as new sources.

Based on information from the Department of the Interior and as presented in the March 1991 proposal, EPA estimated that thirty-seven percent (37%) of existing platforms currently pipe their produced water to shore for treatment. Therefore when developing the regional costs, only sixty-three percent (63%) of the total number of existing platforms and one hundred percent (100%) of new platforms were assigned offshore treatment costs. Onshore treatment costs were assigned to those facilities currently piping to shore. Onshore treatment costs are detailed in section V.B.2.e of this preamble. EPA cost projections for new platforms indicate that the cost of offshore treatment will be less than the combined cost of installing piping and establishing onshore treatment facilities. Thus, EPA assumed all new sources will treat water offshore. The total industry costs for the granular filtration and the reinjection option are the sum of the regional costs for each treatment option.

The total capital costs for gas flotation were more complicated to determine because many operators currently use the gas flotation technology to comply with the current BPT regulations. To avoid over-costing by assigning capital costs to all platforms, EPA predicted the number of existing platforms that currently have gas flotation systems and the number of platforms that will have to install new flotation systems. The following paragraphs explain EPA's basis for its estimate of the total industry costs for the gas flotation option.

EPA determined that to achieve BAT oil and grease limitations based on improved performance of gas flotation technology, operators who currently have gas flotation treatment systems would continue to use the same treatment units, although some changes to those systems or their manner of operation might be necessary. For existing platforms that do not currently have gas flotation systems and can not meet the limitations of the final rule with their currently installed treatment systems, some form of add-on treatment would be necessary. For costing purposes, EPA assumed that all facilities currently without gas flotation systems are unable to meet the BAT (or for new sources, NSPS) limitations, and that flotation units would need to be installed. This assumption does not take into consideration the fact that other treatment technologies currently used by the operators are available for use, such as parallel plate coalescers, corrugated plate interceptors, hydrocyclones, or filtration, and their use may enable operators to meet the requirements of this rule without requiring installation of flotation units. (The establishment of an effluent limitation based on a given technology does not require use of the treatment technology upon which the limitation is based.) A report prepared in 1984 for the Offshore Operators Committee (OOC) found that thirteen percent (13%) of 319 outer continental shelf (OCS) facilities surveyed at that time used flotation systems for treatment of produced water. Since that same study noted that nearly all new platforms were expected to install gas flotation systems for produced water treatment and considering that the profile would likely have changed in the years since that survey was conducted, EPA collected information from the Minerals Management Service and various industry sources to update projections of existing gas flotation systems. EPA learned from MMS, which during 1990 conducted 1,677 drilling inspections and 4,830 production inspections, that approximately thirty-five percent (35%) of the offshore facilities in Gulf of Mexico are now using gas flotation systems for produced water treatment. The distribution of gas flotation systems, in conjunction with capital and annual cost data compiled for flotation systems was used to estimate total compliance costs.

EPA calculated the BAT annual operating and maintenance (O&M) costs using the projections of existing gas flotation systems discussed above. For those platforms that already have gas flotation units installed, the annual O&M costs of complying with BAT limitations based on improved performance of gas flotation are estimated to be higher than their current annual O&M costs because of modifications and enhancements needed to improve system performance. Enhanced removals of oil and grease can be achieved by existing gas flotation systems through closer supervision of the units by the platform operators, additional monitoring of operating parameters, proper sizing of the unit to improve hydraulic loading, additional maintenance of the process equipment, and addition and/or proper usage of flocculation enhancement chemicals. These costs are incremental to the current annual O&M costs. EPA estimates that the additional labor and other improvements necessary to achieve compliance with BAT limits will approximately double the annual O&M costs for existing flotation systems currently achieving BPT quality effluent.

Existing facilities needing to install a gas flotation unit (or other technology) to comply with the limit are projected to incur costs to design and select a treatment system to meet the BAT oil and grease limit. Total annual O&M costs for existing platforms that will need to install gas flotation were determined to be approximately ten percent (10%) of the capital costs of the new flotation system. EPA notes that the BAT and NSPS limitations of the final rule are based on data from existing facilities identified as being representative of platforms having well-operated gas flotation units. Thus, although not all existing facilities with gas flotation units would be expected to already be meeting the BAT and NSPS oil and grease limits of this rule, the data shows that a portion of the industry can already comply with the limitations of this final rule without incurring an additional cost. Because EPA does not know how many of these facilities would be able to comply without incurring additional cost, no allowance is made in EPA's cost projections to exclude such facilities in determining the cost of compliance for this rule. Thus, EPA is confident that compliance costs are not underestimated and may even be overestimated by up to 20–40 percent. On balance, however, EPA believes these cost projections reasonably reflect the aggregate compliance costs for the entire subcategory.

The 1984 industry (OOC) report stated that even in the absence of produced water limitations more stringent than BPT, eighty percent (80%) of new development and production platforms would be designed with gas flotation systems for treatment of produced water. Thus, EPA based compliance cost projections on the assumption that in the absence of NSPS limitations twenty percent (20%) of new platforms would not include a flotation unit in their treatment system design. This twenty percent (20%) of new platforms are considered to incur an incremental cost to comply with NSPS limitations.

In estimating NSPS capital costs, EPA assumed that it was necessary for the operator to add a flotation system to the produced water treatment system. The entire costs for adding on such a system were used in EPA's economic impact analyses. EPA notes that although some new platforms would not have planned to install flotation systems, the platforms would have contained some other type of treatment technology and it is entirely possible that the alternative system would enable compliance without incurring additional costs to comply with the NSPS limitations. EPA also notes that by adding on a flotation system to comply with NSPS limits, the operator may actually forego installation of other produced water treatment units, with the result being that the gas flotation unit would serve as a replacement system rather than an add-on system, incurring no, or reduced, incremental costs. However, in costing this rule it has been assumed that an add-on treatment system will be required and costs of entire flotation systems for 20 percent (20%) of all new platforms have been included.

For those eighty percent (80%) of new platforms that are expected to include gas flotation in the original design, capital costs consist only of an engineering redesign cost and not a new unit cost. It is assumed that the gas flotation units included in the existing design of the new platforms were able, at a minimum, to achieve the current BPT oil and grease limitations. For these systems to achieve the more stringent limitations of this final rule, EPA assumed that there may be an additional cost to upgrade the system. A design upgrade could consist of increasing the system's retention time through increasing the cell size or the addition of another cell, maximizing separation efficiency through properly sizing rotors, gas dispersers, and chemical injection equipment, and optimizing the system's performance through the addition of state-of-the-art instrumentation and controls. This system redesign cost was estimated at fifteen percent (15%) of the NSPS flotation system capital cost.

The NSPS annual O&M costs for new platforms were calculated using the same NSPS profile used in the development of the NSPS capital costs. For the twenty percent (20%) of new platforms assumed to not already include flotation systems in the design, the annual costs are ten percent (10%) of the capital costs. However, for those new platforms that already have flotation systems in the design plans of the facility, there are no incremental annual costs for compliance with the NSPS limitations. EPA assumed that since there is a flotation system in the design of a facility, there are also annual costs associated with operation of that system in the financial projection of that project. The improved performance of that system has been accounted for by improving the design parameters of the flotation system.

Additional requirements placed on OCS sources under the recently promulgated air regulations for OCS sources (57 FR 40792) were also considered in developing compliance costs for this rule. Emissions offset costs were calculated for all facilities located off the Southern California coast, since this OCS planning area is adjacent to an onshore nonattainment area. Offset costs are assumed to be an annual expense and are included in the annual O&M costs for the produced water treatment options. Offset costs were calculated for nitrogen oxide and hydrocarbon emissions were calculated for this regulation based on annual costs of $15,000 per ton of nitrogen dioxide and $5,000 per ton of hydrocarbons.

e. *Onshore Treatment Costs*. EPA assumed that those facilities currently piping produced water to shore for treatment would continue to do so and no additional offshore treatment would be necessary. Since they are treating and discharging produced water which originated in the offshore subcategory, the onshore treatment facilities are required to meet the oil and grease limitations of this final rule and are expected to achieve compliance through either upgrading existing equipment or installing new treatment equipment. For this costing exercise, EPA evaluated the costs for installing new equipment at the onshore treatment facilities. For the 37 percent of the facilities piping to shore for treatment, EPA developed costs for onshore treatment by gas flotation, granular filtration, and reinjection technologies.

The onshore treatment costs were evaluated for both the BAT and NSPS scenarios. However, for the NSPS scenario, EPA projects that the cost to install piping to the offshore facility would greatly exceed the costs of installing the necessary treatment control technology onsite at the offshore platforms. Thus, EPA predicts that no new sources will pipe produced water to shore for treatment. Although EPA was unable to determine the extent to which it might happen, it is possible that in some instances new sources may reduce onshore treatment costs by sharing an existing pipeline to shore.

The basis for the onshore treatment system costs are similar to the offshore per-platform system costs, although there are a few exceptions. The exceptions are: (1) The offshore installation factor of 3.5 was not used (The multiplier is applied to onshore costs to account for the increased cost of transporting and installing equipment offshore. The multiplier is identical to that value used at proposal and was derived based on information supplied by DOE/EIA, equipment vendors, service providers, and other industry commenters); (2) there were no costs for platform additions; and (3) no centrifuge cost was assigned for the onshore filtration or reinjection options. EPA assumed that a centrifuge would be unnecessary to dewater the filter backwash because adequate space would be available at an onshore treatment facility to capture, settle and store backwash volumes from the granular filter.

3. Membrane Filtration

EPA reexamined the applicability of membrane filtration technology for the treatment of produced water as a result of additional data obtained on the technology and numerous comments on the March 13, 1991 proposal. In April 1991, EPA conducted a sampling program of the only full-scale ceramic membrane filtration unit processing oil field produced water in the United States.

EPA's reevaluation of membrane filtration technology concluded that membrane filtration technology is still in the development phase for applications in the treatment of produced water. EPA's sampling program clearly indicated that the technology is capable of substantially reducing the quantities of soluble and insoluble organics found in produced water. However, despite the outstanding pollutant removal performance of the ceramic membrane filtration unit, the unit experienced operating problems which preclude long-term continuous treatment of the entire produced water stream to the effluent levels presented in the proposal. The sampling program brought to light several operational difficulties that, according to the operator, are experienced with the full scale unit. The most significant problem experienced with that unit was fouling of the membrane. The operator identified several conditions responsible for significant fouling of the membrane surface. These conditions are: sea water in the produced water stream from the deck washdown system, high oil and grease loadings on the membrane during upsets, and the presence of production chemicals in the produced water. Membrane fouling results in a significant reduction of flux across the membrane and ultimate shutdown of the unit for chemical cleaning. As a result, the unit was operated at twenty percent (20%) of the rated design capacity and shutdowns for cleaning were reported to be frequent. An additional adverse effect was reported to result from recycling of the oil phase of the membrane retenate stream back into the produced water treatment system. Chemicals added to the filtration unit which become entrained in the oil phase reportedly result in decreased separation efficiency in the upstream separation unit (heater-treater).

EPA also received several comments regarding the proposal's selection of membrane filtration as a preferred technology. These comments paralleled EPA's conclusion that membrane filtration is not technically available as a BAT or NSPS treatment option at this time. The commenters provided data obtained from the same full scale system evaluated by the EPA and a pilot scale unit operating in the Gulf of Mexico. Commenters also provided information on a polymeric membrane filtration pilot unit being tested in the North Sea and a literature study which reviewed data furnished by manufacturers and oil companies regarding five different membrane filtration systems.

4. Produced Water Pollutant Loadings

Similarly to the March 1991 proposal, pollutant removals for the different regulatory options of the final rule were determined by comparing the estimated effluent levels of pollutants after treatment by the BCT/BAT/NSPS treatment system (improved performance of gas flotation, filtration, or reinjection) versus the effluent levels of pollutants associated with a typical BPT treatment (gas flotation or gravity separation).

In the March 1991 proposal, EPA characterized BPT treatment using data from the 30 Platform Study. Comments received subsequent to the proposal stated that certain pollutants found present in other studies of produced water effluent had been excluded by EPA and resulted in pollutant removals being underestimated. Several commenters also disputed the presence of one pollutant included in EPA's BPT characterization.

In response to the comments received regarding BPT characterization, EPA developed an expanded data set based on published studies which included characteristics of produced water. As a result of this reanalysis, one pollutant, bis(2-ethylhexyl)phthalate, was deleted and anthracene, benzo(a)pyrene, chlorobenzene, di-n-butylpthalate, total xylenes, cadmium, lead, nickel and radium were added to the list of pollutants present in produced water BPT effluent.

Based on the presence of the pollutants in BPT effluent, BAT and NSPS pollutant reductions were reassessed for granular filtration systems based on "three facility study" data. Data from gas flotation units determined to be demonstrating improved performance in the 30 Platform Study were the primary basis for determining pollutant reductions from improved performance of gas flotation.

C. Produced Sand

The methodology used to determine compliance costs for the zero discharge limitation for produced sand is based on produced sand generation rate estimates, onshore disposal costs at permitted exploration and production waste disposal facilities, and onshore disposal costs at permitted low level radioactivity disposal facilities. EPA determined that no direct marine transportation costs (from the platform to shore) would be associated with the zero discharge requirement based on data from the Offshore Operators Committee (OOC) produced sand survey and additional information on produced sand handling and disposal practices submitted by the OOC. This information indicates that produced sand collected regularly through operation of desanders and blowdowns through valves on vessels accounts for less than ten percent of the volumes of sand collected annually. The majority of sand is collected during scheduled cleanouts. The information also indicates that ninety percent (90%) or more of the produced water treatment system cleanouts produce less than 100 barrels of produced sand per cleanout. The cleanouts occur during a platform shutdown and the typical cleanout cycle is once every three to five years. Therefore, EPA concluded that the volume of produced sand collected from vessel blowdowns is small enough that operators are able to use the supply boats that service offshore platforms on a frequent and regular basis, rather than contract for dedicated vessels to transport the waste to shore. The produced sand collected during tank and vessel cleanouts are typically small volumes that can be transported to shore using either the regularly scheduled supply boats or the work boats chartered to support the sand removal or other general maintenance during the platform shutdown.

Data evaluated by EPA for this rule indicates a generation rate of one barrel of produced sand for every 2,000 barrels of oil produced. EPA calculated produced sand volumes using peak year oil production estimates from the Minerals Management Service. Data from the produced sand survey indicated that, in 1989, thirty-four percent (34%) of the produced sand generated was hauled to shore for disposal. The industry does not incur any incremental compliance costs under this rule for that portion of the produced sand which is already being disposed of onshore. For determining the incremental costs of the zero discharge requirement of this rule, EPA based its costs projections on the produced sand volume being discharged offshore (66 percent of all produced sand generated).

In December 1991, the MMS Gulf of Mexico Regional Office issued a Letter to Lessees (LTL) providing guidance limiting ocean discharges of produced sand contaminated with naturally occurring radioactive materials (NORM). This LTL notified operators that, under authority provided MMS, discharges of produced sand with a radiation dose rate greater than 25 microroentgen per hour would not be approved. NORM is formed by co-precipitation of soluble radium from the formation water (produced water) along with barium sulfate, calcium carbonate, and other scale-producing constituents. These precipitates (as scale) collect in the separator tank bottoms (solids) along with the produced sand. Radionuclide data included in the produced sand survey indicated that NORM levels for some of the produced sand volumes previously discharged to the ocean (in 1989) exceed the current MMS guidelines and would now require onshore disposal. Therefore, EPA notes that the percentage of produced sand being discharged to sea may actually be less than 66 percent of the total volume generated. Since the MMS guidelines are interim guidance and could conceivably be withdrawn, EPA has continued to project compliance costs based on transporting 66 percent (66%) of produced sand generated annually to shore for disposal. The possible presence of NORM in produced sand did not drive EPA's determination that zero discharge is appropriate for this wastestream; however, because some produced sand contains NORM, EPA did consider the presence of NORM for the purpose of estimating compliance costs for the zero discharge limitations.

EPA used the data on radioactivity levels in produced sand to estimate average radium concentrations for the produced sand wastestream. The radioactivity data submitted provides either exposure rates expressed in microRoentgens per hour (microR/hr) or concentrations expressed in picocuries per gram (pCi/g). Average radium concentrations and the incremental increase in the volume of produced sand hauled to shore provided the basis for estimating radium removals. For the produced sand volumes considered to have elevated NORM levels (25 percent of produced sand according to OOC data), EPA assigned costs for disposal at low level radioactivity disposal facilities. Produced sand containing NORM above these levels may not actually require disposal at low-level radioactivity disposal facilities. To ensure compliance costs for zero discharge were not underestimated, however, EPA considers using this methodology to be an appropriate basis to project incremental costs of this rule. For the remaining volumes of produced sand (without elevated NORM levels) brought to shore for disposal, EPA assigned costs for disposal at licensed commercial oilfield waste disposal facilities.

The pollutant loadings calculations also estimated reductions in discharges of oil and total suspended solids. The loadings were calculated based on the reductions in produced sand discharges to the ocean. Oil removals were calculated using an average oil content in washed produced sand of 1.63 percent based on data submitted in response to the proposal.

D. Well Treatment, Completion and Workover Fluids

This rule requires well treatment, completion and workover fluids to meet oil and grease limitations based on the technology of cotreating these fluids with the produced water treatment system. Based on information provided by industry commenters, the technology of commingling these fluids with produced water is available. Treating these fluids with produced water is considered to incur no, or minimal, additional compliance costs. Costs to operate properly the produced water treatment system and monitor for compliance are accounted for in the compliance cost projections for produced water. Some facilities may be unable to treat well treatment, completion and workover fluids with the produced water and would incur compliance costs under this rule. The following paragraphs discuss the costing methodology for those facilities.

EPA used information submitted by industry commenters to determine most multiple-well facilities are able to treat the treatment, completion and workover fluids in the produced water treatment system. Because facilities with fewer than ten producing wells generate a relatively low volume of produced water, there is a potential for upset of the treatment systems due to inadequate equalization of wastewaters. For facilities with fewer than ten well slots, EPA developed compliance costs based on the technology of capturing and transporting the wastes to shore for treatment and/or disposal. No additional compliance costs are projected for the offshore facilities (37 percent of existing facilities) that pipe their produced water to shore for treatment. Because of the large volumes of produced water treated at these onshore sites, EPA believes the treatment, completion and workover fluids could be commingled with the produced water wastestream without causing treatment system upset. The onshore facility can adequately treat the occasional slug of treatment fluids and still maintain compliance with BAT and NSPS limitations.

Based on industry comments, well workovers or treatment jobs were determined to occur, on average, approximately every four years. According to industry comments and literature, workover fluids are typically reused at least once and treatment fluids can only be used once. The workover and treatment fluids volumes and onshore disposal costs estimates are averages based on the fifteen year period evaluated for this rule. Average yearly disposal costs were developed because workover and treatment fluids volumes are not generated, and hence costs are not incurred, until four years after well completion and subsequently every four years thereafter. The well completion fluids volumes and onshore disposal cost estimates are based on a yearly average projection of wells drilled over the fifteen years following promulgation.

The typical discharge volumes associated with workover, treatment, and completion have been revised since the proposal based on industry comments. The volume of workover and completion fluids generated is estimated to average 300 barrels per well. This volume accounts for a preflush and postflushing of the well and weighting fluid for a 10,000 foot well. The average volume of treatment fluids generated is 250 barrels per well.

EPA believes that there will be no cost for the containment of the spent fluids prior to transporting them to shore for disposal because during well treatment, workover, or completion, storage tanks currently exist on the platform or on tending workboats for fluid storage and separation. (To ensure compliance with the current BPT limitations prohibiting discharge of free oil, operators must maintain the capability to capture fluids which, if discharged, would cause a sheen on the receiving waters.) EPA believes that these tanks would provide adequate storage for the time between capturing the fluids as they come out of the well and the time of transporting the fluids to shore.

EPA also did not assign any incremental costs to the transportation of the fluids to shore. Based on comments from industry, EPA determined that the volumes would be small and the workboats tending the rig (for treatment, completion, or workover evaluations) or regularly scheduled supply boats would have adequate space to transport the containers of spent fluids. As discussed in the above paragraph, EPA determined that the platforms would have adequate space for storage of the spent fluids for the periods when the supply boats are not scheduled for the platform or when offloading to the supply boats is infeasible due to weather conditions.

To estimate compliance costs for those facilities unable to commingle fluids with the produced water, EPA determined the most common method of onshore treatment of spent fluids to be injection into underground formations at a centralized treatment facility. The disposal costs are estimated to be $12 per barrel and are based on the costs of transporting the fluids from an inland port transfer station to the disposal facility, solids removal if necessary, and injection into underground formations.

E. Non-Water Quality Environmental Impacts

The evaluation of non-water quality environmental impacts for this final rule generally follows the methodology presented by EPA in the March 1991 proposal. This methodology was patterned after calculations performed by Walk-Haydel and Associates, and submitted by the American Petroleum Institute (API) as part of API's comment submission on the 1988 Notice of Availability. These impacts were reassessed based on public comments on the March 1991 proposal. The manner in which those comments were considered and how they affected the non-water quality environmental impact analysis are presented in the following discussion.

1. Drilling Fluids and Drill Cuttings

Several commenters disputed EPA's estimates of drilling waste volumes requiring onshore disposal, as well as the manner in which these wastes would be transported and the adequacy of available disposal sites. Generally, these comments either: (1) Noted the potential for improved solids control equipment to reduce drilling waste volumes; (2) contended that EPA's assumption regarding the number of vessels necessary for transporting the drilling wastes was an overestimate; (3) contended that EPA had underestimated the drilling waste volumes requiring onshore disposal; or (4) stated that projected sites for disposal would encounter difficulties in obtaining operating permits. For this final rule, EPA reassessed estimates of the incremental increase in the volume of drilling fluids and drill cuttings requiring onshore disposal under the various options under consideration, reevaluated solids control equipment practices and supply boat utilization, updated estimates of the onshore disposal capacity for oilfield wastes, and reassessed the assumptions and methodologies used in determining energy requirements and air emissions. EPA also took into account the Clean Air Act Amendments of 1990 (and implementing regulations issued September 4, 1992 at 57 FR 40792) establishing new limitations on emissions of air pollutants from OCS sources.

2. Produced Water

Energy requirements and air emissions associated with the produced water treatment options were reassessed for the final rule. At proposal, energy requirements were calculated based on determining the total pressure drop across a treatment unit, converting this differential pressure value to a power requirement (horsepower) needed to operate the treatment system, then identifying fuel consumption. In reevaluating the non-water quality environmental impacts, EPA noted that energy requirements for the granular filtration option were underestimated and reinjection option fuel requirements were overestimated. To estimate more accurately the energy requirements for the final rule, EPA recalculated fuel needs based on the power requirements for each of the various capacities (produced water flowrates) of the modeled treatment systems.

EPA's revised calculations also based fuel usage calculations on reinjection pumps driven by natural gas turbines instead of electric-driven pumps, which the calculations for the proposal were based upon. Gas-driven pumps are preferred offshore because the platforms typically have gas production on-site which serves as the fuel source. (Electrical reinjection pumps require more fuel than gas-driven pumps because of an extra energy conversion step.)

F. Industry Profile

The location, size, and number of existing platforms has been updated since the proposal in response to comments. First, information was gathered to account for current activity in State waters of the offshore subcategory in the Gulf of Mexico. Second, the Pacific profile was re-evaluated in light of comments. The new information is discussed in section III.B.2 of this notice.

Table 3 presents the estimated number of existing producing structures that are projected to incur costs under today's rule. Approximately 8 percent of the existing structures estimated to bear BAT costs lie within the 3-mile boundary.

Table 4 presents the number of new wells projected to be drilled annually by geographic region and distance from shore. The estimates include exploratory, development and production wells. Both productive and non-productive (dry holes) wells are included.

Table 5 presents the total number of new structures estimated to be installed during the 15-year period following promulgation. Fourteen percent of new structures are projected for installation within 3 miles from shore.

TABLE 3.—EXISTING STRUCTURES IN OFFSHORE WATERS

[Estimated to bear BAT costs]

	Distance from shore (miles)		
	0–3	>3	Total
Gulf of Mexico	201	2,316	2,517
California	10	22	32
Alaska	0	0	0
Total	211	2,338	2,549

Note: Two existing facilities offshore Alaska currently reinject produced water under state requirements. No compliance costs have been estimated for the two Alaskan facilities since any costs incurred under this rule would be minimal.

TABLE 4.—AVERAGE ANNUAL NUMBER OF WELLS DRILLED, BAT/BCT AND NSPS

[15 Years following promulgation]

	Distance from shore (miles)				
	0–3	3–4	4–8	>8	Total
Gulf of Mexico	60	12	64	579	715
California	0	0	29	3	32
Alaska	([1])	([1])	([1])	([1])	12
Total	....	....	....	....	759

[1] Not presented because Alaska excluded from zero discharge requirement for drilling fluids and drill cuttings.

TABLE 5.—TOTAL PROJECTED NEW FACILITIES

[15 Years following promulgation]

	Distance from shore (miles)			
	0–3	3–4	>4	Total
Gulf of Mexico	102	38	615	755
California	0	0	0	0
Alaska	2	0	2	4
Total	104	38	617	759

VI. Summary of the Most Significant Changes From the Proposal

This section briefly identifies the most significant changes from the proposal. More detailed discussion of these changes, and identification and discussion of other issues are included in other sections of this notice, the Development Document, the Economic Impact Analysis, and the record for this rule.

A. Drilling Fluids and Drill Cuttings

1. BCT

In the March 1991 proposal, EPA's preferred option for BCT control of drilling fluids and drill cuttings required zero discharge for wells drilled at a distance of four miles or less from shore. Discharges from wells drilled at a distance greater than four miles from shore were proposed to be limited by a prohibition on the discharge of free oil, as determined by the static sheen test. Wells drilled in the Alaska region were proposed to be excluded from the zero discharge limitation, and instead comply with the no free oil limitation.

For this final rule, the delineation for determining the zone of zero discharge is being set at a distance of three miles from shore. Drilling fluids and drill cuttings from wells drilled by existing sources at a distance of 3 miles or less from shore will be prohibited from discharge to the surface waters of the U.S. Discharges of drilling wastes (fluids and cuttings) from wells drilled beyond this distance will be prohibited from discharging free oil. As proposed, wells drilled off Alaska will be excluded from the zero discharge and will instead comply with the no free oil limitation.

2. BAT and NSPS

In the March 1991 proposal, EPA's preferred option for BAT and NSPS control of drilling fluids and drill cuttings was similar to the preferred BCT control and required zero discharge for wells drilled at a distance of four miles or less from shore. Additional requirements for control of priority and nonconventional pollutants in drilling fluids and drill cuttings were proposed for those wells drilled at a distance greater than four miles from shore and were as follows: (1) Toxicity limitation set at 30,000 ppm in the suspended particulate phase; (2) a prohibition on the discharge of detectable amounts of diesel oil used either for lubricity or spotting purposes; (3) no discharge of free oil based on the static sheen test; and (4) limitations for cadmium and mercury in the drilling fluids and drill cuttings at 1 mg/kg each in the whole drilling fluid at the point of discharge. All wells drilled in the Alaskan region were proposed to be excluded from the zero discharge limitation; instead, discharges from wells off Alaska were proposed to be controlled by the limitations on mercury and cadmium, toxicity, and diesel and free oil.

NSPS and BAT limitations of this final rule differ from the proposed limitations in the following manner. First, as established for BCT, the prohibition on discharges of drilling fluids and drill cuttings is being set at a distance of three miles from shore. Second, for reasons discussed in section VII.B.3 of this notice, the term "in detectable amounts" has been deleted from the limitation prohibiting discharges containing diesel oil. Third, instead of the proposed "end-of-pipe" limitation on cadmium and mercury content in the whole drilling fluid, EPA is limiting these metals at 3 mg/kg for cadmium and 1 mg/kg for mercury in the stock barite. Discharges beyond 3 miles from shore, as well as all discharges of drilling wastes off Alaska, will be required to comply with the limitations on mercury and cadmium, toxicity, and diesel and free oil.

B. Produced Waters

The BCT limitation of this final rule is unchanged from the proposal and is being established equal to current BPT limits (48 mg/l monthly avg., 72 mg/l daily max.). In March 1991, EPA proposed establishing oil and grease limitations for BAT and NSPS based on membrane filtration technology (7 mg/l monthly average, 13 mg/l daily maximum) for produced water discharges located within four miles from shore, and setting BAT and NSPS equal to the current BPT limitations for discharges beyond that distance. Alternatively, EPA was also considering setting the limitations for those facilities within four miles of shore based on granular filtration technology (16 mg/l monthly avg., 29 mg/l daily max.). In this final rule, EPA is requiring all discharges of produced water to comply with BAT and NSPS oil and grease limitations of 42 mg/l daily maximum and 29 mg/l monthly average based on improved performance of gas flotation technology.

C. Produced Sand

The BAT and NSPS limitations for this wastestream remain unchanged from the proposed limitation of zero discharge. BCT in this final rule will prohibit all discharges of produced sand.

D. Deck Drainage

The BCT limitation of this final rule is unchanged from the proposal and is equal to the BPT limitation of no discharge of free oil. In March 1991, EPA proposed establishing oil and grease limitations for BAT and NSPS control of this wastestream based on commingling deck drainage with the produced water treatment system. The preferred option for control of deck drainage at proposal was to set the BAT and NSPS limits equal to those proposed for produced water. EPA also proposed setting BAT and NSPS equal to BPT (56 FR 10695 and 56 FR 10698). In the final rule, EPA is setting BAT and NSPS limitations equal to the current BPT limitations prohibiting discharge of free oil.

E. Well Treatment, Completion, and Workover Fluids

The BCT limitation of this final rule is unchanged from the proposal and is equal to the existing BPT limitation of no discharge of free oil. In March 1991, EPA proposed NSPS and BAT limitations prohibiting discharge of well treatment, completion and workover fluids which surfaced from the well as a discrete fluid slug, along with a buffer volume preceding and following that fluid slug. For those treatment, completion and workover fluids surfacing intermixed, or commingled, with produced water, EPA proposed establishing oil and grease limitations for BAT and NSPS control based on treatment by the produced water treatment system. The limitations were proposed to be equivalent to those proposed for produced water.

In this final rule, EPA is deleting the zero discharge requirement for discrete fluid slugs. BAT and NSPS limitations are being set equal to the BAT and NSPS limitations of this rule for produced water which is based on improved performance of gas flotation (29 mg/l monthly avg, 42 mg/l daily max).

F. Domestic Waste

In March 1991, EPA proposed prohibiting discharges of floating solids and foam. In addition to the limitations proposed, EPA is incorporating limitations on discharges of garbage and plastics, as required by 33 CFR Part 151. Discharges of foam will be prohibited under BAT as well as NSPS.

G. Sanitary Waste

The BCT and NSPS limitations for this wastestream remain unchanged from proposal and are equal to existing BPT requirements. BAT is not being promulgated for these wastes.

VII. Basis for the Final Regulation—Drilling Fluids and Drill Cuttings

A. BCT

Section 304(b)(4)(B) of the CWA requires EPA to take into account a variety of factors, in addition to the BCT cost test discussed below, in establishing BCT limitations. These additional factors include "non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate." EPA conducted an investigation into both the impacts of transporting drilling wastes and the availability of land for drilling waste disposal (see section VII.A.4). These non-water quality environmental impacts and energy requirements and their effect on the control of drilling fluids and drill cuttings covering existing and new sources are discussed below. Also, EPA considered other factors such as administrative burden and enforcement issues in evaluating BCT options.

1. BCT Methodology

The methodology for determining "cost reasonableness" was proposed by EPA on October 29, 1982 (47 FR 49176) and became effective on August 22, 1986 (51 FR 24974). These rules set forth a procedure which includes two tests to determine the reasonableness of costs incurred to comply with candidate BCT technology options. If all candidate options fail any of the tests, or if no candidate technologies more stringent than BPT are identified, then BCT effluent limitations guidelines must be set at a level equal to BPT effluent limitations. The cost reasonableness methodology compares the cost of conventional pollutant removal under the BCT options considered to be the cost of conventional pollutant removal at publicly owned treatment works (POTWs).

BCT limitations for conventional pollutants that are more stringent than BPT limitations are appropriate in instances where the cost of such limitations meet the following criteria:

• *The POTW Test:* The POTW test compares the cost per pound of conventional pollutants removed by industrial dischargers in upgrading from BPT to BCT candidate technologies with the cost per pound of removing conventional pollutants in upgrading POTWs from secondary treatment to advanced secondary treatment. The upgrade cost to industry must be less than the POTW benchmark of $0.46 per pound ($0.25 per pound in 1976 dollars indexed to 1986 dollars).

• *The Industry Cost-Effectiveness Test:* This test computes the ratio of two incremental costs. The ratio is also referred to as the industry cost test. The numerator is the cost per pound of conventional pollutants removed in upgrading from BPT to the BCT candidate technology; the denominator is the cost per pound of conventional pollutants removed by BPT relative to no treatment (i.e., this value compares raw wasteload to pollutant load after application of BPT). The industry cost test is a measure of the candidate technology's cost-effectiveness. This ratio is compared to an industry cost benchmark, which is based on POTW cost and pollutant removal data. The benchmark is a ratio of two incremental costs: the cost per pound to upgrade a POTW from secondary treatment to advanced secondary treatment divided by the cost per pound to initially achieve secondary treatment from raw wasteload. The result of the industry cost test is compared to the industry Tier I benchmark of 1.29. If the industry cost test result for a considered BCT technology is less than the benchmark, the candidate technology passes the industry cost-effectiveness test. In calculating the industry cost test, any BCT cost per pound less than $0.01 is considered to be the equivalent of de minimis or zero costs. In such an instance, the numerator of the industry cost test and therefore the entire ratio are taken to be zero and the result passes the industry cost test.

These two criteria represent the two-part BCT cost reasonableness test. Each of the regulatory options was analyzed according to this cost test to determine if BCT limitations are appropriate.

2. BCT Options Considered

Following a review of the comments and data received in response to the March 1991 proposal, EPA modified the control and treatment options in developing the final rule. The following BCT effluent limitations options for drilling fluids and drill cuttings were evaluated for cost-reasonableness by the

POTW and the industry cost-effectiveness tests:

"3 Mile Gulf/California"—All regions except offshore Alaska would be prohibited from discharging drilling fluids and drill cuttings from all wells located within three miles from shore. All wells located beyond three miles from shore, as well as all wells being drilled off of Alaska, would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

"8 Mile Gulf/3 Mile California"—Zero discharge for all wells in the Gulf of Mexico located within eight miles from shore and zero discharge for all wells offshore California located within three miles from shore. All wells located beyond eight miles from shore in the Gulf of Mexico, beyond three miles from shore off California, and all wells drilled offshore Alaska would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation.

"Zero Discharge Gulf/California"—Zero discharge for all wells located in the Gulf of Mexico and offshore California. All wells being drilled offshore Alaska would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation.

EPA also evaluated the compliance costs and non-water quality environmental impacts for discharge prohibitions at four and six miles from shore in considering the appropriateness of the three- and eight-mile drilling activity profiles. These other options are discussed in detail in the Development Document for the final rule. "Miles" as used in this preamble and the regulation in reference to BCT, BAT and NSPS limitations for drilling fluids and drill cuttings refers to nautical miles. Although it is not a conventional pollutant, as is oil and grease, EPA is limiting free oil as a surrogate for oil and grease under BCT in recognition of its previous use under BPT.

In referring to the options considered for control of drilling fluids and drill cuttings, the Gulf of Mexico, California and Alaska regions are used in the option descriptions and accompanying discussion. Use of the word "Gulf" means any offshore location other than Alaska and California. EPA uses the term "Gulf" as a "shorthand" way of referring to regulatory options and does not exclude other geographic areas from coverage under this rule. For the BCT, BAT and NSPS limitations under this rule, all offshore areas other than offshore California and Alaska would be required to comply with the limitations established for the Gulf of Mexico.

For the purposes of this rule, EPA determined that reinjection of drilling wastes into underlying formations at offshore platforms was not an available technology at this time. Although this technology has been demonstrated at some onshore sites in Alaska and the Gulf of Mexico region, the size of the equipment required to perform these operations and questions regarding the feasibility of reinjecting a high solids slurry into underlying formations throughout the offshore regions affected by this rule currently preclude widespread application offshore.

The removals of TSS and oil and grease are the only conventional pollutants selected in calculating the BCT cost reasonableness tests for drilling wastes. BOD was not used because it was not a parameter normally measured in wastewaters from this industry since it is associated with the oil content. The use of both BOD and oil (or oil and grease) would essentially result in double-counting pollutant removals, thus giving erroneous results. (See 47 FR 49181 and 51 FR 24976)

Comments were submitted to EPA regarding specific situations in Alaskan waters (State and Federal waters off of Alaska) which make compliance with a zero discharge requirement based on transporting drilling wastes to shore for treatment and/or disposal difficult. Reasons for this primarily relate to the severe weather conditions. Because of sea ice, tugs and barges can only be used for 4 months in the summer during open-water/broken ice season. In addition, winter snow and fog conditions severely restrict visibility. White-out conditions occur restricting air and water travel. Other considerations which hinder compliance with the zero discharge requirement are the long distances (both offshore and onshore) required to transport wastes to areas which may be suitable for land disposal and the lack of permitted land disposal facilities. For these reasons, EPA is excluding Alaskan waters from the zero discharge requirement. All drilling fluids and drill cuttings discharges from existing sources off Alaska will be required to comply with the BCT limitation prohibiting the discharge of free oil (measured by the static sheen test), as well as the BAT limitations on free oil, diesel oil, toxicity, cadmium and mercury. All discharges of drilling fluids and drill cuttings from new sources off Alaska must comply with NSPS limits on free oil, diesel oil, toxicity, cadmium and mercury.

3. BCT Cost Test Calculations

a. *Drilling Fluids.* Using the volumes of drilling fluids projected by the computer model for each geographic region, it was estimated that offshore drilling activity annually generates a total of 944,364,000 lb/yr of conventional pollutants (TSS and oil) in the drilling fluids wastestream. Applying the BPT restrictions on free oil, it was estimated that under BPT a total of 47,807,000 lb/yr of conventional pollutants are removed from this waste stream for onshore disposal, at a cost of $7,152,000 per year (1986 dollars). Dividing the cost by pollutant removal, the BPT cost per pound of conventional pollutant removal for drilling fluids is $0.1496 per pound (1986 dollars). This value is the denominator of the industry cost-effectiveness test (the second part of the two part BCT cost-reasonableness test).

$$\text{BPT Result (\$/lb)} = \frac{\$7{,}152{,}000}{47{,}807{,}000 \text{ lbs}}$$

=$0.1496 per pound (1986 dollars)

The POTW test (first part of the two part BCT cost-reasonableness test) is calculated by comparing the cost per pound of conventional pollutants removed in upgrading from BPT to the BCT candidate technologies. The "3 Mile Gulf/CA" option for BCT, in relation to BPT requirements on drilling fluids, is projected to remove an additional 71,292,000 pounds of conventional pollutants from the drilling fluids wastestream at an incremental cost of $5,697,000 (1986 dollars). These BCT incremental compliance costs and pollutant removals are due to onshore disposal of drilling fluids within three miles from shore (costs and pollutant removals associated with the no free oil limit beyond three miles from shore are attributed to BPT limitations and are not counted again under BCT). Since the cost reasonableness methodology is concerned with the cost of conventional pollutant removal under BCT as it is applied incrementally to BPT, the effects of existing NPDES permit limitations which may be more stringent than BPT (such as toxicity, diesel and metals limits for the drilling fluids) are not considered for the cost-reasonableness tests. These BCT cost tests focus exclusively on the incremental costs/removals from raw wasteload to BPT, and the incremental costs/removals from BPT to BCT. Dividing the BCT costs by the conventional pollutant removals provides a POTW test result of $0.0799 per pound. Since the POTW test result is less than $0.46 per pound (1988 dollars), the result passes the POTW test.

$$\text{POTW Test Result (\$/lb)} = \frac{\$5{,}697{,}000}{71{,}292{,}000 \text{ lbs}}$$

=\$0.0799 per pound (1986 dollars)

The industry cost test compares the result of the POTW test to the cost per pound of the BPT limitations. For the "3 Mile Gulf/CA" option, the test result for drilling fluids is 0.53.

Industry Cost Test=

$$\frac{\text{POTW Test Result}}{\text{BPT Result (\$/lb)}} = \frac{0.0799}{0.1496} = 0.53$$

Since the test result is less than 1.29, the result passes the industry cost-effectiveness test. Since the BCT candidate option passes both tests, it is found to be cost-reasonable.

Additional discussion of the compliance costs and BCT cost tests are provided in the Development Document. The results of the BCT cost reasonableness test for the candidate options for drilling fluids are presented in Table 6. All BCT options considered for drilling fluids pass both cost-reasonableness tests.

TABLE 6.—BCT COST TEST RESULTS FOR DRILLING FLUIDS

BCT candidate options	Conventional pollutants removed[1] (MM lb/yr)	Regulatory compliance cost[1] (MM \$/yr) (1986 \$)	POTW cost test (1986 \$/lb)	Industry cost test
3 Mile Gulf/CA	71.3	5.7	0.08	0.53
8 Mile Gulf/3 Mile CA	161.6	18.1	0.11	0.75
Zero Discharge Gulf and CA	879.1	116.8	0.13	0.89

[1] Incremental to BPT.

b. *Drill Cuttings.* Using the volumes of cuttings predicted by the computer model for each geographic region, it was estimated that the offshore drilling activity annually generates a total of 846,341,000 lb/yr of conventional pollutants (TSS and oil) in the drill cuttings wastestream. Applying the BPT restrictions on free oil, it was estimated that, under BPT limitations a total of 9,381,000 lb/yr of conventional pollutants are removed from this waste stream for onshore disposal at a cost of \$635,000 per year (1986 dollars). Dividing the cost by pollutant removal, the BPT cost per pound of conventional pollutant removal for drill cuttings is \$0.0677 per pound (1986 dollars). The results of the BCT cost reasonableness test for the candidate options for drill cuttings are presented in Table 7. All BCT options considered for drill cuttings pass both cost reasonableness tests.

TABLE 7.—BCT COST TEST RESULTS FOR DRILL CUTTINGS

BCT candidate options	Conventional pollutants removed[1] (MM lb/yr)	Regulatory compliance cost[1] (MM \$/yr) (1986 \$)	POTW cost test (1986 \$/lb)	Industry cost test
3 Mile Gulf/CA	70.5	3.3	0.05	0.69
8 Mile Gulf/3 Mile CA	155.2	7.5	0.05	0.72
Zero Discharge Gulf and CA	825.3	41.0	0.05	0.73

[1] Incremental to BPT.

4. Non-Water Quality Environmental Impacts and Other Factors

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 these regulations on air pollution, solid waste generation and management, consumptive water use, and energy consumption. Because the technology basis for the limitation on drilling fluids and drill cuttings requires transporting the wastes to shore for treatment and/or disposal, adequate onshore disposal capacity for this waste is critical in assessing the options. Safety, impacts of marine traffic on coastal waterways, and implementation considerations such as administrative burden and enforcement were other factors also considered. EPA evaluated the non-water quality environmental impacts on a regional basis because the different regions each have their own unique considerations (e.g., air emissions are a particular concern in Southern California, while availability of disposal sites is more limiting for the Gulf of Mexico). Although not specifically detailed in the discussion below, the non-water quality environmental impacts associated with the projected future drilling and production activities in regions other than the Gulf of Mexico, California, and Alaska have been considered acceptable.

The control technology basis for compliance with the options considered for the drilling fluids and drill cuttings wastestreams is a combination of product substitution and/or transportation of drilling wastes to shore for treatment and/or disposal. The non-water quality environmental impacts associated with the treatment and control of these wastes are summarized in Table 8.

TABLE 8.—NON-WATER QUALITY ENVIRONMENTAL IMPACTS DRILLING FLUIDS AND DRILL CUTTINGS

Options	Volume of barged waste (bbl/yr)	Air emissions (tons/yr)	Fuel requirements (bbl diesel/yr)
3 mile Gulf/CA	690,800	298	34,900
8 mile Gulf/3 mile CA	1,374,300	466	55,700
Zero Discharge Gulf and CA	6,811,400	1,798	221,400

Note: All values presented incremental to current industry practice.

a. *Solid Waste Generation and Management.* The regulatory options considered for this rule will not cause the generation of additional solids as a result of the treatment technology. However, used drilling fluids and drill cuttings contain high levels of solids, and considerable volumes of these wastes will be disposed of onshore instead of being discharged at the drilling sites under this final rule.

EPA estimates that drilling activity in the offshore subcategory generates approximately 7.7 million barrels per year of drilling wastes (drilling fluids and drill cuttings). Of that volume, it is estimated that about 760,000 barrels per year of drilling wastes already undergo onshore disposal to comply with current NPDES permit limitations which include BPT effluent limitations and BAT and BCT limits (based on Best Professional Judgment). This volume of drilling wastes (from the offshore subcategory) disposed onshore may be compared to EPA's 1987 estimates of 361 million barrels per year of drilling wastes generated from the drilling of wells in the "onshore" and "coastal" subcategories. (See "Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy," U.S. EPA, Office of Solid Waste, EPA/530-SW-88-003, December 1987.) A significant portion of these wastes from onshore drilling activities are disposed of onsite and not transported to commercial treatment and/or disposal facilities.

The drilling wastes generated offshore and transported to shore for treatment and/or disposal under this rule would be deposited in commercial land disposal facilities similar to those used to manage a portion of the drilling wastes generated by the onshore and coastal subcategories. These land disposal sites are generally located near the coast where the wastes are brought to shore. In evaluating the impacts from land disposal of the drilling wastes, EPA determined the availability of disposal capacity on a regional basis. For each regulatory option, EPA estimated the volume of wastes requiring land disposal and the excess, or unused, capacity of disposal facilities.

In the proposal, EPA had estimated available capacity for drilling fluids and drill cuttings by reviewing permitted capacity. At that time, data on the degree to which disposal capacity was used was not available. For the final rule, EPA updated capacity estimates and obtained data on the volumes of wastes treated at the disposal sites to derive more accurate projections of the "excess" available capacity. The "excess" available capacity is more useful for evaluating the non-water quality environmental impacts of the various options considered for the rule.

While drilling wastes are exempted from federal regulation as hazardous wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA) (Solid Waste Disposal Act [SWDA], 42 U.S.C. 6901-6992(k)), and no Subtitle D regulations specific to these wastes have been developed, there are existing State requirements for these wastes. No new federal requirements for the management of exploration and production wastes under RCRA Subtitle D have been proposed.

Gulf of Mexico Region

In developing the proposal, EPA surveyed state/local regulatory agencies and disposal facilities in late 1989 and early 1990 to estimate the available and projected annual disposal capacities of sites near the coast which could treat and dispose of drilling wastes. The results of this study are documented in "Onshore Disposal Of Offshore Drilling Waste: Capacity and Cost of Onshore Disposal Facilities," prepared for EPA by ERCE, March 1991. The evaluation reviewed the situation in the three major areas where onshore disposal of offshore drilling waste would be necessary: Gulf of Mexico, California, and Alaska. Treatment and disposal options for offshore waste disposal in each region were evaluated based on telephone contacts with knowledgeable individuals associated with regulatory agencies or disposal facilities. Estimates of regional capacity were derived from telephone contacts with facility operators, recently completed state hazardous waste Capacity Assurance Plans, State data on nonhazardous waste facilities, and literature sources.

In the Gulf Coast states, oil drilling wastes that are exempt from RCRA Subtitle C are generally accorded the regulatory status of nonhazardous wastes but are subject to state disposal requirements specific to oilfield wastes. Onshore oil drilling facilities are allowed to utilize drilling pits for storage of drilling fluids and drill cuttings. Upon closure and subject to state requirements, the drilling wastes can be either buried on-site, land spread, or injected into the underlying formation. Drilling wastes derived from onshore drilling operations are occasionally transported to an off-site, commercial disposal facility for ultimate disposal. Commercial disposal facilities in the region are permitted by the state to accept specific types of nonhazardous oilfield waste. These facilities are more commonly used by offshore and coastal drilling operations and by facilities located in wetlands areas or in inland waterways.

In the March 1991 study, disposal sites in the Gulf of Mexico region were classified in three categories. First, Tier 1 sites were those permitted to accept nonhazardous oilfield wastes which are currently accepting wastes from offshore. These are sites located in close proximity to drilling sites, generally are accessible by boat/barge, and charge competitive rates for disposal. Operations included in this category are landfarming, landfilling, and waste treatment prior to landfilling. The second category, Tier 2 sites, included facilities permitted to accept nonhazardous oilfield wastes but which were not accepting wastes from offshore at that time because of their relative lack of proximity to drill sites, their lack of marine unloading terminals or water access, their inability to compete with the rates charged by Tier 1 facilities, or the lack of sufficient demand for onshore disposal capacity. Finally, Tier 3 sites were those facilities permitted to accept hazardous waste and which could accept nonhazardous oilfield waste (at a much higher cost) should there be no other suitable disposal alternatives. The study projected the combined capacity of Tier 1 and Tier 2 sites at 30.7 million barrels of drilling wastes per year, with Tier 3 sites providing an additional 10.9 million barrels per year of capacity. It was noted that some portion of the permitted acreage in the Tier 1 category was not being used at the time of the survey; however, the capacity actually used was not quantified.

In developing options for the final rule, EPA improved upon the capacity estimates used for the proposal. EPA believes that in addition to the CWA's requirement to consider non-water quality environmental impacts, sound environmental policy requires that there be adequate onshore disposal capacity to dispose of drilling fluids and drill cuttings that will need to be barged to shore to comply with the zero discharge requirements, toxicity limits, and other requirements imposed by this rule. Thus, EPA must be careful in projecting how much landfill capacity is actually available for this use.

Accordingly, it is appropriate to determine how much of the permitted capacity is actually available for disposal of drilling fluids and drill cuttings generated offshore. Disposal capacity estimates made by EPA for the 1991 proposal did not account for impacts due to zero discharge limits for drilling fluids and drill cuttings limits proposed in a general permit covering coastal drilling activities in Texas and Louisiana (55 FR 23348; June 7, 1990). EPA expects to promulgate this general permit in early 1993. If promulgated as proposed, EPA anticipates that this permit will result in an incremental increase of 1.1 million barrels per year of coastal drilling waste requiring onshore disposal as a result of these new permit limitations. Although these wastes are originating in the coastal subcategory and thus are not affected by this rulemaking, the coastal drilling wastes do compete for the same onshore disposal capacity and therefore must be considered in determining disposal site availability.

EPA reviewed the analysis prepared for the 1990 and 1991 proposals to evaluate what facilities should be considered as available sites for disposal of drilling fluids and drill cuttings from offshore oil and gas platforms for purposes of determining non-water quality environmental impacts.

EPA has determined that it should not include hazardous waste facilities in its overall capacity estimates for this rule. Drilling wastes are exempted from federal regulation as hazardous wastes under subtitle C of RCRA. While exempted under subtitle C, there are existing state requirements for disposal of these wastes. In the Gulf coast states, commercial disposal facilities are permitted to accept specific types of nonhazardous oilfield waste. In EPA's judgment, adequate disposal capacity for hazardous waste disposal is an ongoing problem, and these hazardous waste facilities should be reserved for use to dispose of waste which cannot be disposed of in any other type of facility.

Because EPA wanted to make a realistic estimate of disposal capacity, EPA included in its estimates of available disposal capacity only those facilities that are currently accepting the type of drilling fluids and drill cuttings that would be generated offshore. Facilities excluded from EPA's onshore disposal capacity estimates include a permitted, but not yet constructed, site and a facility for which the operating permit is currently suspended. EPA also excluded a facility in northern Louisiana because disposal at this facility would require at least a five-hour truck ride, resulting in additional air emissions, energy use, and significantly higher disposal costs than the other sites which are located closer to shore.

Based on this analysis, total permitted capacity in the Gulf of Mexico region is estimated at 8.5 million bbl/year. A review of the wastes receipts from the disposal facilities indicated that approximately 3 million bbl of wastes were accepted for treatment and/or disposal at these facilities in 1989. Using the permitted capacity estimate of 8.5 million bbl/year, approximately 5.5 million bbl/year of onshore disposal capacity is available to accept additional drilling wastes (8.5 − 3.0=5.5 million bbl/year available capacity).

Under the regulatory option (Zero Discharge Gulf/California) requiring zero discharge of all drilling wastes for the Gulf of Mexico region, EPA projects an incremental increase of 6.6 million barrels per year of drilling fluids and drill cuttings from the offshore subcategory requiring onshore disposal at facilities on the Gulf coast. (Accounting for the coastal drilling wastes under the proposed coastal permit would increase the total by 1.1 MMbbl/yr to 7.7 MMbbl/yr.) Comparing the volume of offshore drilling wastes to current projections of 5.5 million barrels of available excess disposal capacity in the Gulf coast region, EPA concluded that the offshore wastes requiring onshore disposal under this option would exceed the available disposal capacity.

Additional regulatory options with requirements prohibiting discharges over lesser geographic areas (options setting discharge prohibitions at distances of 3, 4, 6, or 8 miles from shore) were evaluated with respect to the revised land capacity estimates. For the options prohibiting discharges of drilling wastes within 8 miles of shore, 1.4 million barrels per year of wastes from the offshore subcategory would be disposed of onshore in the Gulf region. The combination of offshore wastes (1.4 MMbbl/yr) and projected coastal wastes (1.1 MMbbl/yr) represents an estimated 45 percent of the projected available excess land disposal capacity in the Gulf coast region (2.5 MMbbl/yr equals 45% of 5.5 MMbbl/yr capacity). For the options prohibiting discharges of drilling wastes within 3 or 4 miles of shore, 685,000 bbl/yr or 793,000 bbl/yr, respectively, of drilling wastes from the offshore subcategory will require onshore disposal in the Gulf region. Including the 1.1 MMbbl/yr of projected coastal-generated drilling wastes, 33 to 35 percent, respectively, of the excess land disposal capacity in the Gulf coast region will be required under the 3 and 4 mile options. Additional discussion on the drilling waste volumes requiring onshore disposal and projections of available excess disposal capacity are further discussed in sections concerning BCT, BAT and NSPS options selection for drilling fluids and drill cuttings.

California Region

California laws and regulations provide for oil and gas wastes to be designated either hazardous or nonhazardous. Drilling wastes in California are considered nonhazardous provided the operator uses only approved additives and fluids. Although offshore drilling wastes requiring onshore disposal in California would be nonhazardous if the operator uses the approved additives and fluids in the drilling operations, disposal options appear limited. While in theory it may be possible to dispose of any oilfield waste in local Class III (nonhazardous waste that will not decompose) landfills, local regulatory agencies have indicated that they are not inclined to allow such disposal unless the waste is first stabilized for use as landfill cover. If not stabilized and disposed in a Class III landfill, the alternative disposal option for offshore drilling waste is disposal at a Class I hazardous waste site. In the 1991 study report, permitted Class III (stabilized, nonhazardous waste) disposal capacity was estimated at 3.4 million barrels per year and the Class I (hazardous waste landfills) disposal capacity at 6.5–10.5 million barrels per year. It was projected that the facilities available to perform the stabilization necessary to allow disposal at Class III landfills were operating at no more than one-half of the permitted capacity. As part of the final rulemaking, EPA reevaluated capacity estimates and now projects the onshore disposal capacity in the California region at approximately 19.3 million barrels per year (including 15.5 MMbbl/yr for Class III landfills).

Under the option requiring zero discharge of all drilling wastes for the California region, EPA projects that 233,000 barrels of offshore-generated drilling fluids and drill cuttings would require onshore disposal at facilities on the California coast. Comparing that to the projected disposal capacity in the California region, EPA concluded that the wastes requiring onshore disposal under this option would require less than two percent (2%) of the disposal capacity. The distances considered in other drilling fluids and drill cuttings options for this rule require less than one percent of the disposal capacity in the California region.

Alaska Region

The 1991 report identified no commercially operating disposal sites in Alaska accepting offshore drilling wastes. This lack of commercial disposal sites would require operators to transport the drilling wastes to another location such as Washington, Oregon, or California for disposal; apply to the State of Alaska for a permit to operate a commercial disposal facility for the offshore wastes; apply to the State to allow disposal of drilling wastes which have been either thermally treated or chemically stabilized (solidification) in currently-existing landfills; or inject the drilling wastes into underground formations. Injection of slurried drilling fluids and drill cuttings is currently practiced on a limited trial basis on the North Slope and has been considered for onshore use in other regions such as the Gulf of Mexico. However, the technology of injecting slurried drill cuttings is not sufficiently developed to apply to the offshore subcategory at this time.

Under all options considered by EPA for this rule, drilling wastes generated off Alaska would be excluded from the zero discharge limitation. (See the discussion of options considered.) Under the limitations imposed by this rule, EPA does anticipate a relatively small increase in the volume of offshore-generated drilling wastes requiring onshore disposal in this region. EPA considers the disposal options discussed above, in conjunction with privately-owned (industry-owned) onshore disposal sites, to provide ample capacity for disposal of these wastes. Onshore disposal capacity was a factor in excluding drilling wastes in this region from zero discharge; however, the difficulties involved in transporting large quantities of these wastes to shore (see section VII.A.2 of this notice), and the limited amount of storage space on-site at offshore drilling facilities (particularly mobile drilling units), also serve as a basis for the exclusion. Although the transportation and onshore disposal considerations precluded the zero discharge requirement for this region, these factors are not considered to prevent the industry from capturing and transporting the relatively small volumes of drilling wastes that are anticipated to require onshore disposal in this region. The volumes requiring onshore disposal under this rule would, for the most part, be relatively small, anticipated by the operator (and thus could be planned for accordingly), and typically occur toward the end of a drilling program when the potential for causing a halt to drilling would likely be minimized (since the waste volumes to be handled would either be small or onsite storage would be available). Such waste handling practices and operations would not be inconsistent with current practices under the current NPDES permit limitations.

b. *Energy Requirements.* Energy requirements for each of the treatment options considered in this rule were calculated by identifying those activities necessary to support onshore disposal of drilling wastes. Those activities requiring fuel consumption include supply boats to transport the drilling wastes, crane operation at the drilling sites and marine transfer stations to facilitate off-loading the wastes, trucks to transport the wastes from the marine transfer station to the onshore disposal site, and earth-moving equipment at the disposal site to facilitate landspreading and landfill operations. Since many disposal sites are either located at marine transfer stations, or wastes may be transferred at marine transfer stations from supply vessels to barges and then transported on waterways to the disposal sites, much of the drilling waste may not actually require truck transportation. However, the fuel requirements and air emissions attributed to truck usage in EPA's analysis are considered to approximate the energy requirements and air emissions resulting from the alternative use of barge traffic.

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 travelled by the boats, allowances for maneuvering, idling and loading operations at the drill site, and inport activities at the marine transfer station. EPA estimated fuel required to operate the cranes at the drill site and inport 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 travelled between the marine transfer station 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 methodology used to determine fuel consumption is further discussed in the Development Document. Table 8 summarizes the incremental increase in energy requirements for the drilling fluids and drill cuttings options considered for this rule.

c. *Air Emissions.* EPA estimated air emissions resulting from the operation of boats, cranes, trucks and earth-moving equipment by using emission factors relating the production of air pollutants to time of equipment operation and amount of fuel consumed. The incremental increase in air emissions associated with the control options considered by EPA in this final rulemaking are presented in Table 8.

In developing regulations to control air pollution from OCS sources pursuant to the 1990 Clean Air Act Amendments, the EPA Office of Air Quality Planning and Standards estimated the air emissions associated with various stages of oil/gas resource development activities ("Control Costs Associated With Air Emission Regulations For OCS Facilities," Final Report September 30, 1991. Prepared by Mathtech, Inc. for EPA). In this study, EPA estimated levels of both controlled and uncontrolled emissions from exploration, development, and production operations. Nitrogen oxides (NO_x) emissions from exploratory drilling activities were estimated at 78 tons/operation. For comparison, the increase in air emissions due to offshore and onshore activities related to onshore disposal of drilling wastes is estimated at approximately 1.5 tons of NO_x for each well subject to the zero discharge limitations.

d. *Interaction with OCS Air Regulations.* The regulation of air emissions from outer continental shelf (OCS) sources prior to the passage of the Clean Air Act Amendments of 1990 (CAAA) was the sole responsibility of the Minerals Management Service (MMS), which administered the Department of the Interior (DOI) air quality rules (30 CFR 270.45, 46). The CAAA partitioned the regulation of air emissions from OCS sources between MMS, which will continue to administer the DOI regulations for the Western and Central Gulf of Mexico planning areas (off the states of Texas, Louisiana, Mississippi and Alabama), and EPA, which will have responsibility for the regulation of OCS sources along the Pacific, Arctic and Atlantic coasts and along the Gulf coast off the state of Florida.

On September 4, 1992, EPA promulgated new requirements to control air pollution from OCS sources (57 FR 40792). The purpose of the requirements is to attain and maintain Federal and State ambient air quality standards, and to provide for equity between onshore facilities and OCS facilities located within 25 miles of state seaward boundaries (i.e., within 25 miles of the outer boundary of territorial seas). It should be noted that the effluent guidelines and NSPS promulgated today by this rule under the CWA apply to all activities located seaward of the inner boundary of the territorial seas and thus includes the territorial seas, the contiguous zone and the ocean.

The OCS rule establishes two separate regulatory regimes. For OCS sources within 25 miles of states' seaward boundaries, the requirements are the same as those that would be applicable if the source were located in the corresponding onshore area (COA). The National Ambient Air Quality Standard (NAAQS) attainment classification of the onshore area determines the degree of additional control and air emission offset requirements for OCS sources within 25 miles of a State seaward boundary (except in the Central and Western GOM planning areas). If any part of the onshore area adjacent to an OCS planning area is designated as nonattainment for a pollutant, then the regulatory requirements applicable to the nonattainment classification for that area would apply to the entire area of the OCS planning area within 25 miles of the State seaward boundary.

Sources located beyond 25 miles of the states' seaward boundaries are subject to federal requirements for Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and, to the extent that they are rationally related to the attainment and maintenance of federal or state ambient air quality standards or to PSD, National Emission Standards for Hazardous Air Pollutants (NESHAPS). All OCS sources operating adjacent to any State other than Texas, Louisiana, Mississippi, or Alabama will be subject to requirements under one of the above regimes.

In reevaluating the non-water quality environmental impacts associated with onshore disposal requirements for this rule, EPA considered the effect of the OCS air regulations and state requirements on the air emissions resulting from transporting drilling wastes. Areas requiring emissions offsets under the OCS air regulations (those adjacent to nonattainment areas) are located seaward of the outer boundary of the territorial seas (states' seaward boundary) to a distance of 25 miles from that boundary. Drilling activity within state waters would not come under the OCS air regulation, and those activities beyond the 25 mile delineation would not be subject to the limitations of a corresponding onshore area. Emissions in state waters would, however, be subject to state and local rules and may also require offsetting. In analyzing the impacts associated with this rule, EPA quantified potentially needed emission offsets and calculated their associated costs.

e. *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 final rule.

f. *Other Factors.* Impact of Marine Traffic on Coastal Waterways. In evaluating the impact of this rule on the potential for increased service vessel traffic, dredging, and the widening of navigation channels, EPA reviewed MMS data and industry comments regarding current practice in supply boat usage. The service vessel usage at offshore facilities may be as high as two supply boats per day and two crew boats per day during the exploration and development phases. In general, service vessels make three trips per week to exploration and development operations and one trip per week to production platforms. A boat may visit only one site or, if it is only going to production platforms, may visit as many as five platforms in a single trip.

The oil and gas industry in the Gulf of Mexico uses the extensive waterway system located within the Gulf coastal states to provide access between onshore support operations and offshore platforms and rigs. Oil industry support vessels moving along coastal navigation channels include crewboats, supply boats, barge systems, derrick vessels, geophysical-survey boats, and floating production platforms. Navigation channels serve as routes for service vessels traveling back and forth from service and supply bases. Generally, oil and gas industry use accounts for less than ten percent (10%) of all commercial usage of the Gulf coastal navigation channels according to MMS data.

The most recent data obtained from MMS show that about 25,000 service vessel trips are made annually to support oil and gas related activities in Federal waters of the Gulf of Mexico. The MMS data does not include vessel traffic destined for coastal or offshore activities in the State territorial seas and therefore undercounts actual boat traffic. (Note that, in the Gulf of Mexico, about 8 percent of existing platforms and 14 percent of projected new drilling activity in the offshore subcategory is within state territorial seas.) In estimating the vessel traffic resulting from this rule, EPA projected that transporting drilling wastes ashore from a well subject to zero discharge would require, on average, 5 to 6 service vessel trips and result in an incremental increase of approximately 740 service vessel trips per year. Ninety percent (90%), or 670, of these boat trips would take place in the Gulf of Mexico. Despite the limitations of the MMS data, it does indicate that the incremental increase in boat traffic due to this rule would be less than three percent (3%) of all service vessel traffic.

In evaluating impacts of vessel traffic for its Environmental Impact Statement for its five-year comprehensive program, MMS projected that an additional 100,000 service vessel trips will result from planned leasing and development activities. Although this boat activity will occur over the life of the new activities, the majority of the vessel traffic is expected to occur within the next 10–15 years. Upon analysis of current and projected vessel traffic and data on navigational channel usage, MMS concluded that some maintenance dredging or deepening of navigation channels may be required, but no new navigation channels were anticipated due to the increased traffic.

Since service vessels must have unimpeded access to supply bases to continue servicing offshore activities, maintenance dredging of navigation channels will be required regardless of whether this rule is promulgated. The channels used by vessel traffic in transporting drilling wastes to onshore disposal sites will also continue to be maintained since over 700,000 barrels of offshore-generated drilling wastes are already being transported to shore in compliance with NPDES permit limitations. Recalling that oil and gas related traffic accounts for less than ten percent of all commercial use of the navigation channels and that oil/gas related vessel traffic resulting from this rule will increase by less than three percent (3%), any increase in vessel traffic due to this rule would be small in relation to the total commercial boat traffic in these channels (3% of 10% equals 0.03%). No significant increase in dredging activities is anticipated as a result of this rule.

Safety

The industry has argued that injuries and fatalities would increase as a result of hauling additional volumes of drilling wastes to shore. 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 offshore oil and gas facilities.

Administrative/Enforcement Considerations

Administrative burden and enforcement issues associated with this rule were considered and are discussed in the following section on options selection.

5. BCT Option Selection

EPA has selected the "3 Mile Gulf/California" option for BCT effluent limitations for drilling fluids and drill cuttings. Drilling fluids and drill cuttings from wells drilled by existing sources at a distance of 3 miles or less from shore will be prohibited from discharge. Wells drilled by existing sources at a distance greater than 3 miles from shore would be allowed to discharge drilling fluids and drill cuttings after meeting the limitation for no discharge of free oil as determined by the static sheen test. However, for BCT in the Alaska region the BCT limitation for all wells is being set at no discharge of free oil as determined by the static sheen test. The exclusion from zero discharge only applies to drilling operations off Alaska; all other offshore regions, including those in which no drilling activity is currently taking place, must comply with the prohibition on discharges of drilling fluids and drill cuttings within 3 miles from shore.

As discussed above in section VII.A.2 under each option considered Alaska was excluded from the zero discharge requirement because specific situations exist in Alaskan waters (State and OCS waters off of Alaska) which make marine transport and onshore disposal of offshore-generated drilling wastes difficult. Reasons for this primarily relate to the severe weather conditions. Because of sea ice, tugs and barges can only be used for a short period of time in the summer during open water/broken ice season. In addition, winter snow and fog conditions restrict visibility. White-out conditions occur restricting air and water travel. EPA also considered the long distances (both offshore and onshore) required to transport the wastes to areas which may be suitable for land disposal, and the lack of current land disposal sites. For these reasons EPA is excluding wells drilled off Alaska from the zero discharge requirement. However, the discharges of drilling fluids and drill cuttings from all wells drilled in the offshore subcategory off of Alaska will be required to comply with the prohibition on discharges containing free oil.

The "3 Mile Gulf/California" option, when compared to the other options considered for the control of drilling fluids and drill cuttings, will result in progress toward the goal of the Clean Water Act to eliminate the discharge of all pollutants while providing the appropriate balance of the considerations required under the Act. As discussed in the above section on BCT costs, this option passes both BCT cost reasonableness tests and is economically achievable. EPA believes the non-water quality environmental impacts associated with the "3 Mile Gulf/California" BCT limitations, in conjunction with those additional impacts associated with the BAT and NSPS limitations on discharges of drilling fluids and drill cuttings and the impacts due to the coastal drilling general permit for Texas and Louisiana, are reasonable. The non-water quality environmental impacts are discussed in more detail in section VII.A.4 of this Notice and the Development Document.

EPA rejected a 4-mile zero discharge delineation due to the small difference in the number of new wells to be drilled between 3 and 4 miles, and comments identifying this mileage as causing some confusion and burden on permitting and inspection authorities and operators as well as a desire expressed by states and federal regulators to make the zero discharge zone consistent with the 3-mile delineation for state waters under the CWA. EPA has also rejected the "8 Mile Gulf/3 Mile California" and "Zero Discharge Gulf/California" options in large part due to non-water quality environmental impacts as discussed below. Since proposal, EPA has reevaluated the non-water quality environmental impacts and has determined that several factors have changed: the amount of waste to be disposed onshore under this rule, the amount of waste projected to be disposed onshore under the coastal drilling permit, and the disposal capacity for disposing of drilling fluids and drill cuttings. In reassessing the pollutant removals and non-water quality environmental impacts for this final rule, EPA revised downward the projections of energy requirements, air emissions, solid waste (drilling waste) requiring onshore disposal, and available "excess capacity" at permitted facilities available for disposal of drilling fluids and drill cuttings.

Prohibition on the discharge (zero discharge) of drilling fluids and drill cuttings as a treatment and control method (except for Alaska) was identified in the March 1991 proposal as technologically available and cost reasonable (passed BCT cost test). EPA rejected that option requiring zero discharge of all drilling wastes at the time of proposal because of concerns related to associated non-water quality environmental impacts. In this final rule, EPA rejects the "Zero Discharge Gulf/California" option because the incremental increase in drilling wastes (6.6 MMbbl/yr of drilling fluids and drill cuttings) requiring onshore disposal exceeds the onshore disposal capacity in the Gulf coast region and air emissions (54 tons/year) in the California region would be unacceptable.

As discussed above, under all options except "Zero Discharge Gulf/California," zero discharge off the coast of California was limited to a distance of three miles from shore. The Southern California air basin currently is in nonattainment of National Ambient Air Quality Standards (NAAQS) and the level of air emissions associated with some options considered for this rulemaking is significant. This region has undergone strict controls on air emissions for a number of years in an attempt to improve air quality. Although the absolute quantity of emissions anticipated off California due to compliance with today's rule are substantially less than those projected for the Gulf of Mexico, the California air basin is one in which impacts on air quality are of particular concern. Air quality in the Gulf region is generally much better than in California and, since controls on air emissions in the Gulf region are generally less stringent than in California, there are many options available in the Gulf region if needed to offset increased air emissions. In California, however, air quality controls have reached a point where it is much more difficult to obtain necessary offsetting reductions in air emissions. In evaluating the air emissions in this rulemaking, EPA determined that establishing a zero discharge limitation at 6 or 8 miles from shore, or for all wells off of California would result in an unacceptable level (42 to 54 tons/year) of air emissions. In setting the zero discharge requirement at a distance of 3 miles from shore, air emissions are significantly reduced to an acceptable level (3.3 tons/year). With regard to the drilling waste volumes for the California region, EPA identified no onshore disposal capacity problem and determined that sufficient disposal capacity exists for the volume of drilling waste anticipated under any regulatory option, including zero discharge from all wells. Energy requirements (440 bbl of diesel fuel per year) in this region were also determined to be acceptable under all regulatory options.

EPA rejects the "8 Mile Gulf/3 Mile California" option also because of unacceptable non-water quality environmental impacts. The amount of drilling fluids and drill cuttings that would be required to be disposed of onshore under this rule and the general permit for coastal drilling in the Gulf of Mexico would consume approximately 45 percent of the excess disposal capacity in the Gulf coast region. EPA believes that selecting this option does not leave an adequate capacity margin to dispose of wastes from current offshore activities in which drilling wastes fail the static sheen, toxicity or metals limits (or from the zero discharge zone) and future offshore, coastal, or onshore drilling activities not anticipated by EPA, or other reductions in capacity caused by cessation of operation (voluntarily or through revocation of existing permits) of currently permitted sites. EPA's selected option of setting the zero discharge requirement at a distance of 3 miles from shore reduces the onshore disposal volume to an acceptable level.

EPA received a number of comments recommending the establishment of the zero discharge zone at 3 miles from shore. At proposal, EPA considered the 3 mile distance in addition to the distances discussed above. However, EPA declined to choose that distance in its preferred option because industry profile information on existing platforms within 3 miles from shore was limited and projections for new well drilling activity within 3 miles needed additional confirmation. In the 1991 proposal, EPA solicited information regarding activity within State waters (3 miles), and stated that it would consider setting the final rule on distances other than 4 miles, including a 3-mile delineation, if additional information regarding activity in State waters became available. Subsequent to the proposal, EPA received additional data on the number and location of existing platforms which increased estimates of existing platforms and confirmed earlier estimates of projected activity within 3 miles of shore.

EPA also received comments regarding the potential for confusion and the administrative burden in selecting a delineation other than the pre-existing 3-mile boundary between State territorial seas and Federal waters. In all offshore areas with the exception of Texas and the Gulf coast of Florida, States assert jurisdiction over the mineral rights off their shores up to a distance of three miles. There is overlapping jurisdiction under the CWA and the Submerged Lands Act (SLA) (43 U.S.C. 1301, et seq.). Under the CWA, States have jurisdiction over waters extending three miles from shore. Persons discharging to these waters are required to comply with any state water quality standards. Under the SLA, Texas and Florida exercise mineral rights in the Gulf of Mexico up to 3 marine leagues (approximately 10.35 miles). In waters beyond 3 miles, or 3 marine leagues for Texas and Florida, the Minerals Management Service (MMS) of the Department of the Interior leases mineral rights and manages OCS mineral operations under the authority of the Outer Continental Shelf Lands Act (OCSLA). MMS conducts periodic inspections of offshore oil and gas activities in the Federal waters under the OCSLA and, under a Memorandum of Understanding (MOU) with EPA, conducts NPDES compliance inspections on behalf of EPA in those areas. Commenters asserted that it would be more appropriate to select the State/Federal water boundary as the delineation for a zero discharge limitation, rather than the 4-mile limit so that MMS or the Region would not have to inspect for zero discharge at any facilities within the one-mile band between 3 and 4 miles while inspecting for compliance with a different set of discharge limitations beyond 4 miles. EPA also believes that the three mile option, which is consistent with state waters under the CWA, will help to simplify the regulatory framework applicable to offshore waters. Another factor considered by EPA is that only about 12 wells per year (less than two percent of the total wells drilled annually) are expected to be drilled in the one-mile band between three and four miles from shore.

EPA agrees that these administrative and enforcement concerns are valid and has agreed to adopt the 3-mile option in the interest of simplifying the regulatory framework applicable to offshore oil and gas activities.

B. BAT and NSPS

1. BAT and NSPS Options Considered

Following a review of the comments and data received in response to the proposal, EPA modified the control and treatment options in developing the final rule. Three options were considered for BAT and NSPS control and treatment of drilling fluids and drill cuttings for the final rule. These options set BAT and NSPS limitations identical to BCT limits with respect to areas of zero discharge for drilling fluids and drill cuttings. BAT and NSPS limits differ from BCT in that they place additional limitations on the discharge of toxic and non-conventional pollutants for areas (greater distances from shore) in which discharges are permissible. NSPS is also limiting the discharge of conventional pollutants. These limitations are being placed on the drill cuttings as well as the drilling fluids because the data show that drilling fluid adheres to drill cuttings and is discharged along with the drill cuttings. The same pollutants found in drilling fluids are thus found on the drill cuttings.

The BAT and NSPS limitations on permissible discharges of drilling fluids and drill cuttings (e.g., those facilities not covered by the zero discharge limitations) consist of four basic requirements: (1) A toxicity limitation set at 30,000 ppm in the suspended particulate phase; (2) a prohibition on the discharge of diesel oil; (3) no discharge of free oil based on the static sheen test; and (4) limitations for cadmium and mercury set in the stock barite at 3 mg/kg and 1 mg/kg, respectively.

The 30,000 ppm toxicity limitation, prohibition on discharges of diesel oil and free oil, and the limitations on mercury and cadmium in the stock barite are required by general NPDES permits in Region 6 and 10 (Region 10's pre-approval method for toxicity is based on the 30,000 ppm limit). In Region 6, compliance with the no discharge of free oil limitation is allowed by either the visual or static sheen test. Permits in Regions 4 and 9 also include limits similar to the BAT and NSPS limits of this rule. To the extent that the limitations of this rule are already required by permits, EPA believes that this demonstrates that the limits are technologically available and economically achievable. The availability and economic achievability of the limitations included in this rule are further discussed in other sections of this preamble, the Development Document and the Economic Impact Analysis (EIA).

The 30,000 ppm toxicity limitation is technologically available and economically achievable and reflects the BAT and NSPS levels of control, as discussed in sections XIV and XVI of the preamble, the Development Document and the EIA. The limitation is the same as that proposed. The purpose of the toxicity limitation is to encourage the use of water-based or other low toxicity drilling fluids and the use of low-toxicity drilling fluid additives.

EPA believes that the 30,000 ppm toxicity limit on drilling fluids and drill cuttings is an appropriate BAT/NSPS limit based on product substitution and/or transporting drilling wastes to shore for disposal. For the rationale as to why EPA selected this limitation see section XVI. EPA has evaluated product substitution and barging/onshore disposal and finds these technologies to be available and economically achievable for this industry, resulting in no barrier to future entry. Product substitution refers to the substitution of lower toxicity drilling fluids and additives in place of higher toxicity fluids and additives. Product substitution as required in the Region 10 general permits for oil and gas facilities offshore Alaska and in the Region 6 general permit for oil and gas activities in the Gulf of Mexico has been upheld by two Federal Circuit Courts. See *API* v. *EPA*, 858 F.2d 261 (5th Cir. 1988) revised opinion, 864 F.2d 1156 (5th Cir. 1988) (Reg. 10 permit); *NRDC* v. *EPA*, 863 F.2d 1420 (9th Cir. 1988) (Reg. 6 permit). These standards are not expected to have any significant non-water quality environmental impacts mainly because the toxicity limits are already applied by existing permits and operators utilize product substitution wherever possible to prevent the need for onshore disposal. Where the toxicity of the spent drilling fluids and cuttings exceeds the toxicity limitation, the method of compliance with this limitation would be to transport the spent fluid system to shore for either reconditioning/reuse or land disposal. Further discussion on the implementation of the toxicity limitation is presented in section XX.

The prohibitions on the discharge of free oil and diesel oil are intended to limit the oil content in drilling fluids and drill cuttings wastestreams and thereby control the priority as well as conventional and nonconventional pollutants present in those oils. The pollutants free oil and diesel oil are each considered to be "indicators" of the toxic and nonconventional pollutants in the complex hydrocarbon mixtures present in those oils. An indicator pollutant is one that, by its regulation, will provide control on discharges of one or more toxic pollutants. Diesel oil is being regulated as a nonconventional pollutant and an indicator because it contains such toxic organic pollutants as benzene, toluene, ethylbenzene, naphthalene and phenanthrene. Free oil is being regulated as a nonconventional pollutant and an indicator of the toxic and nonconventional pollutants found present in crude and other oils, and (under NSPS) as a surrogate for oil and grease in recognition of its previous use under BPT. The sampling and analysis data demonstrate that when the amount of oil is reduced in drilling fluids, the concentrations of priority and nonconventional pollutants present in the fluid (and that portion of drilling fluid which adheres to drill cuttings) are reduced. EPA has determined that the controls on diesel oil and free oil will provide BAT and NSPS-level control of the toxic and nonconventional pollutants present in drilling fluids and drill cuttings. This method of toxic regulation is necessary because it is not feasible to establish specific limitations upon each of the toxic pollutants present in the drilling fluids and drill cuttings.

In the March 1991 proposal, EPA proposed a prohibition on the discharge of drilling fluids and drill cuttings containing diesel oil in detectable amounts. Comments received in response to the March 1991 proposal questioned the need to consider detectability and expressed concern regarding the potential for confusion over the term "in detectable amounts." EPA agrees that inclusion of the term "in detectable amounts" was superfluous. Since the proposed prohibition was an absolute prohibition on any diesel (whether as a mud system component or an additive for any purpose), any drilling fluid system to which an operator had added diesel oil would be automatically prohibited from discharge, regardless of its concentration and whether or not it was above the analytical level of detection. In addition, any drill cuttings associated with that diesel-contaminated drilling fluid system would also be prohibited from discharge. The term "in detectable amounts" has been deleted in this final rule since the discharge of all drilling fluids and drill cuttings containing diesel oil is prohibited.

The discharge of diesel oil, either as a component in an oil-based drilling fluid or as an additive to a water-based drilling fluid, would be prohibited under the BAT and NSPS limitations of this rule. The method of compliance with this prohibition is to: (1) Use mineral oil instead of diesel oil for lubricating and spotting purposes; or (2) transport to shore for recovery of the oil, reconditioning of the drilling fluid for reuse, and land disposal of the drill cuttings. EPA believes that in most cases substitution of mineral oil will be the method of compliance with the diesel oil discharge prohibition. Mineral oil is a less toxic alternative to diesel oil and is available to serve the same operational requirements.

The diesel oil prohibition is technologically available because an operator may substitute the diesel with mineral oil and water-based drilling fluids. Whenever this is not possible, the operator can transport the drilling fluids and drill cuttings to shore for treatment and/or disposal. The diesel oil prohibition is not expected to have any significant non-water quality environmental impacts and is economically achievable as shown in section XIV of the preamble and the EIA. Existing NPDES permits prohibit the discharge of oil-based drilling fluids as well as diesel added to a drilling fluid for lubricating purposes or a pill to free a stuck drill pipe.

The prohibition on discharges of free oil as determined by the static sheen test is technologically available and economically achievable and reflects the BAT and NSPS levels of control. The static sheen test requires the operator to collect a measured sample volume, mix it with a volume of receiving water in a container, and observe for the presence of a sheen. This pre-discharge test is preferable to the post-discharge visual sheen test because it prevents discharges of fluids containing free oil, rather than merely observing (after the discharge) for any noncompliance with the requirement. Further, the static sheen test is performed under carefully controlled conditions (such as lighting and viewing aspect) and can be performed at any time, while the visual sheen test (and thus discharges relying upon the visual sheen test) can only be conducted under conditions in which the operator can see the surface of the water and observe for the presence of a sheen. The existing BPT limitation prohibits discharges of free oil for drilling fluids and drill cuttings. Existing permits in Region 9 and 10 require operators to use the static sheen test to determine compliance with the no discharge of free oil limit. In Region 6, compliance may be determined by either the static sheen or visual sheen test. This limitation is not expected to result in any significant non-water quality environmental impacts under this rule.

Mercury, cadmium and other metals present in discharges of drilling fluids and drill cuttings are often also found present as impurities in the barite used as a weighting agent in drilling fluid systems. In this rule, EPA is limiting mercury and cadmium in the stock barite as indicator pollutants to control the metals content of the drilling fluids and drill cuttings discharges. Compliance with this limitation is based on product substitution of barite from sources that either do not contain these metals or contain the metals at levels below the limitation.

A number of studies have found that the level of metals impurities in barite is a function of the barite source. Barite deposits occur primarily as either vein or bedded deposits. The concentrations of trace metals, including cadmium, mercury, iron, lead, zinc, mercury, arsenic, tin, titanium, and chromium vary considerably in mined deposits. The bedded, or "clean barite," deposits are relatively pure deposits with trace metals typically at very low levels. Vein, or "dirty barite," deposits are quite impure and contain elevated levels (10–100 times above those of clean barite) of the metals. EPA has evaluated data to determine whether limiting the levels of cadmium and mercury in stock barite would also limit the concentrations of other metals as well. The results of EPA's analysis showed that for cadmium in barite, the metals with positive correlations (the metals were reduced when cadmium was reduced) include arsenic, sodium, tin, titanium and zinc. For mercury in barite, the metals with positive correlations include chromium, lead, molybdenum, sodium, tin, vanadium and zinc. Based on this data, EPA believes limiting cadmium and mercury in stock barite as indicator pollutants will also limit other related metals in discharges of drilling fluids and drill cuttings. This method of regulation is necessary because it is not feasible to establish specific limitations for each of the toxic pollutants present in this wastestream. Based on data in the API/USEPA Metals Data Base, the availability and metals content of clean barite sources, the barite volumes required to support offshore drilling operations, and existing NPDES permit requirements, EPA has determined that the BAT and NSPS limitations should be set at 1 mg/kg for mercury and 3 mg/kg for cadmium, on a dry weight basis as measured in the stock barite.

In the 1985 proposal, EPA included proposed limitations of 1 mg/kg each (maximum) of cadmium and mercury in the discharge of the whole drilling fluid on a dry weight basis (essentially an end-of-pipe limitation). In the 1988 notice and 1991 proposal, EPA presented several additional alternative limitations on mercury and cadmium for drilling fluids and drill cuttings. One of these alternative limitations presented by EPA in the 1991 proposal was a limitation of 3 mg/kg of cadmium and 1 mg/kg of mercury based on stock barite composition. In its preferred option presented in the March 1991 proposal, EPA proposed setting the limitation on cadmium and mercury at 1 mg/kg each in the whole drilling fluid.

Subsequent to the March 1991 proposal, EPA received comments and information regarding the potential for the presence of cadmium in the formation itself to cause noncompliance with limitations applied at the point of discharge. In these comments, many industry representatives recommended establishing limits in the final rule on cadmium and mercury in the stock barite at 3 mg/kg and 1 mg/kg, respectively. EPA has analyzed data from the American Petroleum Institute's Fifteen Rig Study. In this study, samples of drill cuttings, used drilling fluid, and barite from a number of drilling sites were sampled for metals content. Results of EPA's statistical analysis indicate that some cadmium present in the drilling fluids came from a source other than the barite. Therefore, product substitution could not ensure compliance with the end-of-pipe limitation in the whole drilling fluid proposed in March 1991. In this final rule, EPA has rejected control alternatives establishing limitations on cadmium and mercury at the point of discharge and is instead setting the limitations in the stock barite.

The limitations on cadmium and mercury in stock barite are technologically available and economically achievable and reflect the BAT and NSPS levels of control. EPA has investigated the adequacy of available foreign and domestic supplies of barite to meet the final mercury and cadmium limits of the rule. This investigation compared foreign and domestic supplies, with compositions adequate to meet the final limits, to the projected industrial demand. The conclusion was that there are sufficient supplies of barite capable of meeting the limits of this rule to meet the needs of offshore drilling operations. As part of its investigation, EPA also considered the potential for the increased demand for clean barite stocks resulting from this rule to cause a rise in the cost of barite. The estimated increase in barite costs was included in EPA's economic impact analysis for the rule and found to be economically achievable. (See the Development Document, EIA and rulemaking record for a detailed discussion of the availability and economic achievability of the cadmium and mercury limitations.) Existing general NPDES permits in Regions 6 and 10 limit cadmium and mercury in the stock barite at 3 mg/kg and 1 mg/kg, respectively. Existing permits in Region 9 also limit cadmium and mercury in the stock barite. Since most existing permits already limit cadmium and mercury in the stock barite, and compliance with the limit is assured prior to the start of drilling operations by obtaining clean barite sources, no significant non-water quality environmental impacts associated with the cadmium and mercury limits are anticipated.

2. Non-Water Quality Environmental Impacts and Other Factors

The non-water quality environmental impacts associated with the BAT and NSPS limitations of this rule are the same as discussed for BCT in section VII.A.4.

3. BAT and NSPS Option Selection

EPA has selected the "3 Mile Gulf/California" option, and rejected the other BAT and NSPS options considered, for the final effluent limitations (BAT) and new source performance standards (NSPS). This option is technologically available and economically achievable and reflects the BAT and NSPS levels of control. Also, EPA considered non-water quality environmental impacts in selecting the final BAT and NSPS options. These considerations are summarized in section VIII.A describing the BCT option selection. This selected option will prohibit the discharge of drilling fluids and drill cuttings from new and existing sources at a distance of three miles or less from shore. New and existing sources at a distance greater than three miles from shore would be permitted to discharge drilling fluids and drill cuttings after meeting the following requirements: (1) A toxicity limitation set at 30,000 ppm in the suspended particulate phase; (2) a prohibition on the discharge of diesel oil; (3) a prohibition on the discharge of free oil as determined by the static sheen test; and (4) limitations of 3 mg/kg for cadmium and 1 mg/kg for mercury in the stock barite. However, for the Alaska region, discharges of drilling fluids and drill cuttings from existing sources will be excluded from the zero discharge limitation. As previously discussed for BCT, discharges in this region are excluded from zero discharge because of the special climate and safety conditions that exist for parts of the year that make marine transportation of drilling wastes particularly difficult and hazardous, the lack of current onshore disposal sites, and the long distances (offshore and onshore) over which the transportation of these wastes would have to occur. Instead, all wells drilled offshore of Alaska will be required to comply with the limitations on free oil, diesel oil, toxicity, and metals content in barite.

VIII. Basis for the Final Regulation—Produced Water

A. BCT

1. BCT Options Considered

EPA evaluated reinjection of produced water into underground formations, granular filtration, membrane filtration, and gas flotation as options for the technology basis for the limitations established in final rule.

EPA rejected membrane filtration as a technology basis for the rule because it has not been sufficiently demonstrated as available to support national effluent limitations at this time. In the proposal, EPA selected membrane filtration as the preferred technology basis for BAT and NSPS produced water limitations. Membrane filtration is a commercially demonstrated technology in other industries and several manufacturers have been developing this technology for treatment of produced water. Although not yet available to the offshore oil and gas industry, operators have shown interest in membranes and some offshore testing of full-scale systems has begun. In the 1991 proposal, EPA relied upon pilot scale test data in proposing oil and grease limitations. In April 1991, EPA conducted a field study of a membrane filtration unit installed on an offshore platform to obtain additional full-scale data and performance information. Information collected by EPA during the field study and comments submitted by the industry in response to the proposal indicate that the membrane system tested at full-scale still suffers from periodic operational problems (e.g., clogging, actual treatment capacity less than design capacity). EPA continues to believe that further development of membrane systems (either that system already undergoing full scale testing, or other membrane systems under development) should enable full-scale systems capable of long-term, effective treatment of produced water. However, data currently available does not support selection of this technology as a basis for this rule.

Although technologically and economically achievable, granular filtration was rejected as the technology basis for this final rule. EPA's evaluation of granular filtration performance data indicates that, while this technology does provide some removals of priority and nonconventional pollutants, the pollutant removal efficiency of granular filtration is generally not as effective as that attainable through improved operation of gas flotation technology. In addition, the capital and annual operation and maintenance costs associated with granular filtration are significantly higher than the costs of gas flotation systems.

The four options selected for final consideration in developing BCT limitations for produced water discharges were based either on reinjection or gas flotation technologies.

BPT All Structures: EPA included as an option setting BCT equal to BPT. By doing so, EPA realized that the removals of conventional pollutants due to compliance with stricter standards may not be cost reasonable under the BCT cost tests.

Flotation All: All discharges of produced water, regardless of the water depth or distance from shore at which they are located, would be required to meet limitations on oil and grease content at 29 mg/l monthly average and a daily maximum of 42 mg/l. The technology basis for these limits is improved operating performance of gas flotation.

Zero Discharge 3 Miles Gulf and Alaska: Wells located at a distance of 3 miles or less from shore would be prohibited from discharging produced water. Facilities located more than 3 miles from shore would be required to meet oil and grease limitations of 29 mg/l monthly average and 42 mg/l daily maximum based on the improved operating performance of gas flotation technology. Because of the unacceptable level of air emissions associated with reinjection off California, all wells off California would be excluded from the zero discharge requirement. Currently existing single-well dischargers in the Gulf of Mexico would also be excluded from the discharge prohibition because the economic impacts of a zero discharge limit on these projects would result in immediate shutdown and cause significant production impacts. As considered for this rulemaking, single-well dischargers are defined as single-well facilities which operate their own, and do not share, produced water treatment systems. Discharges of produced water from these excluded facilities would be required to comply with the oil and grease limitations based on improved operating performance of gas flotation technology.

Zero Discharge Gulf and Alaska: This option would prohibit all discharges of produced water based on reinjection of the produced water. All facilities off California and all currently existing single-well dischargers in the Gulf of Mexico would be excluded from zero discharge requirement. They would, however, be required to comply with the oil and grease limitations developed based on improved operating performance of gas flotation technology.

In referring to the options considered for control of produced water discharges, the Gulf of Mexico, California and Alaska regions are used in the option descriptions and accompanying discussion. Use of these regions in this way is only a "shorthand" way of referring to regulatory options and does not exclude other geographic areas from coverage under this rule. For the BCT, BAT and NSPS limitations under this rule, all offshore areas other than offshore California and Alaska would be required to comply with the limitations established for the Gulf of Mexico.

2. BCT Options Selection

The options considered for BCT regulation were evaluated according to the BCT cost reasonableness tests. The pollutant parameters used in this analysis were total suspended solids (TSS) and oil and grease. All options, except the "BPT All Structures" option, fail the BCT cost reasonableness test. The range of results for the POTW test (first part of the BCT cost reasonableness test) test is $10.02 to $32.53 per pound of conventional pollutant removed. A value less than $0.46 per pound is required to pass the POTW test. Thus, EPA is establishing the BCT limitation in this final rule equal to BPT (48 mg/l monthly average; 72 mg/l daily maximum) for produced water. There are no non-water quality environmental impacts associated with this BCT limitation. The BCT cost reasonableness tests for the produced water options are discussed in more detail in the Development Document.

B. BAT and NSPS

1. BAT and NSPS Options Considered

The BAT limitations considered for produced water are similar to those previously discussed for BCT. The only difference is that while BCT options are intended to control the conventional pollutants, BAT options focus on the control of toxic and nonconventional pollutants. Oil and grease remains the only regulated pollutant in produced water. Oil and grease is being limited under BAT as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants. Oil and grease is being limited under NSPS as both a conventional pollutant and as an indicator pollutant controlling the discharge of toxic pollutants.

The options considered for NSPS are similar to those considered for BAT, with the only exception being that the exclusion for single-well dischargers from the zero discharge limitation is not applicable under NSPS. The single-well exclusion for BAT was developed because the costs associated with requiring existing single-well dischargers to retrofit filtration and reinjection equipment are sufficiently high that a zero discharge limitation is not economically achievable and immediate shutdown of these facilities will result in unacceptable production impacts, as discussed further in section VIII.B.3, below. Since new sources are able to allow for adequate space in designing new facilities and compliance costs are less for the new sources, economic and production impacts on these facilities will be less than the impacts on existing sources.

2. Non-Water Quality Environmental Impacts

In assessing non-water quality environmental impacts for produced water, EPA projected energy requirements and air emissions associated with the regulatory options considered. The following is a description of the non-water quality environmental impacts and a summary of the results of the evaluations identifying the estimated levels and impacts for each option.

a. *Energy Requirements and Air Emissions.* Energy requirements and resulting air emissions for the control options considered by EPA are presented in Table 9. Estimates are presented incremental to current BPT limitations and thus represent the expected increase above current emissions levels and energy consumption. On September 4, 1992, EPA promulgated new regulations establishing requirements to control air pollution from outer continental shelf (OCS) sources (57 FR 40792). These new requirements on air emissions apply to all OCS sources located offshore of the states along the Pacific, Arctic, and Atlantic coasts and along the Gulf coast off the state of Florida. Those OCS sources located in the Gulf of Mexico west of 87.5 degrees longitude (i.e., off the coasts of Texas, Louisiana, Mississippi and Alabama), where the majority of offshore oil and gas activities are located, are not covered by the new rules. Sources of air pollution from offshore activities include leaks, oil-water separators, dissolved air flotation units, painting apparatus, and storage tanks, but more significantly diesel or gas engines for generating electrical power or driving reinjection pumps.

Energy consumption for the different options was determined based on the produced water flowrates and the associated power requirements of the treatment systems. For the zero discharge limitation requiring reinjection of produced water, energy consumption was based on gas-driven pumps operating at injection pressures of 1,800 psi. Gas-driven pumps are generally preferred by operators for use on offshore platforms because the structures typically have gas production on-site which can serve as the fuel source. When using electric-driven injection pumps, fuel must be consumed to generate electricity, then converted back to mechanical energy to pump the produced water underground. The extra energy conversion step needed for electrical reinjection pumps increases fuel requirements because of the reduced process efficiency. Electrical power is the energy source for gas flotation units. The energy consumption associated with gas flotation systems was derived based on power requirements and the fuel necessary to produce that level of electrical power.

Air emissions calculated for produced water treatment options include nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2) and hydrocarbons (HC). Air emissions were determined by applying emission factors which estimate air emissions associated with the consumption of fuel. The methodologies used to estimate fuel consumption and calculate air emissions are described in more detail in the Development Document.

As illustrated in Table 9, the option requiring zero discharge of all produced water greatly increases air emissions and fuel requirements as compared to the flotation all option. This is due primarily to the energy required to operate the injection pumps.

TABLE 9.—NON-WATER QUALITY ENVIRONMENTAL IMPACTS PRODUCED WATER

Option	Fuel requirements (thousand BOE/yr)		Total emissions (tons/yr)	
	BAT	NSPS	BAT	NSPS
Flotation All	157	29	169	31
Zero Discharge 3 Miles Gulf & Alaska	165	152	185	164
Zero Discharge Gulf & Alaska	977	785	1,041	849

BOE: Barrel of oil equivalent.

3. BAT and NSPS Options Selection

EPA has selected the "Flotation All" option for the final BAT and NSPS limitations for produced water. This option requires all existing and new sources to meet discharge limitations on oil and grease content (29 mg/l monthly average; 42 mg/l daily maximum) based on improved performance of gas flotation technology. EPA has determined this option to be available and economically achievable and reflects the BAT and NSPS levels of control. Oil and grease is being regulated under BAT as an indicator pollutant for toxic and nonconventional pollutants. Under NSPS, oil and grease is being regulated both as a conventional pollutant and as an indicator for toxic and nonconventional pollutants.

Gas flotation is a technology which has been used for many years in the treatment of produced water at offshore oil and gas platforms and served as the technology basis for BPT effluent limitations. Currently, approximately 35 percent of offshore platforms use gas flotation in their produced water treatment systems. At proposal, EPA considered establishing limitations based on improved operation and maintenance of gas flotation technology. At that time, EPA identified problems associated with the performance evaluation that served as the basis for limitations considered at proposal. Subsequent to the proposal, EPA received a number of comments from industry claiming that the gas flotation technology was indeed capable of serving as the basis for BAT and NSPS limitations and submitted data as support. These comments and data support EPA's contention in the proposal that improved performance was achievable for gas flotation treatment systems and the data submitted corrected earlier limitations of the performance evaluation. The development of the produced water limitations is discussed in more detail in section V.B.1 of the preamble, the Development Document and record for the rule.

EPA rejected the most stringent option, zero discharge based on reinjection. Although reinjection technology is feasible in some circumstances, some facilities cannot reinject produced water because of geologic conditions in specific locations. Also, the air emissions (1,041 tons/year for BAT; 849 tons/year for NSPS) and energy requirements (977,000 BOE/year for BAT; 785,000 BOE/year for NSPS) associated with this option at offshore facilities, especially in light of the air emissions and energy requirements associated with potential future requirements for facilities in the coastal subcategory (see e.g., proposed produced water permit proposing zero discharge of produced water based on reinjection at coastal facilities in Louisiana and Texas, 57 FR 60926 (December 22, 1992)), are unacceptably high. EPA also considered that a zero discharge requirement based on reinjection under BAT would result in capital costs of $3 billion, with a peak annualized cost of $737 million (year 1; 1991 dollars). Zero discharge based on reinjection under NSPS would result in capital costs of $2.6 billion, with a peak annualized cost of $391 million (year 15; 1991 dollars). In light of the statutory mandate to consider cost in setting BAT and NSPS, and the possibility that the industry might be required to bear the costs of reinjection in the coastal subcategory, EPA considered the very high aggregate cost on a nationwide basis in reinjecting the reinjection option. Also, reinjection for all production structures (both new and existing sources) is projected to result in a 1.0 percent loss in production (121 million barrels of oil equivalent (BOE)) over the 15-year period analyzed for this rule. This production loss, especially in light of the production loss that may occur as a result of potential future requirements for facilities in the coastal subcategory, are unacceptably high. This loss of production is not merely a cost concern. Loss of production has independent significance in light of the statutory directive that EPA consider energy impacts in establishing effluent limitations guidelines and new source performance standards under the Clean Water Act.

Finally, although reinjection is the only technology identified that would control naturally occurring radioactive materials (NORM) that may be present in produced water at offshore facilities, EPA believes that it would be premature to require zero discharge based on reinjection at this time. EPA has examined the existing information concerning the presence of radionuclides in the effluent of offshore oil and gas facilities. The results of this analysis are summarized in two support documents entitled "Prevalence of Radium in the Gulf of Mexico," (EPA January 15, 1993) and "Summary of Produced Water Radioactivity Studies," (EPA January 1993).

As is discussed in more detail in these documents, the data concerning the presence of radionuclides in the offshore subcategory are limited and exist only for a small number of platforms throughout the offshore subcategory. Most of the data that exist are from facilities in the coastal subcategory; of the offshore data that exist, most sampling took place at facilities within three miles of the coast of Louisiana. In addition, the data that do exist show wide variability in the concentration of radionuclides in produced water. The limited data that exist are not from studies designed to determine the distribution of radionuclides from oil and gas facilities across the offshore subcategory. In addition, EPA used the very limited data it has (data from a total of six platforms out of 2,549 platforms across the entire subcategory, which EPA does not believe are necessarily representative of produced water discharges across the entire Gulf of Mexico or the entire offshore subcategory) to make a preliminary estimate of risk to human health from produced water effluent in the offshore subcategory. As discussed further in the support document referenced above, in addition to EPA's uncertainty about whether the few platforms from which data were collected are representative of the entire subcategory, there are several additional difficulties inherent in these preliminary risk estimates.

EPA recognizes that it does not carry a high burden of demonstrating environmental harm from pollutants or of demonstrating environmental benefits of its technology-based effluent limitations guidelines and NSPS. EPA also does not have an obligation to sample each facility within a subcategory to identify pollutants to be regulated. At the same time, however, the CWA gives EPA discretion to determine when it has sufficient information to make a decision to regulate a pollutant.

In the case of this particular rule, EPA has determined that it does not have sufficient information concerning the presence of radionuclides in produced water effluent across the entire subcategory to regulate radionuclides at this time. EPA believes that this is a close case, but given the limited amount of information EPA has characterizing the presence of radium in entire offshore subcategory, EPA is exercising its discretion not to control radium in this rule. While EPA believes that regulating radionuclides that may be present in produced water is premature, EPA intends to obtain more information about the presence of radionuclides in the offshore subcategory by requiring radium monitoring requirements in NPDES permits for this subcategory. EPA has promulgated such requirements in its most recent permit issued for the OCS in the Western Gulf of Mexico. (57 FR 54642; November 19, 1992).

EPA also rejected the Zero Discharge 3 Mile Gulf and Alaska option because EPA has determined that gas flotation is the appropriate technology basis for BAT and NSPS established by this rule. EPA has no basis in terms of the factors considered in making this determination and in rejecting zero discharge to require zero discharge for only a small segment of the facilities within the offshore subcategory.

IX. Basis for the Final Regulation—Produced Sand

A. BCT, BAT and NSPS Options Considered

EPA considered two options for this waste stream: (1) Establish the requirement equal to the current NPDES permit limitations prohibiting discharges of free oil; or (2) prohibit discharge of produced sand, technologically based on transporting to shore for treatment and/or disposal. The technology basis for the option limiting free oil content is a water or solvent wash of produced sands prior to discharge. The method of determining compliance with the free oil prohibition would be the static sheen test. The prohibition on the discharge of free oil (as an indicator of toxic and nonconventional pollutants) or the zero discharge requirement for produced sand would reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters.

B. Option Selection

EPA has selected the zero discharge option for BCT, BAT and NSPS control of produced sand. The technology basis for this limitation is transportation to shore for treatment and/or disposal. EPA has determined that zero discharge reflects the BCT, BAT and NSPS levels of control because, as it is widely practiced throughout the industry, it is both economically and technologically achievable. The total cost of zero discharge under the rule is estimated at $4 million (1991 dollars) for the entire offshore subcategory.

EPA does not consider the prohibition on the discharge of free oil indicative of a "best available" or "best demonstrated" technology. As discussed in section VI.C., onshore disposal is widely practiced throughout the industry as a means to comply with current NPDES permit limitations on free oil discharge. Onshore disposal is usually selected by operators because of economics (costs of on-site washing are comparable to costs of onshore disposal), logistic considerations (scheduling or space), or because the sand fails NPDES permit limitations even after washing. Data submitted from an industry-sponsored study demonstrates the variability of oil content in washed produced sand. The oil content of washed produced sand in the study ranged from 0.66 to 4.2 percent by weight. With the exception of a small percentage of the sand which is removed periodically from piping low points and tank blowdowns, produced sand discharges are infrequent bulk discharges occurring during scheduled shutdowns of the produced water treatment system. Sand washing systems are generally contracted from service companies as needed, although some operators permanently install sand washing systems on selected platforms to serve as a central facility to receive and clean wastes from other sites. Data submitted by the industry regarding sand washing performance demonstrates that even in the case of a washing system which provides for removal of the free oil, residual liquids and solids (by-products from washing) remain which are unable to meet the no free oil limitation and they must be disposed of in a manner other than ocean discharge (typically by onshore treatment and disposal).

In the March 1991 proposal, EPA suggested the possibility of requiring zero discharge only for those facilities within 4 miles from shore if information showed that the volumes associated with a zero discharge limit for all produced sand were excessive. EPA reevaluated projections of produced sand generation and onshore disposal capacity in developing this final rule, and has confirmed that zero discharge of all produced sand is achievable and the appropriate limitation for BCT, BAT and NSPS. Therefore, EPA is rejecting the 4-mile option for produced sand.

EPA did not perform a BCT cost test on the no discharge of free oil option, because no, or minimal, incremental costs would be incurred. NPDES permits currently limit discharges of produced sand containing free oil, with compliance determined by visual sheen test.

The basis for the compliance costs assigned to the zero discharge option is presented in section V.C. Although BPT limitations for produced sand have never been promulgated, existing NPDES permits prohibit the discharge of free oil in the produced sand wastestream. For the purpose of conducting the BCT cost reasonableness test for the rule, the BPT level of control is considered to be equal to the no free oil limitation of the existing permits. Thus, BPT costs and pollutant removals are determined as the costs/removals associated with the onshore disposal of 34 percent of produced sand generated, and the costs/removals associated with washing/discharge for 66 percent of the produced sand generated annually. The costs and pollutant removals due to upgrading from BPT to the candidate zero discharge BCT limitation are determined by the costs/removals associated with onshore disposal of the produced sand currently discharged at sea (66 percent of the produced sand generated annually).

EPA encountered difficulties in estimating the cost of BPT for produced sand. EPA was unable to obtain firm estimates of sand washing costs from industry operators. EPA did receive sand washing cost estimates of $125 per barrel of produced sand from an equipment vendor. Since the estimate of sand washing is substantially higher than EPA and industry estimates of the cost for onshore disposal of produced sand, EPA does not consider the $125 per barrel quote to be representative of the industry-wide cost of BPT. Also, the sand washing estimate provided by the vendor was for a prototype sand washing system under development and was estimated as the cost for a demonstration washing project.

The cost for sand washing can be difficult to estimate, even for the operators. The cost per unit volume of sand can vary significantly as a function of the sand volume washed, difficulties encountered in washing, and the success (or lack of success) in washing the sand. As discussed in section V.C., produced sand wastes are infrequently discharged (typically removed from vessels once every three to five years) and can vary widely in volume (usually less than 100 barrels per vessel cleanout, although downhole problems can infrequently result in substantially greater volume). Depending on the volume of sand generated, scheduling constraints, and other economic and logistical considerations, operators choose between: (1) Sand washing and discharge on-site; (2) transporting the sand to another platform where the sand from several platforms may be washed and discharged; or (3) onshore disposal. If sand washing is selected by the operator, it is usually contracted out to offshore service companies. The goal of the sand washing is to reduce the oil content of the produced sand to the extent that the discharge complies with the no free oil limitation. There is, however, no guarantee that sand washing will be successful. If after washing the produced sand is still unable to comply with the no free oil limit, onshore disposal is usually necessary (and therefore incurring both washing and onshore disposal costs). Also, according to data submitted by the industry, the sand washing evolution produces wastes (washing liquids and a portion of the solids) which are unable to meet the no free oil limit. These wastes are typically disposed of onshore.

For the purpose of conducting the BCT cost reasonableness test, and based on the information discussed above and the frequency at which produced sand is currently disposed of onshore as an alternative to sand washing, EPA estimated the cost of sand washing to be comparable to the cost of onshore disposal. The average industry-wide BPT cost of sand washing is estimated at $10 per barrel of produced sand. Considering that day rates for offshore service vessels are approximately $3,000 per day and that produced sand volumes are typically less than 100 barrels each, it would be difficult for operators to achieve significantly lower sand washing costs even if the produced sand from several platforms are combined. Using a higher per barrel sand washing cost for BPT (as would be suggested by the equipment vendor estimate discussed above) provides a lower value in the BCT industry cost test and would make the BCT zero discharge limitation more cost reasonable.

Based on the volumes of produced sand washed offshore and the volumes disposed of onshore under current limitations, EPA estimates a BPT cost of $2.4 million (1986 dollars) and conventional pollutant removals of 68.8 million pounds, resulting in an overall BPT cost per pound of $0.036 per pound (1986 dollars).

The zero discharge limitation, in relation to the existing no free oil limit on produced sand, is projected to remove an additional 129.2 million pounds of conventional pollutants at an incremental cost of $2.3 million (1986 dollars). The BCT costs and pollutant removals result in a POTW test result of $0.018 per pound (1986 dollars). Since the POTW test result is less than $0.46 per pound (1986 dollars), the result passes the POTW test.

For the industry cost effectiveness test, the result of the POTW test is divided by the BPT cost per pound, and results in a value of 0.51. Since the result is less than 1.29, the result passes the industry cost-effectiveness test. Since the zero discharge limitation passes both tests, it is found to be cost reasonable.

Based on existing data, EPA is unaware of any unacceptable non-water quality environmental impacts associated with this produced sand limitation. Cleanout of produced water treatment systems typically produces less than 100 barrels of produced sand. The cleanouts occur during a platform shutdown and typical cleanout cycle is once every three to five years. The volume of produced sand collected from vessel blowdowns is small enough that operators are able to use the supply boats that service offshore platforms on a frequent and regular basis, rather than contract for dedicated vessels to transport the waste to shore. The produced sand collected during tank and vessel cleanouts are typically small volumes that can be transported to shore using either the regularly scheduled supply boats or the work boats chartered to support the sand removal or other general maintenance during the platform shutdown.

EPA is aware of current efforts by industry to develop technologies that would wash produced sand more efficiently than washers currently in use and achieve additional pollutant removals. In light of this ongoing effort, MMS and DOE have raised the concern that the imposition of a zero discharge requirement on produced sand will prevent the development of improved sand washing technologies. Also, as part of the ongoing environmental assessment for offshore new source permits to implement these offshore guidelines, additional information is being gathered on the characteristics of produced sand, including NORM levels in that waste stream.

MMS and DOE have indicated that it will provide EPA with additional information on these issues. EPA welcomes information from all interested parties on the feasibility and pollutant removal efficiency of new produced sand washing technologies, the fate of solvents from produced sand washing (i.e., treatment, recycle or disposal), the characteristics of produced sand, the availability of disposal sites, and appropriate site specifications and requirements for disposal of produced sand that contains NORM, including possible disposal alternatives such as down-hole disposal in abandoned wells. EPA will consider revising the zero discharge requirement for produced sand, if appropriate, after evaluating this information. If a technology-based limit contained in an NPDES permit is based on the zero discharge requirement for produced sand in this guideline, and the guideline is subsequently revised to permit discharge with limitations based on new sand washing technologies, the anti-backsliding provision of the CWA, section 402(o), would not preclude revision of the zero discharge permit limit consistent with the revised guideline (see (40 CFR 122.44 (1)(1) and 122.62)).

X. Basis for the Final Regulation—Deck Drainage

A. Options Considered

BPT limitations for deck drainage prohibit the discharge of "free oil." Typical BPT technology for compliance with this limitation is a "skim pile" which facilitates gravity separation of any floating oil prior to discharge of the deck drainage. The options considered by EPA for this rule were: (1) Prohibit the discharge of free oil; or (2) set the limitation for deck drainage equal to the limitation established for produced water under this rule, technologically based on commingling and treating deck drainage with produced water.

B. Option Selection

EPA has selected the option requiring no discharge of free oil for BCT, BAT and NSPS control of deck drainage; EPA has determined that these limitations and standards properly reflect BCT, BAT and NSPS levels of control. EPA did not identify any other available technology for this waste stream. Because of the difficulties in obtaining a representative sample of this waste stream for conducting the static sheen test since the effluent is located in an inaccessible location, compliance with this limitation is determined by the visual sheen test. Deck drainage is typically collected in a sump tank where initial oil/water separation takes place. Water discharged from the sump tank is usually directed to a skim pile, where additional oil/water separation occurs. The separation process in the skim pile typically occurs beneath the ocean surface, and the separated water is discharged to the ocean from the bottom of the skim pile. (The skim pile is essentially a bottomless pipe with internal baffles to collect the separated oil.) The difficulties in obtaining a representative sample of skim pile effluent preclude the use of the static sheen test for this wastestream. (The operation of a skim pile is discussed in more detail in the Development Document.)

In the proposal, EPA presented as its preferred option establishing effluent limitations for deck drainage based on commingling the deck drainage with the produced water. As such, limits based on filtration within 4 miles from shore, and oil and grease limits equal to current produced water BPT were selected as preferred in that proposal. Upon review of information received by the Agency since proposal, EPA determined that because of adverse effects on the produced water treatment system, basing the limitations on commingling deck drainage with produced water is not technologically available. Commingling deck drainage with produced water was rejected because: (1) The resulting flow variations could result in frequent upsets of the produced water treatment system; (2) oxygen-enriched deck drainage water, when combined with the high salt content of produced water could result in increased corrosion; (3) oxygen present in deck drainage may combine with iron and sulfide in produced water causing solids formation and fouling treatment equipment; and (4) detergents used in deck washdown cause emulsification of oil and may degrade the produced water treatment process.

EPA considered and rejected the option of establishing limitations on deck drainage based on an add-on system specifically designed to treat only deck drainage. An add-on treatment specifically designed to capture and treat deck drainage, other than the type of sump/skim pile systems typically used, on offshore platforms is not technologically feasible. Deck drainage discharges are not continuous discharges and they vary significantly in volume. At times of platform washdowns, the discharges are of relatively low volume and are anticipated. During rainfall events, very large volumes of deck drainage may be discharged in a very short period of time. A wastewater treatment system installed to treat only deck drainage would have to have a large treatment capacity, be idle at most times, and have rapid startup capability. Since startup periods are typically the least efficient for treatment systems and offshore platforms have limited available space for storage of the volumes of deck drainage which occur, EPA determined that an add-on treatment system appropriate for the treatment of deck drainage was not available.

Since BCT, BAT and NSPS are being set equal to the current BPT, there are no costs or non-water quality environmental impacts associated with this limitation and it is available and economically achievable. The BCT limitation of no discharge of free oil is also considered to be cost reasonable under the BCT cost test. Since the POTW test result and the industry cost-effectiveness test results are both zero (and therefore pass their respective tests), the limitation is cost reasonable. This determination that zero BCT cost results in passing the cost reasonableness test is consistent with the BCT methodology which became effective August 22, 1986 (51 FR 24974; July 9, 1986).

XI. Basis for the Final Regulation—Well Treatment, Completion, and Workover Fluids

A. BCT

EPA is establishing BCT prohibiting discharges of free oil under BCT for this rule. Compliance with this limitation would be determined by the static sheen test. Based on the available data regarding the levels of conventional pollutants present in well treatment, completion and workover fluids, EPA did not identify any options which would pass the BCT cost test other than establishing the limitation equal to the current BPT prohibition on discharges of free oil. Using the pollutant loadings data presented for these fluids in the Development Document and the estimated compliance costs and pollutant removals for the option establishing oil and grease effluent limits on these fluids, the results fail the BCT cost reasonableness test. There are no costs or non-water quality environmental impacts associated with this BCT limitation and, since it is equal to BPT, it is available and economically achievable. The BCT limitation is also considered to be cost reasonable under the BCT cost test. Since the POTW test result and the industry cost-effectiveness test results are both zero (and therefore pass their respective tests), the limitation is cost reasonable.

B. BAT and NSPS

1. BAT and NSPS Options Considered

Well treatment, completion, and workover fluids may either stay in the hole, resurface as a concentrated volume (slug), or surface from the well dispersed with the produced water. Two options were considered for BAT and NSPS control for this waste stream: (1) Prohibit the discharge of free oil; or (2) meet the same limitations on oil and grease content as established under this rule for produced water.

In the options considered for BAT and NSPS, free oil or oil and grease are being limited as an indicator pollutant for the control of toxic and nonconventional pollutants. Oil and grease would also be limited under NSPS as a conventional pollutant. Compliance with the free oil prohibition would be determined by the static sheen test.

2. BAT and NSPS Option Selection

EPA is establishing BAT effluent limitations and new source performance standards (NSPS) for well treatment, completion, and workover fluids equal to the BAT and NSPS requirements for oil and grease content in produced water. EPA has determined that these limitations and standards properly reflect BAT and NSPS levels of control for well treatment, completion and workover fluids. The technology basis for this limitation is commingling and treating the treatment, completion and workover fluids with the produced water wastestream. This limitation requires all existing and new sources to meet the discharge limitations on oil and grease content of 29 mg/l monthly average; 42 mg/l daily maximum. Although it is a conventional pollutant, oil and grease is being regulated under BAT as an indicator for toxic and nonconventional pollutants. Under NSPS, oil and grease is being regulated both as a conventional pollutant and as an indicator for toxic and nonconventional pollutants. Those facilities unable to commingle without causing a treatment system upset could comply by transporting the fluids to shore for recycle and reuse, where appropriate, or disposal.

EPA has determined that BAT and NSPS oil and grease limitations based on commingling well treatment, completion and workover fluids with produced water are available and economically achievable based on information regarding industry operating practices, comments submitted by industry representatives, and an industry report on the treatment of these fluids (Hudgins, C.M., "Chemical Treatments and Usage in Offshore Oil and Gas Production Systems," October 1989.). Well treatment, completion and workover fluids often surface commingled with produced water, rather than as a discrete volume (or slug). At times operators are unable to predict when the fluids will surface or even distinguish when the return has occurred. At such times, the treatment, completion and workover fluids are commingled in the produced water treatment system even though there is no existing requirement to do so.

Some comments on the proposed rule submitted by industry representatives stated that the final rule should require treatment, completion and workover fluids to be treated the same as produced water based on commingling. Also, an industry-prepared report submitted by API (Hudgins, 1989) states that, except for platforms with very low produced water flowrates, the produced water treatment systems are capable of treating well treatment, completion and workover fluids without upset to the produced water treatment system. For those facilities considered by EPA to potentially be unable to commingle these fluids without causing a treatment system upset, EPA based compliance with the BAT and NSPS limitations on transporting these fluids to shore for recycle and reuse, where appropriate, or disposal.

The option prohibiting discharges of free oil under BAT and NSPS would achieve no incremental removal of pollutants from this wastestream over and above the existing BPT requirements, and ignores an economically and technologically available treatment alternative. Therefore, EPA rejected the no discharge of free oil limitation for BAT and NSPS.

In its preferred option for the March 1991 proposal, EPA presented effluent limitations for well treatment, completion, and workover fluids based on requiring zero discharge of any concentrated fluids slug along with a buffer volume preceding and following the fluids slug. Fluids which did not resurface as a distinct slug were proposed to comply with produced water limitations. EPA has since determined that a limitation which requires capturing a buffer volume on either side of a fluids slug is not technologically achievable because it is not always possible and may not be entirely effective. In commenting on the proposal, the industry characterized completion and workover fluid discharges as small volume discharges which occur several times during the workover or completion operations which can last between seven and thirty days. Based on this information, EPA no longer considers the discrete slug and buffer to be a proper characterization of the way workover, completion or treatment fluids resurface from the well. Since the fluids often resurface slowly and over a period of time, and are often commingled with the produced water, EPA considers treatment of these fluids commingled with produced water in the produced water treatment system to be the appropriate technology.

EPA estimates peak BAT (first year) compliance costs of $1.7 million (1991 dollars) and peak NSPS (year 15) compliance costs of $1.0 million. For those treatment, completion and workover fluids which are commingled and treated with the produced water, non-water quality environmental impacts will be negligible based on comparison of the fluid volumes with produced water volumes. For those fluids expected to be transported to shore for disposal, some non-water quality environmental impacts will occur. The anticipated non-water quality environmental impacts associated with the BAT and NSPS limits are considered acceptable. The volumes of treatment, completion and workover fluids to be handled are small (250–300 barrels per event) and the regularly scheduled supply boats have adequate space to transport the containers of spent fluids. Offshore platforms would have adequate space for storage of the spent fluids for the periods when the supply boats are not scheduled for the platform or when offloading to the supply boats is infeasible due to weather conditions. Onshore treatment and disposal of spent fluids by injection into underground formations at centralized treatment facilities will result in a small increase in energy requirements and air emissions. The total volume of treatment, completion and workover fluids generated (and thus that portion requiring onshore disposal) is a function of the number of producing wells and drilling activity. EPA projects that the volume of these fluids disposed of onshore as a result of this rule will be greatest immediately after promulgation (141,000 bbl/yr) and decrease to approximately 50,000 bbl/yr fifteen years after promulgation. Fuel requirements and air emissions were estimated based on two reinjection scenarios: (1) Two 235–HP diesel pumps with average injection pressure of 1,000 psig; and (2) one 165–HP diesel pump with average injection pressure of 260 psig. Under the high pressure scenario, the peak year required 2,800 gallons of diesel fuel and emitted 2.8 tons of air pollutants, decreasing to 1,000 gallons of diesel fuel and 1.0 ton of air emissions in year 15. For the low pressure scenario, 700 gallons of diesel fuel were required and 1 ton of air pollutants emitted in the first year after promulgation, decreasing to 250 gallons of diesel fuel and 0.4 tons of air emissions in year 15.

XII. Basis for the Final Regulation—Domestic Wastes

Under BCT and NSPS, EPA is prohibiting the discharge of all floating solids and incorporating requirements limiting discharges of garbage as included in U.S. Coast Guard regulations at 33 CFR part 151. These Coast Guard regulations implement Annex V of the Convention to Prevent Pollution from Ships (MARPOL) and the Act to Prevent Pollution from Ships, 33, U.S.C. 1901 *et seq.* Discharges of foam are also prohibited under BAT and NSPS. (The definition of "garbage" is included in 33 CFR 151.05.)

The limitations established are all technologically available and economically achievable and reflect the BCT, BAT and NSPS levels of control. Under the Coast Guard regulations, discharges of garbage, including plastics, from fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with one exception. Victual waste (not including plastics) may be discharged from fixed or floating platforms located beyond 12 nautical miles from nearest land, if such waste is passed through a comminuter or grinder meeting the requirements of 33 CFR 151.75. Section 151.75 requires that the grinders or comminuters must be capable of processing garbage so that it passes through a screen with openings no greater than 25 millimeters (approximately one inch) in diameter. A permit promulgated by Region 6 for the Western Gulf of Mexico OCS incorporates the Coast Guard regulations (57 FR 54642; November 19, 1992). Discharge of foam in other than trace amounts is included in this Region 6 permit and the 1986 general permit for the Gulf of Mexico OCS as a mechanism for controlling detergents (51 FR 24922).

Since these BCT, BAT and NSPS limitations for domestic waste are already in either existing NPDES permits or Coast Guard regulations, these limitations will not result in any additional compliance cost, or additional non-water quality environmental impacts. There are no incremental costs associated with the BCT limitations; therefore, it is considered to pass the two part BCT cost reasonableness test.

XIII. Basis for the Final Regulation—Sanitary Wastes

BCT and NSPS limitations for sanitary wastes in this rule are equal to the current BPT limitations. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons must contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Offshore facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons must comply with a prohibition on the discharge of floating solids.

At proposal, EPA discussed the availability of alternative treatment and control options. No alternative technologies available for installation at the offshore facilities were identified. EPA did consider the appropriateness of requiring operators to capture sanitary wastes and transport the wastes to shore for treatment. Specific data were not available regarding the costs of transporting sanitary wastes to shore for treatment. EPA projected compliance costs based on the costs of transporting drilling wastes to shore (excluding the fee charged by onshore drilling waste disposal facilities). These projected compliance costs, in conjunction with pollutant removal estimates, did not pass the BCT cost-reasonableness tests and therefore EPA decided not to base limits on onshore disposal. EPA rejected zero discharge of sanitary wastes under NSPS because such a limitation would in reality result in operators transporting the wastes to shore for treatment and subsequent discharge by publicly owned treatment works (POTW) back into surface waters. Also, the zero discharge limitation would incur additional non-water quality environmental impacts (from the vessel traffic) and compliance costs.

Since there are no increased control requirements beyond those already required by BPT effluent guidelines, there are no incremental compliance costs or non-water quality environmental impacts associated with BCT and NSPS limitations for sanitary wastes. Since these limitations are equal to BPT, they are available and economically achievable. In addition, the BCT limitation is also considered to be cost reasonable under the BCT cost test. Since the POTW test result and the industry cost-effectiveness test results are both zero (and therefore pass their respective tests), the limitation is cost reasonable.

EPA is not establishing BAT effluent limitations for the sanitary waste stream because no toxic or nonconventional pollutants of concern have been identified in these wastes.

XIV. Economic Analysis

A. Introduction

EPA's economic impact assessment is presented in the "Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry" (hereinafter, "EIA"). This report details the investment and annualized costs for the industry as a whole and the impacts of these costs on affected projects, typical companies involved in offshore oil and gas drilling and production operations, and future oil and gas production from the offshore region. The report also estimates the economic effect of compliance costs on Federal and State revenues, balance of trade considerations, and inflation.

EPA has also conducted an analysis of the cost-effectiveness of alternative treatment options. The results of the cost-effectiveness analysis are expressed in terms of the incremental costs per pound-equivalent removed. Pound-equivalents account for the differences in toxicity among the pollutants removed. Total pound-equivalents are derived by multiplying the number of pounds of a pollutant removed by a toxic weighting factor. The toxic weighting factor is derived 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. Cost-effectiveness is calculated as the ratio of incremental annualized costs of an option to the incremental pound-equivalents removed by that option. This analysis, "Cost-Effectiveness Analysis of Effluent Limitation Guidelines and Standards of Performance for the Offshore Oil and Gas Industry" (hereinafter "CE report"), is included in the record of this rulemaking. Since the discharges are to a marine environment, salt-water toxic weighting factors were used wherever they were available.

B. Economic Methodology

EPA developed 34 economic model platforms to represent the diversity in offshore platform size (i.e., number of well slots per platform), geographic location (Gulf of Mexico, Pacific, and Alaska), and production type (oil only, gas only, or both). Distinct technical and economic characteristics were developed for each model. Costs included in the models are those associated with exploration, development, and production, as well as the costs needed to meet current regional permit requirements. Costs and revenues were estimated over the life of the project based on current requirements to establish baseline financial summary statistics, such as economic lifetime, production, corporate cost per BOE, net present value, and internal rate of return. Each of these parameters varies by model project.

Then, capital and annual O&M costs associated with various options were added to the baseline costs. The model recalculates the economic lifetime of the project, annualizes the regulatory costs over the new project lifetime, and recalculates production and financial summary statistics. Project impacts were evaluated by determining the change from the baseline values caused by the increased regulatory costs, rather than on the baseline values themselves. Costs were summed over all projects to provide total capital, annual, and annualized costs of the regulation.

EPA developed two representative company financial profiles—one for major integrated companies and one for independent oil companies—to assess the impact on oil and gas companies operating in the offshore area. Pre- and post-regulation balance sheets were developed for the typical companies. The impacts of the regulatory costs on the financial health of the companies were investigated by the change in financial ratios caused by those costs.

Production losses include those reductions in hydrocarbon extraction resulting from immediate closure of existing projects, new projects that are not undertaken, and curtailed lifetimes. These were based on the change in production and net present values for the projects induced by the regulatory costs. That is, if a project became unprofitable with the additional costs, it was assumed to close or not be undertaken.

EPA also analyzed secondary impacts of the regulation. These include: Revenue loss to the federal government due to tax shields on expenditures, revenue loss to federal and state governments through potentially lower bonus bids for new offshore projects, changes in the balance of trade, inflation, and impacts on related service industries.

C. Summary of Costs and Economic Impacts

1. Basis of the Analysis

The economic analysis has four major components: (1) An estimate of existing and projected structures that incur costs under this rule; (2) use of an economic model to evaluate per-project impacts and annualize capital costs and operating and maintenance costs; (3) an aggregate of the annualized costs to estimate the total costs for the regulation; and (4) an evaluation of the impacts of those costs on typical projects, typical companies, future oil and gas production, Federal and State revenues, balance of trade, and other secondary effects.

In response to comments received on the 1991 proposal, changes were made to the economic analysis. These changes include:

- The inclusion of existing structures currently in production in State waters of the offshore subcategory in the Gulf of Mexico (affects BAT profile).
- A re-evaluation of the profile of existing structures off California (affects BAT profile).
- Considering only the $21/bbl oil price, constrained development scenario (affects NSPS profile).
- Consideration of additional boundaries at 3-miles (for all effluents) and 8-miles (for drilling fluids and drill cuttings, only), in addition to the 4-mile boundary presented in the March 1991 proposal.
- Inclusion of compliance costs for waste streams previously believed to incur negligible costs, e.g., treatment, workover, and completion fluids; and produced sand. (The selected options for deck drainage, domestic wastes, and sanitary wastes are still assumed to create no additional costs and thus incur no impacts.)

The base year for the economic analysis is 1986. This was set for the 1988 Notice of Data Availability, when it was the most recent year for which a complete set of cost, revenue, and future production data were available. In other words, a consistent set of data were used to develop the economic models representing typical projects in that profile. This "snapshot" in time was maintained for several reasons. First, the economic impact analysis examines the change from the baseline values caused by the incremental costs of pollution control, rather than focusing on the baseline values themselves. Second, 1986 represents a recent nadir for the oil industry in terms of oil prices, revenues, and financial health. Third, not changing the baseline values of the economic models allows a clearer understanding of the changes caused by recosting, different boundaries, and other factors listed above. Fourth, EPA evaluated the changes to the profiles of new drilling activity and production structures when the 15-year period of the analysis was shifted into the future (1991–2005 and 1993–2007) and found that the results varied minimally (within 3 percent) around the original profile (see sections III.B.2 and V.F.); and therefore the 1986 projection remains valid for the 15 year period following promulgation. Costs are presented here in 1991 dollars. Where cost components have increased in time, the Engineering News Record Construction Cost Index is used to inflate 1986 dollars to 1991 dollars (see EIA for details).

The industry profile used in this analysis is presented in section V.F. EPA estimates 2,549 existing structures will incur compliance costs under the BAT regulations of this rule. It is estimated that a total of 759 new development and production structures will be installed during the 15-year period following promulgation. The costs for these new structures are assigned as NSPS compliance costs.

The number of wells drilled can vary widely from year to year. EPA estimated the total number of wells drilled during a 15-year period after the regulation goes into effect and then divided that total by 15 to obtain an average annual number of wells drilled. The average annual number of wells drilled is 759 wells per year. (It is coincidental that the average number of new wells drilled annually is equal to the total number of new development and production structures to be installed over the next 15 years.) About one-third of new wells are projected to be classified as existing sources because they are exploratory in nature or will be drilled from existing structures. Since the difference in drilling waste compliance costs for new and existing sources is negligible (because they comply with the same requirements), the incremental costs for drilling waste options do not depend on whether they are BAT wells or NSPS wells.

2. Total Costs and Impacts of the Regulations

The total costs and impacts of the regulations combine the BAT and NSPS costs for all waste streams. BAT costs are highest in the first year following promulgation when, for the purposes of the analysis, all existing sources incur costs to upgrade their pollution control systems. These annualized costs will diminish in time as these projects come to the end of their economic life. NSPS costs, on the other hand, are small in year 1 but are assumed to grow annually until they peak in the 15th year following promulgation at which time the rate of new source facilities ceasing production will equal, or exceed, the rate of new sources coming into production. Adding the two sets of peak costs would overstate the impacts since the peaks occur 15 years apart. EPA therefore looked at the impacts in year 1 and year 15. The cost components are summarized in Table 10. The combined annualized cost for the selected options is $134 million in year 1 and $38 million in year 15 (1991 dollars).

TABLE 10.—COMBINED COST OF FINAL RULE

[1991 dollars, thousands]

Waste stream	Control option	Annualized cost in year one	Annualized cost in year fifteen
Drilling fluids & drill cuttings	3 mile Gulf/CA	18,954	18,954
BAT produced water	Flotation all	108,400	0
NSPS produced water	Flotation all	907	13,605
BAT treatment & workover fluids	Oil & grease limitations	1,693	0
NSPS treatment & workover fluids	Oil & grease limitations	0	842
NSPS completion fluids	Oil & grease limitations	210	210
Produced sand	Zero discharge	4,127	4,127
Total combined cost (before taxes)[a]		134,291	37,738

[a] Net cost to industry will be lowered by tax savings realized. These tax reductions have been included in estimates of federal revenue losses.

Note: No incremental compliance costs are incurred for deck drainage, domestic wastes and sanitary wastes.

EPA examined the combined effect of regulatory options on BAT and NSPS projects. The BAT models begin at the projects' economic midlife, a time at which most drilling programs have been completed. For an existing single-well structure in the Gulf of Mexico with its own production equipment (Gulf-1b) which is assumed to add-on a flotation system, the combined effects of the selected options for produced water, treatment and workover fluids, and produced sand is expected to reduce the net present value by 40 percent and increase the corporate cost per barrel-of-oil-equivalent (BOE) by 28 percent. (This model project, termed Gulf-1b, is considered indicative of offshore projects most sensitive economically because its source of revenue is a single producing well. Most offshore platforms produce hydrocarbons from multiple wells.) For a Gulf of Mexico project comprising 12 well slots and 10 producing wells, the same requirements lead to a four percent decline in net present value and an increase of three percent for the corporate cost per BOE. (This model, termed Gulf-12, is considered representative of a typical offshore platform.) There were no production losses beyond those already seen with the produced water option.

In evaluating the economic impacts of the rule on new projects, EPA included the costs of increased pollution control requirements for drilling fluids, drill cuttings, completion fluids, produced water, treatment and workover fluids, and produced sand. Although exploratory wells are always defined as existing sources under the rule, the drilling fluids and drill cuttings compliance costs associated with exploratory wells are incorporated into the NSPS models. Since the economic impact models are designed to estimate impacts and viability on a per-project basis, including in the NSPS model the exploratory efforts (wells) conducted to identify and quantify producible oil and gas deposits is appropriate and allows EPA to fully consider the effects on financial ratios.

For a Gulf-1b project, the combined costs lead to a 2 to 5 percent increase in the corporate cost of production, depending on whether new equipment is needed. If new equipment is needed, the net present value becomes negative. These projects are assumed to be canceled and production is lost. If new equipment is not needed, the net present value for the project remains positive, but with a 65 percent decline in value from the baseline. For a more typical Gulf-12 project, the same requirements lead to decrease in net present value of 5 to 6 percent, and an increased corporate cost of 1 to 1.5 percent per BOE.

In the real world, there will be projects that fall between the BAT and NSPS models, e.g., platforms that are installed prior to promulgation but complete part of their drilling program after this rule is issued. These platforms are much closer to the beginning of their economic life than to their midpoint but not all wells on the platform will have been drilled under the new BAT requirements. For these platforms, the per-project impacts are estimated to be equal to or less than the BAT per-project impacts, depending upon the number of wells drilled under the new requirements.

The year 1 costs are estimated to reduce the working capital of a typical major oil company by 0.5 percent. (Working capital is the financial ratio most sensitive to increased costs.) For year 15, the working capital decreases by 0.1 percent. For a typical independent oil company working offshore, the year 1 costs would reduce working capital by nearly 5 percent. The year 15 costs would reduce the working capital by about 1.4 percent.

Potential production losses are measured over the entire 15-year time period of the analysis. Production losses result from shortened economic lifetimes, immediate shut-down of existing projects, and cancellation of new projects. Impacts associated with the final rule would result in the potential loss of 0.1 percent of the energy expected to be produced by the Offshore subcategory over the 15-year period (cumulative total of approximately 15.3 million BOE).

The selected options potentially could result in a $129 million (year 1) to $38 million (year 15) loss to federal revenues through tax effects and lower lease bids (1991 dollars). Losses to state revenues due to a potential lowering of lease bids ranges from $8 million (year 1) to $2 million (year 15; 1991 dollars). The impact of this potential loss in state revenue is minimal when compared to total state revenue representing, for example, less than 0.04 percent of total state revenues in Texas. Furthermore, these are potential losses. Companies may not choose to recoup all the cost increase through lower lease bids because if the bids are too low, companies might not win the lease. Therefore, companies may absorb the entire compliance cost of the regulation through reductions in profits. In other words, the impact on federal and state revenue would depend upon the action the companies may take through the lease bids—absorb the costs by not lowering the lease bids or pass on these costs through lower lease bids. The actual impact on revenues would probably be somewhere in this estimated range but is hard to predict at this time.

The final rule is not expected to affect energy prices, inflation, employment, or international trade. The selected options may, in fact, lead to positive impacts in the offshore service industry due to increased use of the service vessel fleet, onshore treatment/disposal requirements, and the need to retrofit or upgrade some existing treatment systems. EPA finds the costs of the final BAT and NSPS regulations to be economically achievable for the oil and gas industry.

D. Drilling Fluids and Drill Cuttings

BAT limitations and associated compliance costs for drilling fluids and drill cuttings are the same for BAT and NSPS wells. Because there is no difference between BAT and NSPS requirements for drilling wastes, EPA's analysis shows that the economic impact of the BAT limitations for drilling fluids and drill cuttings is the same as the impact of the NSPS limitations discussed below. For these reasons, the costs, cost-effectiveness, and economic achievability for BAT and NSPS drilling fluids and drill cuttings limitations are presented on a combined basis. The projections of future activity estimate that, on the average, 759 exploratory, delineation, and development wells will be drilled annually for the 15-year period of the analysis.

No capital costs are associated with the options for drilling fluids and drill cuttings because oil companies that drill offshore typically do not purchase vessels for transporting the wastes, but instead contract that service. The annualized cost of limits on drilling fluids and drill cuttings in this final rule is $19 million, of which about one-third or $6 million is estimated to be the BAT portion of the costs (1991 dollars). For new and existing oil and gas Gulf-12 model platforms, the net present value decreases by 0.6 percent while the corporate cost per BOE increases 0.1 percent. For the model single-well structure with its own production equipment (Gulf-1b), the drilling waste limitation decreases the net present value by 7 percent while the corporate cost of production increases by 0.2 percent. None of the options considered in this rulemaking for drilling fluids and drill cuttings has an adverse impact on hydrocarbon production.

The BAT and NSPS limitations of the final rule are projected to reduce the working capital of a typical major company by 0.1 percent and the working capital of a typical independent company by 0.7 percent. According to EPA's analysis, the rule would have no effect on oil and gas prices, employment, or international trade. EPA finds the costs of the selected option for BAT and NSPS control of drilling fluids and drill cuttings to be economically achievable.

BCT limitations for drilling fluids and drill cuttings within 3 miles from shore are equal to BAT and NSPS limits. Beyond 3 miles from shore, only the prohibition on discharges of free oil applies to BCT. Thus, compliance costs for BCT do not include the cost of substituting clean barite for dirty barite, monitoring costs for toxicity or diesel oil, or onshore disposal costs for drilling wastes failing the toxicity and diesel limitations.

On a per-well basis, the transportation and onshore disposal costs for BCT is equal to the BAT and NSPS costs. As discussed above, BAT and NSPS costs for drilling fluids and drill cuttings are economically achievable. Consequently, the BCT costs are also economically achievable. The BCT limitations passed the two part BCT cost reasonableness test.

E. Produced Water

1. BCT

As discussed in section XI.A, BCT limitations for produced water are equal to BPT. Therefore, there are no incremental costs and no economic impacts for produced water BCT limitations.

2. BAT

The cost of compliance for produced water limitations will be highest in the year in which the regulation goes into effect, because all existing structures must either meet the new limits with their current equipment and operation, upgrade their equipment and operation, or cease discharges of produced water. These impacts will diminish in time as existing projects come to the end of their economic life. For BAT produced water options, then, year 1 costs are the highest costs.

Total capital costs of the BAT limitations set by this rule are estimated to be $431 million. Annual operating and maintenance costs of $52 million also includes costs for two years of monitoring radium content of the produced waters. (This rule is not requiring radium monitoring of produced water. Monitoring costs of $3.4 million per year (1991 dollars) for the first two years of the analysis were included in the economic impact analysis to project impacts of such a monitoring requirement on facilities and companies. A radium monitoring requirement of finite, and relatively short-lived, duration is more appropriately implemented by permitting authorities and is not part of this regulation.) The annualized incremental cost in year 1 of the regulation is estimated to be $108 million and declines to zero in year 15. (All costs are in 1991 dollars.)

The EIA includes impacts of the options considered on each type of model platform. Selected impacts and model platforms are presented here for a Gulf-12 oil and gas platform (10 producing wells) and an oil and gas producing single-well structure with its own production and treatment equipment (Gulf-1b model, considered most sensitive to the costs of the regulation). For an existing Gulf-12 platform needing new treatment equipment to comply with the effluent limits of this rule, the net present value of the project declines by 3.6 percent while the corporate cost per BOE increases by 2.7 percent. For an existing Gulf-1b platform, the net present value declines by 35 percent, the corporate cost per BOE increases by 25 percent, and the project is assumed to cease production operations one year early because of increased annual costs of operation. The total loss in future hydrocarbon production from existing structures due to increased regulatory costs from the rule is approximately 0.4 percent (14.7 million BOE) over the 15-year period analyzed.

The BAT limitation of this rule leads to an estimated decrease of less than 0.5 percent in the working capital of a typical major company engaged in offshore energy production and is projected to reduce the working capital of a typical independent company by 3.7 percent. EPA finds the costs of the final BAT limitations for produced waters to be economically achievable for the oil and gas industry.

3. NSPS

NSPS costs are small in the first year of the regulation, covering only the structures installed that year. NSPS costs continue to grow over time as more structures are installed. By the fifteenth year, the number of new source platforms going out of production is assumed to equal, or exceed, the number of new source platforms beginning production. Thus, the cost in the 15th year of the regulation is assumed to represent a peak NSPS cost. The total capital cost for the selected option is $96 million while the annual operating and maintenance costs are $6 million. The annualized cost in the 1st year is $1 million and $14 million in the 15th year. (All costs are in 1991 dollars.)

For a new Gulf-12 platform, the limits on produced water set by this rule are estimated to decrease the net present value by 1.4 percent while the corporate cost of production increases 0.5 percent. The NSPS economic models consider all costs from lease purchase, through platform installation, and operation. The BAT model considers only the cost of continuing operations past its midlife. For a single-well structure that has its own production equipment (i.e., a Gulf-1b), the net present value is smaller for the NSPS project than for the BAT project. This indicates that by the mid-life of a single well structure, the initial costs still have not been recovered. Under these circumstances, the same absolute decrease in net present value will appear as a greater impact on the NSPS project because of the smaller baseline value. This is what is seen under the selected limitations for this rule; the net present value for the single-well structure declines by 66 percent under NSPS, while the corporate cost of production increases by 3 percent. If new equipment is needed, the single-well project may cease production a year early. Loss of future production over the 15-year period due to early closures is estimated at less than 0.1 percent (0.5 million BOE) of the production from new structures.

The selected NSPS limits for produced water would have virtually no impact on the working capital of a typical major oil company involved in the offshore and would reduce the working capital of a typical independent by 0.5 percent. According to EPA's analysis, the selected limitations would have no effect on oil and gas prices, employment, or international trade. EPA finds the cost of NSPS for produced water to be economically achievable for the oil and gas industry.

F. Produced Sand

The annual compliance cost for produced sand from BAT and NSPS sources under the selected option is estimated at $4 million (1991 dollars). No capital investments are expected to be associated with the limitations for this waste stream. The transport of the produced sand to shore and its subsequent disposal is assumed to be contracted to another company supplying such services. For BAT models, the financial summary statistics change by no more than 0.7 percent and there is no estimated loss in production. For NSPS models, if produced sand from a single-well structure (Gulf-1b model) contains elevated levels of NORM (naturally occurring radioactive material) such that disposal at a low-level radioactive disposal site is required, the net present value may decrease by 3 percent. For all other financial statistics and all other projects, the parameters change by no more than 0.5 percent. There is no loss of production associated with this limitation. The costs lead to negligible changes in financial ratios for typical major and independent oil companies engaged in offshore oil and gas production. EPA finds the costs of the BAT and NSPS zero discharge limitations for produced sand to be economically achievable.

G. Well Treatment, Completion and Workover Fluids

1. BCT

As discussed in section XI, BCT limitations for well treatment, completion and workover fluids are equal to BPT. Therefore, there are no incremental costs and no economic impacts associated with the BCT limitations for these wastestreams.

2. BAT and NSPS

Existing wells will bear the costs of additional controls on treatment and workover fluids prior to discharge. Larger structures are assumed to generate enough produced water that treatment and workover fluids can be treated within the produced water system without upset and without additional costs. Smaller structures, which may be unable to process the fluids without treatment system upsets, bear the costs of segregated treatment and workover fluid disposal. As with produced water, the cost of BAT limitation on oil and grease for treatment and workover fluids is highest in the first year of the regulation, when all existing wells are covered, and will decrease in time as the wells become unproductive and cease operations. The first year costs for BAT treatment and workover fluids is $1.7 million (1991 dollars). The changes in the per-project net present value and corporate cost per BOE are small, about 1 percent or less for all projects investigated. The costs of the BAT limitations for control of treatment and workover fluids are economically achievable.

Each new productive well drilled will need to meet the limitations on completion fluids. Once in production, these wells are anticipated to require treatment or workover on the average of once every four years. The treatment and workover fluids, like the completion fluids, must meet new limits on oil and grease. Larger structures are assumed to generate sufficient volumes of produced water to commingle these waste streams without upset to the produced water treatment system, so incremental costs would be borne only by smaller projects. The annual compliance cost for completion fluids is estimated at $0.2 million. The compliance costs for treatment and workover fluids would begin at negligible levels when the regulation first goes into effect and would peak at $0.8 million in the 15th year. (Costs are in 1991 dollars.) The financial summary statistics for all economic models change by less than 1 percent and there are negligible impacts on company financial ratios. EPA finds the BAT and NSPS limitations for treatment, workover, and completion fluids to be economically achievable.

H. Deck Drainage, Sanitary, and Domestic Wastes

The new limitations for these miscellaneous waste streams have no associated increase in compliance costs because they are either the same as BPT, permit requirements, or U.S. Coast

Guard limits. Therefore, there are no associated economic impacts.

I. Cost-Effectiveness Analysis

In addition to the foregoing analyses, EPA has performed a cost-effectiveness analysis for the selected options for drilling fluids and drill cuttings, produced water, and produced sand. According to EPA's standard procedures for calculating cost-effectiveness, all the options considered for each waste stream have been ranked in order of increasing pounds-equivalent (PE) removed (see the introduction to this section for a discussion of pounds-equivalent, a methodology for putting pollutants of differing toxicity on a comparable basis.) The cost-effectiveness value calculated for produced sand includes only the estimated pollutant removals for radium. EPA believes that had specific data on other known constituents (heavy metals and organics) in produced sand been available, the cost-effectiveness for produced sand limitations in the rule would be considerably less than the reported $291 per pound-equivalent. Cost-effectiveness is calculated as the ratio of the incremental annual costs to the incremental pounds-equivalent removed for each option. So that comparisons of the cost-effectiveness among regulated industries may be made, annual costs for all cost-effectiveness analyses are reported in 1981 dollars.

In 1981 dollars, the incremental cost-effectiveness for the selected options are:

—$44/PE—drilling fluids and drill cuttings
—$33/PE—BAT produced water
—$17/PE—NSPS produced water
—$291/PE—produced sand (only radium removal was used to calculate pound-equivalent of pollutant reduction for this waste stream).

J. Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*, requires that EPA prepare a Regulatory Flexibility Analysis (RFA) for regulations that have a significant economic impact on a substantial number of small entities. This analysis may be done in conjunction with or as a part of any other analysis conducted by EPA. The purpose of the RFA is to ensure that, while achieving EPA's statutory goals, the Agency has considered regulatory options for minimizing the cost of compliance on small entities.

The economic impact analysis described above indicates that the expenses necessary to meet the final effluent limitations guidelines and standards for the offshore oil and gas industry will be incurred by major and independent oil companies. These are not "small entities" by any standard. Additionally, the analysis has determined that none of the companies directly affected by this rule are small entities. Therefore no formal Regulatory Flexibility Analysis was proposed and EPA certifies that this rule will not have a significant economic impact on a substantial number of small entities.

K. Paperwork Reduction Act

Today's rule places no additional information collection or record-keeping burden on respondents. Therefore, an information collection request has not been prepared and submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et. seq.*

XV. Executive Order 12291

A. Introduction

Executive Order 12291 requires the Environmental Protection Agency and other agencies to perform a Regulatory Impact Analysis (RIA) of major regulations. Major rules are those which impose an annual cost to industry of $100 million or more, or meet certain other economic impact criteria. The RIA prepared by EPA for this rule may be obtained at the address listed at the beginning of the preamble. This RIA was submitted to OMB for review as required by Executive Order 12291.

The RIA analyzes the effect of current discharges and benefits of final limitations for the major waste streams from offshore oil and gas drilling (e.g, drilling fluids and drill cuttings), and production activities (e.g., produced water) on the offshore environment. Three types of benefits are analyzed: quantified and monetized benefits, quantified and non-monetized benefits, and non-quantified and non-monetized benefits.

The monetized benefits analysis focuses on the human health-related benefits of the regulatory options considered. These health risk reduction benefits are associated with reduced human exposure to various carcinogenic and noncarcinogenic contaminants, including lead, by way of consumption of shrimp and recreationally caught finfish from the Gulf of Mexico. Major toxic effects by lead in humans include inhibition of heme synthesis, kidney disfunction, and damage to the central nervous system. Broad symptoms include increased blood pressure and reduced learning ability. The lead related benefits include: (1) Decreased infant mortality; (2) reduced I.Q. impairments in children; and (3) reduced risks of hearth disease, strokes, hypertension and death. All benefits were estimated using a saltwater leach scenario for calculating the bioavailability of lead in the marine environment.

Other benefits that are quantified, to the extent possible, but not monetized due to lack of appropriate data, include: (1) Human health risk reductions associated with systemics other than lead, pH-dependent leach rates, carcinogens for which there are no risk factors available, exposure to pollutants via sediment or food chair; (2) ecological risk reductions; (3) fishery benefits; and (4) intrinsic benefits.

The combined monetized benefits of regulating drilling fluids, drill cuttings, and produced water in the offshore subcategory of the oil and gas extraction industry are found to be reasonably commensurate with their costs. The total monetized benefits for selected options (in 1991 dollars for the Gulf of Mexico only) range from $28 to $104 million annually. Hypertension effects were estimated based on a dataset with a median blood lead concentration of 15 µg/dL. Average blood lead concentrations are around 4.5 µg/dL. There may be uncertainty associated with the estimate of hypertension effects, because EPA has assumed that the relationship between hypertension effects at 4.5 µg/dL is the same as the 15 µg/dL blood lead concentration. The monetized benefits associated with hypertension risk reduction are $0.2 million. The total annualized BAT and NSPS costs in the Gulf of Mexico are $122 million in the first year and decline to $32 million in the 15th year following promulgation. Quantified-monetized benefits are based solely on the predictive health-related impacts. Benefits associated with regulating drilling fluids and drill cuttings predominate over those associated with regulating produced water; for drilling fluids and drill cuttings, lead-related benefits predominate over carcinogen-related health benefits.

The quantified, non-monetized benefit assessment includes a review of case studies of environmental impacts of drilling fluids and drill cuttings and produced water that document adverse chemical and biological impacts resulting from discharge of these wastes in the Gulf of Mexico, Atlantic, California and off Alaska and water quality analysis. A comprehensive review of available data (over 1000 references, plus EPA's Ocean Data Evaluation System (ODES) database) show documented local impacts for drilling fluids and drill cuttings discharges (22 case studies) and for produced water discharges (7 case studies). Geographically widespread marine impacts are not well documented. In preparing a water quality analysis for this rule, EPA used as a baseline permit conditions imposed by the Region 6 general permit for the OCS of the Gulf of Mexico, 51 FR 24897 (July 9, 1986). EPA projected exceedences of marine water quality criteria and toxic benchmarks, which are factors that EPA takes into account in making a determination of whether a discharge will cause unreasonable degradation of the marine environment. See 40 CFR 126.122(a)(10).

Discharged drilling fluids and drill cuttings are shown to cause contamination of sediments with heavy metals and hydrocarbons up to 4000 meters from the platforms. Other documented impacts include decline in abundance of benthic species (up to 1000 meters from the platform), reduced bryozoan coverage (within 2000 meters of discharge), altered benthic communities (up to 300 meters from platforms), bioaccumulation of heavy metals known to be present in drilling fluids and drill cuttings by benthic organisms, complete elimination of seagrass (within 300 meters of discharge), inhibited growth of seagrass (up to 3,700 meters, from the discharge point), and decreased coral coverage.

Produced water discharges are shown to cause contamination of sediments with metals and polynuclear aromatic hydrocarbons (PAH) up to 1000 meters from the platforms. Other significant impacts include reduction of benthic organisms (to below background levels) up to 300 meters from platforms, alteration of benthic communities (mostly toward opportunistic species), and sub-lethal (chronic) impacts to biota at distances in excess of 500 meters from the discharge point in high energy, open ocean environments.

The RIA uses models to project water quality impacts based on section 403(c) marine water quality criteria and human health risks from consumption of fish (consumed by recreational fishermen) and commercially caught shrimp (consumed by the general population) as a result of the offshore oil and gas discharges from existing and new offshore oil and gas platforms in the Gulf of Mexico. The "baseline," representing limitations under the 1986 general permit for the OCS in the Gulf of Mexico, and regulatory options considered for BAT and NSPS limits are assessed. The Gulf of Mexico was selected as a case study area because more than 90 percent of the offshore oil and gas exploration and production activities occur in this region, and because of its importance for commercial and recreational fishing.

The RIA attempted to quantify and monetize the specific environmental benefits that may result from the options considered for this rule. However, the high dilution afforded by the marine environment resulted in modeled pollutant concentrations that were sufficiently low that no directly quantifiable impacts on the Gulf of Mexico fishery could be attributed to the platform-related discharges. Predictions could not be made to quantify direct impacts of current discharges and benefits of options considered for this rule on composition and abundance of finfish and shellfish populations, recreational fishing and other recreational activities, commercial fishing, or nonuse benefits. Therefore, the RIA for this rule focuses exclusively on the benefits associated with human health risk reduction through modeled reduction in concentration of platform-related pollutants in recreationally-caught fish and commercially caught shrimp. Both carcinogenic and systemic human toxicant effects are considered. These quantified and monetized incremental benefits are compared to the annualized incremental cost in the Gulf of Mexico for the BAT and NSPS control options considered for this rule.

The non-quantified, non-monetized benefits assessed in this RIA include increased recreational fishing, increased commercial fishing, improved aesthetic quality of waters near the platform, and benefits to threatened or endangered species in the Gulf of Mexico. Recreational fishing benefits may be realized because (a) regulations may change perceptions about the risk to health posed by fish caught near the platforms, thus encouraging recreational fishing near the rigs and increasing fishing values; (b) to the extent anglers perceive that water quality near the platforms has improved, they may fish more often near the platforms thus increasing their participation; and (c) reduced discharges may improve the ecosystem in a way that enhances the fishery. For example, reduced pollutant concentrations would positively affect lower-level organisms in the food chain, improve reproductive success, increase the ability to avoid predation and improve growth.

Since data are not available to evaluate these hypotheses, EPA has not predicted potential recreational fishing benefits. However, if the regulations do have a positive impact on recreation, then the benefits of improved recreational fishing could be substantial. For example, even a 0.1 percent increase in recreational value would increase recreational fishing benefits by about $12 to $14 million.

Non-use benefits associated with improved water quality could be potentially significant. In freshwater settings, studies show that such benefits were no less than 50 percent of the associated recreational values.

The regulation may also have a beneficial effect on two federally-designated endangered species—the Kemp's Ridley Turtle and the Brown Pelican—that use the Gulf of Mexico as part of their habitat.

The commercial fishery in the Gulf of Mexico is a vital component of the regional economy. While there are data to suggest correlation between oil and gas extraction activities and fisheries catch statistics, definitive causal relationships cannot be developed. However, indirect impacts on the size or composition of the fishery, or on consumer demand for Gulf fishery products, may generate commercial fishery benefits.

B. Drilling Fluids and Drill Cuttings

The water quality analysis is performed for water column and sediment pore water quality impacts using mean seawater leachability (with mean leach percentages experimentally derived in seawater medium). Water quality impacts and benefits are projected for 23 pollutants representing average subcategory-wide drilling discharges.

The estimated human health benefits for the BAT and NSPS drilling fluids and drill cuttings limitations are in the range of $28 to $104 million (for seawater leach) compared to a projected incremental annualized cost of $19 million (in 1991 dollars for the Gulf of Mexico only) (Table 11) based on the combined quantified average risk reduction associated with consumption of fish and shrimp contaminated by lead and arsenic from drilling fluids and drill cuttings discharges. An additional reduction in human health risk from the subsistence fishing near the platforms is also anticipated but could not be quantified by this RIA.

Table 11.—INCREMENTAL ANNUALIZED BENEFITS AND COSTS FOR DRILLING FLUIDS AND CUTTINGS BAT/NSPS OPTIONS

[Millions of 1991 dollars per year; Gulf of Mexico only]

Regulatory option	Annual benefits [a]	Annual cost
3 Mile Gulf/CA [b]	$28.1-$103.6	$18.8

Table 11.—INCREMENTAL ANNUALIZED BENEFITS AND COSTS FOR DRILLING FLUIDS AND CUTTINGS BAT/NSPS OPTIONS—Continued

[Millions of 1991 dollars per year; Gulf of Mexico only]

Regulatory option	Annual benefits[a]	Annual cost
8 Mile Gulf/3 Mile CA	28.5–104.7	33.1
Zero Discharge Gulf/CA .	30.0–110.5	142.4

[a] Relative to baseline of current practice.
[b] Regulatory option selected for this rule.

C. Produced Water

The water quality analysis is performed for water column water quality impacts. Water quality impacts and benefits are projected for 29 pollutants representing average subcategory-wide produced water discharges.

The estimated human health benefits for the BAT limitations of the final rule, based on the quantified average risk reduction associated with the consumption of platform-contaminated fish for three carcinogens (arsenic, benzene, benzo(a)pyrene) and one systemic toxicant (lead), are estimated to range from $30,000 to $123,000, versus a projected incremental annualized cost of $102 million in the first year that declines to zero in the 15th year (in 1991 dollars for the Gulf of Mexico only) (Table 12). The estimated human health benefits for the NSPS limitations (based on the same pollutants) are estimated to range from $39,000 to $162,000, versus a cost of $1 million in the first year that rises to $13 million in the 15th year (in 1991 dollars, for the Gulf of Mexico only) (Table 13). An additional reduction in human health risk due to subsistence fishing near the oil and gas platforms in the Gulf of Mexico region is also anticipated but could not be quantified by this RIA.

TABLE 12.—INCREMENTAL BENEFITS AND COSTS FOR PRODUCED WATER BAT OPTIONS

[Millions of 1991 dollars per year; Gulf of Mexico only]

Regulatory option	Annual benefits[a]	Annualized cost in year 1	Annualized cost in year 15
Flotation All[b]	$0.030–$0.123	$102.2	0.0
Zero 3 Miles Gulf and Alaska[c]	0.28–1.42	123.8	0.0
Zero Discharge Gulf and Alaska[c]	0.54–2.78	730.3	0.0

[a] Relative to baseline of current practice.
[b] Regulatory option selected for this rule.
[c] Benefits associated with controlling Ra–226 and Ra–228 are considered only for options that include zero discharge.

TABLE 13.—INCREMENTAL BENEFITS AND COSTS FOR PRODUCED WATER NSPS OPTIONS

[Millions of 1991 dollars per year; Gulf of Mexico only]

Regulatory option	Annual benefits[a]	Annualized cost in year 1	Annualized cost in year 15
Flotation All[b]	$0.039–$0.16	$0.9	13.4
Zero 3 Miles Gulf and Alaska[c]	0.30–1.5	3.9	57.7
Zero Discharge Gulf and Alaska[c]	0.55–2.8	25.0	375.5

[a] Relative to baseline of current practice.
[b] Regulatory option selected for this rule.
[c] Benefits associated with controlling Ra–226 and Ra–228 are considered only for options that include zero discharge.

XVI. Public Participation and Summary of Responses to Major Comments

Public participation in the development of the effluent limitations guidelines and standards for this industry has been extensive. Throughout the development of this regulation, EPA has made numerous documents available to the public for comment and has held public meetings for the purpose of providing information and receiving information and views from many individuals and organizations.

The public comment period for the 1985 proposal, set originally for three months, was extended to provide a total of six months for comment. Partly in response to these comments and partly to incorporate supplemental data, EPA modified its data base, methodologies and regulatory approaches and discussed these changes in a Notice of Availability and request for comments on October 21, 1988 (53 FR 41356). The comment period for this Notice of Availability, originally set for six weeks, was subsequently extended to provide a total of three months for comment.

On November 26, 1990 (55 FR 49094), EPA published a proposal and reproposal presenting additional modifications to the data base and changes to methodologies and regulatory approaches. A one month comment period was provided for this proposal.

On March 13, 1991 (56 FR 10664), EPA published a subsequent proposal describing the November 1990 proposal in greater detail and setting forth additional technical, economic, environmental, and other information relating to the establishment of effluent guidelines and standards for the offshore subcategory. The comment period for this proposal was originally set for one month. EPA subsequently extended the comment period for the majority of the proposal by an additional month, with several key issues extended to provide a total of three months to comment. In response to the notices and proposals discussed above, EPA received 145 submissions of comments and data from industry, government, environmental and other groups, and individuals. These submissions comprise over 5,000 pages.

Throughout this rulemaking, EPA has not only welcomed the submission of comments, but also solicited data that could be used to supplement, correct, or fill gaps in EPA's data base. Where adequately documented data of sufficient quality were submitted, EPA used the data along with other data it had collected. EPA believes that it has made all reasonable efforts to obtain public input on this rule.

Included in the record for this rule is a large response to comments document. The sheer volume of comments precludes the publication of EPA's responses to all of them in this preamble. EPA has discussed and responded to some comments earlier in this preamble. Other comments are responded to in the separate response to comments document mentioned above. Finally, the various data compilations, editing, and other information contained in the record for this rule address (and in some instances were obtained or acquired specifically for the purpose of addressing) the public comments.

A. Cadmium and Mercury BAT and NSPS Limitations for Drilling Fluids and Drill Cuttings

Comment: Several commenters expressed opposition to establishing BAT and NSPS limitations on cadmium and mercury in drilling fluids and drill cuttings wastestreams at 1 mg/kg each, as measured in the whole drilling fluid. The commenters cited data indicating that the geologic formation can act as a contributor of cadmium to the drilling fluid, and recommended establishing the metals limits in the stock barite rather than "end-of-pipe." Some industry commenters suggested a stock barite limitation of 3 mg/kg cadmium and 1 mg/kg mercury, while others suggested a limit of 5 mg/kg cadmium and 3 mg/kg mercury in the stock barite.

Response: EPA agrees that the limitations on cadmium and mercury should be set in the stock barite. The final BAT and NSPS limits for drilling fluids and drill cuttings include limitations on cadmium and mercury at 3 mg/kg and 1 mg/kg (dry weight), respectively, in the stock barite. This is not an effluent limit to be measured at the point of discharge, but a standard pertaining to the metals content of the barite used to formulate drilling fluids. Compliance with the limitation would involve the use of barite from sources that either do not contain these metals or contain the metals at levels below the limitation.

EPA has analyzed data from the American Petroleum Institute's Fifteen Rig Study. In this study, samples of drill cuttings, used drilling fluid, and barite from a number of drilling sites were sampled for metals content. Results of EPA's statistical analysis indicate that some cadmium present in the drilling fluids came from a source other than the barite.

Establishing the final metals limitations on the stock barite, rather than "end-of-pipe" in the whole drilling fluid at the point of discharge, is consistent with EPA's original intent for control of drilling fluids and drill cuttings. EPA's technology basis for limits on metals content in drilling wastes has always been product substitution of "clean" barite sources containing low levels of impurities as a substitute for "dirty" barite with higher concentrations of impurities. In section VII.B of the preamble, EPA discusses why the limits selected for the final rule are available and economically achievable.

B. Clearinghouse Approach for Controlling Toxicity of Drilling Wastes

Comment: Several industry commenters have stated that EPA should use a "clearinghouse" approach to control toxicity for drilling fluids and drill cuttings, rather than establish "end-of-pipe" toxicity limits. Instead of measuring compliance through bioassay of drilling wastes, a clearinghouse approach would project the cumulative toxicity of the drilling fluids and additives in advance based on mud formulation.

Response: In the 1985 proposal, one of the options proposed for limiting the discharge of muds was referred to as the "Clearinghouse/Toxicity Approach" (50 FR 34592). The clearinghouse concept is based on the fact that operationally satisfactory drilling fluids can be formulated by substituting less toxic constituents. Under a clearinghouse concept, a list of effective muds that could be discharged from offshore operations would be compiled. The generic drilling fluid concept was developed in 1978 when EPA instituted a joint testing program for various formulations for operations in the Atlantic Ocean lease sale areas. EPA Region 2 and the Offshore Operators Committee (OOC) conducted the Mid-Atlantic Bioassay Program which identified eight water-based drilling fluid types (generic fluids) that encompassed virtually all types of drilling fluids in use at the time. The generic fluids were then bioassayed once as an alternative to having the participating operators perform bioassay and chemical tests every time a discharge occurred. To allow for the use of acceptable additives in drilling operations, EPA and the OOC also developed the concept of an "approved" additives list. An operator could submit bioassay data on a mud containing a particular additive to EPA for review. If EPA "approved" the additive, operators were then allowed to discharge the generic fluid types, including certain approved specialty additives ("additives"), without conducting additional testing (50 FR 34603). Other EPA Regions used the results from the generic fluids testing in permits issued for Outer Continental Shelf (OCS) lease areas, and the 1985 proposal also contained another option (Option 1, 50 FR 34607) which limited toxicity to 30,000 ppm for the suspended particulate phase (SPP) based on the results of bioassay program.

In the 1985 proposal, Option 2—Clearinghouse Approach discussed the establishment of a national clearinghouse to be administered by EPA. Under this option, EPA would serve as a repository for all toxicity and related physical and chemical characteristics of base drilling fluid formulations and additives. The information would be used by the public and operators for use in selecting fluid/additive formulations that would likely comply with the established toxicity regulations (50 FR 34608).

EPA Region 10 later issued several NPDES general permits (Bering and Beaufort Seas (49 FR 23734, June 7, 1984) Norton Sound (50 FR 23578, June 4, 1985), Cook Inlet/Gulf of Alaska (51 FR 35460, October 3, 1986), Chukchi Sea and Beaufort Sea II (53 FR 37846, September 28, 1988)) in which the discharge of certain additives was authorized without further bioassay testing if discharged in generic drilling muds. In all of its permits, Region 10 authorized the discharge of certain muds and a variety of specialty additives listed on tables in the permits. When operators needed to use muds or additives not directly authorized on the tables, Region 10 evaluated available bioassay data and authorized discharge (or not) based on its BPJ estimate of the cumulative toxicity for the proposed discharge. Region 10 often required bioassay of the discharged muds/additives at maximum (discharge) concentrations in order to obtain bioassay data that represented practical product concentrations and actual discharge toxicity. Region 10's approach was based on additivity (meaning that the toxicity of the whole drilling fluid could be estimated based on the toxicity of the constituents) because there were no other practicable ways in which to address available bioassay data.

In the 1985 proposal (50 FR 34592) and the 1991 proposal (56 FR 10664), EPA rejected the Clearinghouse option based on the time required to develop such a program, and the complexity of managing such a program on a national level. Although EPA has received comments in favor of a clearinghouse approach to fluids/additive discharge authorization, several important reasons remain that support rejection of this regulatory option.

First, EPA's NPDES permitting program (section 402 of the Act) is based on point of discharge ("end-of-pipe") accountability. While bioassays of drilling wastes to be disposed of are an established measure of compliance with "end-of-pipe" toxicity limits, a clearinghouse approach would require the cumulative toxicity of the fluids and additives to be projected in advance. These advance estimates would have to be performed for each discharge of drilling fluids by hundreds of offshore wells annually. Whether EPA performs the estimates or industry submits them for Agency review, because of the large number of drilling operations in the offshore subcategory the administration of such a program would be complex and would place a huge administrative burden on the Agency. Compounding this, EPA would be required to maintain a data base with up-to-date information on fluids and additives, provide resources to track the data, and respond to challenges to clearinghouse determinations.

Although it has been demonstrated that the clearinghouse systems can be effective on a small scale, EPA has reservations regarding the feasibility of a nationwide program. The success of the Region 10 program is due, in large part, to the relatively small number of wells drilled in the past and estimated for the future. (The projected number of new drillings for the Region 10 offshore area is 12 per year). A national clearinghouse program involving over 700 new drillings per year and requiring maintenance and updating of a database containing information on numerous additives and fluids combinations would be much more difficult to manage and would place an enormous burden on the Agency.

For these reasons, EPA rejected the clearinghouse option as a component of nationally applicable regulations; however, this would not necessarily preclude EPA Regions from using a clearinghouse approach in permits as a means of implementing the toxicity limits in these regulations, if appropriate.

C. Synthetic Drilling Fluids

Comment: Several industry commenters noted recent developments in formulating new drilling fluid systems (e.g. vegetable oils, synthetic hydrocarbon-based fluids, polyolefins) as substitutes for the traditional water-based and oil-based (diesel or mineral oil) drilling fluids. Industry commenters contend that the new drilling fluids are potentially much less toxic than many of the more traditional drilling fluids currently in use. However, the newer fluids are not being used because they are costly and because they are likely to cause a discoloration on the receiving waters. This discoloration may be interpreted as a "sheen" which is the mechanism specified for determining compliance with the existing BPT limit and the BCT and BAT limits and NSPS established in this rule for no discharge of free oil from drilling fluids and drill cuttings. The newer fluids may cause a sheen even where there has been no discharge of diesel or mineral oil or hydrocarbons from the well. In other words, the static sheen test cannot distinguish between drilling fluids and drill cuttings containing these newer drilling fluids and drilling fluids and drill cuttings contaminated by diesel oil, mineral oil, or formation hydrocarbons. For these reasons, industry commenters further contend that these newer drilling fluids should be exempt from compliance with the no free oil limitation required by these effluent limitations and NSPS.

Response: EPA disagrees with the commenters' assertion that certain drilling fluids should be exempted from the BCT and BAT limitations and NSPS established in this rule prohibiting discharge of free oil in drilling fluids and drill cuttings as determined by the static sheen test. The technology basis for the no free oil requirement, onshore treatment and/or disposal of drilling fluids and drill cuttings is applicable to all drilling fluid systems and prevents discharge of substantial quantities of conventional, non-conventional and priority pollutants. The prohibition on discharge of free oil was originally established under BPT to prevent discharges of drilling waste contaminated with diesel oil, mineral oil, or formation hydrocarbons to surface waters. Since mineral oil or diesel oil is occasionally added to a drilling fluid system to enhance lubricity or as a pill to free stuck pipe, or hydrocarbons from the formation may enter the drilling fluid system during drilling operations through oil-bearing geologic strata, the prohibition on discharges of free oil remains an appropriate limitation for discharge of drilling fluids and drill cuttings.

While EPA agrees that some of the newer drilling fluids with non-mineral oil or non-diesel oil bases may be less toxic and more readily biodegradable than many of the drilling fluids currently in use, EPA is concerned that there is no method 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.

At the same time, EPA wants to encourage development of less toxic drilling fluid substitutes or drilling fluids with a higher degree of biodegradability if an alternative method can be developed to distinguish between discharge of diesel oil, mineral oil, or formation hydrocarbons in drilling fluids and drill cuttings from discharges of these newer drilling fluids. EPA solicits data on alternative ways to differentiate between these two kinds of discharges, including gas chromatography or other analytical methods. EPA also solicits information on technological issues, related to the use of these newer fluids (*e.g.*, under what geological conditions and for what part of the drilling operations can these newer drilling fluids be used), any toxicity data or biodegradation data on these newer fluids, and cost information. EPA will consider this information, and if appropriate, issue guidance on use of the static sheen test for distinguishing these newer drilling fluids from mineral oil-based fluids, diesel oil-based fluids or formation hydrocarbons. Also, if appropriate, EPA may propose alternative analytical methods or undertake other rulemaking to address this issue.

EPA acknowledges that the current Gulf of Mexico general permit prohibits the discharge of inverse emulsion drilling fluids, which are defined as oil-based drilling fluids which also contain a large amount of water. EPA solicits information on whether newer drilling fluids should be considered inverse emulsion fluids and what effect the current permit prohibition on discharge of inverse emulsion fluids will have on the ability to discharge newer, non-petroleum oil-based synthetic fluids if they pass the static sheen test, along with the other limitations applicable to drilling fluids and drill cuttings.

D. Non-Water Quality Environmental Impacts—Drilling Wastes

EPA received several comments regarding non-water quality environmental impacts associated with the limitations on discharges of drilling fluids and drill cuttings. These comments related primarily to the volumes of drilling fluids and drill cuttings that would need to be disposed and the number of vessels available to transport drilling fluids and drill cuttings to shore for disposal.

Comment: EPA received comments suggesting that the assessment of non-water quality environmental impacts (and any regulatory determination based on these impacts) should be based on drilling waste volumes which result from operators using enhanced solids control systems. The commenter contended that by basing drilling waste volume estimates on enhanced solids control systems, the volume of drilling wastes requiring onshore disposal (as well as the necessary boat trips and associated energy usage and air emissions) would be substantially reduced.

Response: EPA believes that it made a reasonable estimate of the quantity of drilling fluids and drill cuttings that would be required to be disposed of onshore under the rule. EPA's estimate of the volume of drilling waste generated offshore is based on actual discharge data and is demonstrative of the fairly high level of solids control employed offshore.

Solids control equipment is used by the industry to remove drill cuttings and minimize the buildup of drilled solids in the drilling fluid system. In addition to enhancing drilling fluid properties, by minimizing solids buildup in the mud system the operator can reduce the extent to which dilution of the drilling fluid is required. All drilling operations utilize solids control equipment to some degree and the efficiency of the system, in determining the extent to which dilution is required, affects the volume of drilling wastes generated. A relatively low efficiency (40 percent) solids control system requires a substantial level of dilution in order to maintain proper mud system properties. Intermediate level of efficiency (about 60 percent), in providing greater solids removal from the mud system, substantially reduces the level of dilution required for the mud system and reduces the volume of drilling wastes generated. The intermediate level system will result in an increased volume of drill cuttings and a decreased volume of drilling fluids. (While the total drilling waste volume is reduced because of the reduced dilution, a portion of drilled solids discharged along with drilling fluids in low efficiency solids control systems will be removed by the higher efficiency solids control and included with the drill cuttings wastes.)

Finally, closed-loop solids control systems can provide approximately 80 percent solids removal efficiency, further reducing the overall drilling waste volume (the drill cuttings volume would increase, but the drilling fluid volume decreases by a greater amount.) While the closed-loop system provides volume reductions over the intermediate-level system, the volumetric reductions in waste generation are not linearly proportional to the solids control efficiency. As a result, operators gain significantly greater reductions in drilling waste volumes in going from low efficiency to intermediate level solids control equipment than achieved in going from intermediate-level equipment to closed-loop systems.

In developing the final rule, EPA considered solids control equipment practices used in the offshore oil and gas industry. In evaluating the potential for enhanced solids control systems to reduce drilling waste volumes (and thus reduce non-water quality environmental impacts), EPA reviewed industry literature and solids control equipment currently used in offshore drilling situations and data on solid removal efficiencies. Based on the limited data available, EPA has determined that the offshore oil and gas industry, while not using the highest efficiency solids control systems available, is in general using a fairly high level of solids control in drilling operation.

While most platforms and drilling rigs may have a basic level (relatively low efficiency) of solids control equipment permanently installed, it is common industry practice for lease owners/ operators, in contracting with the service firms providing drilling services, to require some level of enhanced solids control equipment to be used. EPA used industry data on drilling waste discharges, (for which solids information was unavailable) in conjunction with theoretical estimate of drilling waste volumes (calculated from the theoretical hole volume and use of solid control equipment with differing efficiencies), to determine that waste volumes generated in the offshore subcategory are demonstrative of a fairly high solids control efficiency.

A factor to be considered in offshore operations is whether available space exists on the platform or mobile drilling rig to support installation of higher efficiency solids control equipment. In onshore and coastal areas, drilling operations typically are not severely limited in terms of equipment space. (In coastal regions, additional equipment can often be added on the drilling barge or an additional barge brought to the drilling site.) Offshore, however, operators must balance the benefits of adding additional solids control equipment with the need to reserve space on the platform or drilling rig for storage of drill cuttings boxes. If the available space for storage of drill cuttings boxes becomes too limiting, additional boat trips to remove the drill cuttings are required if interruptions to the drilling operation are to be prevented. Also, installing higher-efficiency solids control equipment produces a greater drill cuttings volume, further limiting drilling operations. (While the drilling fluid volume is decreased, a corresponding space availability does not result since the muds are stored in tanks which have a smaller "footprint", or surface area requirement. Operators are limited in the extent to which cuttings boxes may be stacked.) Operators may retrofit additional platform space on platforms or mobile drilling rigs; however, in some cases such modifications may not be feasible and in any case would be made upon economic consideration of modification costs and onshore waste disposal costs.

In evaluating the impact of enhanced solids control equipment drilling waste volumes requiring onshore disposal, EPA used its estimates of current industry practice, platform addition costs, and onshore disposal costs to assess the potential for operators to further enhance their solids control systems. EPA was limited in this analysis by the lack of facility-specific data regarding the installed solids control equipment. Because the industry is already using a fairly high level of solids control (limiting the extent to which benefits could be realized through further efficiency increases), facility-specific data is lacking, and because the selection of the type of solids control system used at a particular drilling location depends on site-specific drilling conditions and economic variables, EPA was unable to determine the extent to which the industry would implement higher-efficiency solids control systems. To the extent that higher-efficiency solids control equipment may be utilized, some reduction in the total drilling waste volumes generated could be realized. Considering the fairly high level of efficiency already implemented offshore, such volume reductions would not likely be significant. Thus, EPA believes non-water quality environmental impacts estimated for drilling fluids and drill cuttings effluent limitations and NSPS would not change significantly with implementation of higher-efficiency solids control equipment.

Comment: EPA also received comments opposed to the comment above, that drilling waste volumes were understated and that additional boat trips would be necessary.

Response: EPA reassessed drilling waste volumes in developing the final rule in response to public comments. The projected volumes of drilling fluids and drill cuttings generated in the offshore subcategory have changed slightly since proposal due to revisions in calculations of: (1) The average well depth, based on an expanded set of drilling data; (2) the typical depth of a deep well (deep wells generate greater waste volumes than shallow wells because of the footage drilled and the larger diameter borehole used); and (3) the percentage of all wells drilled greater than the average industry offshore well depth. The methodology used to calculate the drilling waste volumes is unchanged from the proposal. In estimating the volume of drilling waste generated requiring onshore disposal, EPA revised downward projections of the usage of oil-based drilling fluids. This downward revision reduces the volume of drilling waste requiring onshore disposal. However, the decrease in onshore disposal by this revision is offset by the updated assumption of greater numbers of deep wells and the volume increase associated with these wells. For these reasons, EPA believes that the projected waste volumes presented in section VII of this preamble and the Development Document are accurate estimates of the volume of drilling fluids and drill cuttings requiring onshore disposal.

Comment: Some commenters contended that EPA's assumption regarding the number of vessels necessary for transporting the drilling wastes was an over-estimate. A commenter to the rule disputed EPA's 1991 projections of the number of supply boats needed to transport drilling wastes to shore. This commenter claimed that EPA inappropriately estimated drilling waste volumes, overestimated the number of dedicated supply boats needed, and failed to consider the potential for using regularly scheduled supply boats to carry drilling wastes to shore. The commenter claimed that the drilling wastes could be brought to shore by regularly scheduled supply boats and that EPA was double-counting the number of boat trips needed.

EPA also received opposing comments. One commenter claimed that there are no vessels (barges) configured and certificated to carry oilfield wastes authorized to operate in offshore waters, and noted the improbability of modifying the open hopper barge design often used in inland wasters. Some commenters contended that there were insufficient vessels available to transport the drilling wastes to shore.

Response: EPA strongly disagrees with the contention that vessels are unavailable for offshore service. EPA estimates that approximately 760,000 barrels per year of drilling wastes are transported from drilling sites in the offshore category to the shore for disposal in order to comply with the current BPT and NPDES permit limitations. These wastes are transported to shore by offshore service vessels, typically supply boats. The population of service vessels available to transport offshore drilling wastes is difficult to determine; however, estimates regarding the number of vessels and the increased requirements resulting from this rule can be made.

As discussed above, supply boats make frequent visits to drilling and production sites throughout the offshore subcategory. Service vessel usage at offshore facilities may be as high as two supply boats per day and two crew boats per day during the exploration and development phases. In general, service vessels make three trips per week to exploration and development operations and one trip per week to production platforms. (EPA projects future wells in the offshore subcategory to be drilled at the average annual rate of about 760 wells per year. There are currently approximately 2,550 production platforms in the offshore subcategory.) MMS data show that there were 25,000 service vessel trips to support oil and gas related activities on the OCS (federal waters only) in the Gulf of Mexico in 1988. These data do not differentiate between types of vessels; however, it does provide some indication regarding the boat population and level of activity. EPA estimates that transporting drilling wastes to shore in compliance with the requirements of this rule will result in an increase of about 740 service vessel trips per year. (See the Development Document and record for this rule.)

EPA disagrees with the contention that the number of boats needed have been double-counted, and also does not agree that drilling wastes could be brought to shore exclusively by regularly scheduled supply boats. In projecting the number of boat trips required and associated non-water quality environmental impacts, EPA determined that both dedicated and regularly scheduled supply boats will be used to transport drilling wastes to shore. In the early stages of drilling a well, drill cuttings are generated at such a rate and in sufficient quantity that platform storage space can be a limiting factor and dedicated boats are needed to collect the wastes and prevent interruptions to the drilling program. As waste generation rates decline (drilling rates decline and the well diameter becomes smaller as depth increases), dedicated boats are unnecessary and regularly scheduled supply boats are used to transport the drilling wastes to shore. At the end of drilling, a dedicated supply boat is again typically needed to remove the bulk drilling fluid remaining in the system.

Comment: Some commenters stated that there was insufficient onshore disposal capacity available to receive drilling wastes generated offshore.

Response: In this final rule, EPA updated estimates of the onshore disposal capacity for oilfield wastes. The onshore disposal capacity was estimated on a regional basis in developing the November 1990 and March 1991 proposals. These regional estimates were updated subsequent to the proposal and identified current permitted capacity near the coast, the volumes of oilfield wastes currently treated by those sites, and the "excess" disposal capacity available to accept additional waste volumes. The projections of onshore disposal capacity are discussed in more detail in section VII of this notice and the Development Document. EPA concludes that there is adequate onshore disposal capacity available to accept offshore drilling wastes requiring onshore disposal under this rule.

E. Toxicity Limitation for Drilling Fluids and Drill Cuttings

Comment: Numerous comments were received concerning the proposed toxicity limitation for drilling fluids and cuttings. Some commenters argued that the limit was too stringent, while one commenter argued that the limit was not stringent enough. Most of the comments related to the original proposal in 1985 to limit discharges of drilling fluids to only those fluids that complied with a toxicity limitation for the suspended particulate phase (SPP) of 30,000 ppm (3 percent of volume). Drill cuttings discharges were to be controlled by prohibiting the discharge of free oil. Because of the adherence of drilling fluids to the cuttings during the drilling operation, however, the toxicity limitation for drill cuttings was included in the 1991 proposal. Commenters to the 1991 proposal raised the same or similar issues either specifically describing them in their 1991 comments or by reference to their 1985 comments. In general, industry comments objected to the use of a toxicity limitation as being too stringent. Specifically, industry commenters said EPA had not demonstrated a correlation between toxicity and the amount of pollutants present in the drilling fluids waste stream, had not verified with actual field data that the 30,000 ppm (SPP) limits can be achieved consistently in actual drilling operations, and had not demonstrated that the limit can be met by drilling fluids which are necessary to drill safely and effectively on the outer continental shelf. Industry commenters also raised issues concerning the toxicity test protocol and the lack of quantified environmental benefits resulting from imposition of the toxicity limitation.

On the other hand, one commenter stated that the 1991 proposed toxicity limits of 30,000 ppm (SPP) were not stringent enough. The commenter stated that the 30,000 ppm (SPP) limit on mud toxicity is clearly not BAT and not even BPT. This commenter also raised questions concerning use of a toxicity test which does not take into account solid phase toxicity and chronic toxicity, including cumulative and sublethal effects. A toxicity limitation of 100,000 ppm (SPP) instead of 30,000 ppm (SPP) was recommended if EPA set a toxicity limit rather than establishing a zero discharge requirement. This recommendation was based on a draft Environmental Assessment Report (1982) citing data summarizing 415 toxicity tests of 68 muds using 70 species from an unspecified number of platforms. Because 44 percent of the data for the generic muds exhibited toxicity values greater than 100,000 ppm (SPP), the commenter recommended EPA raise the toxicity limitation to a minimum toxicity limitation of 100,000 ppm.

Response: Specific responses to the individual comments related to the 30,000 ppm (SPP) toxicity limitation are contained in the response to comments document for this final rule. A summary of the major portions of these responses is contained in this section of the preamble. This summary describes the basis for the 30,000 ppm (SPP) limitation, the appropriateness of the use of this limitation for all drilling activities and the suitability of the toxicity test method. In addition, an analysis of the economic impact of these limitations is discussed further in section XIV of the Preamble, the Economic Impact Analysis, and the record for the rule. A summary of comments concerning the environmental benefits or lack thereof is not contained in this section, but the individual comments are addressed in the comment response document and the environmental assessment conducted under Executive Order 12291, which is described in section XV of this Preamble.

Compliance with the toxicity limitation is based on the technologies of (1) product substitution of lower toxicity water-based or synthetic drilling fluids for higher toxicity drilling fluids and (2) transport to shore for ultimate land disposal of drilling wastes (fluids and cuttings) that do not meet the toxicity limits established by these regulations. As required by the CWA, BAT limitations are to be based on the best available technology and be economically achievable. NSPS are to reflect the greatest degree of effluent reduction which the Administrator determines to be achievable through application of the best demonstrated control technology, taking cost into consideration. Product substitution and transport to shore if the drilling fluids and drill cuttings to be disposed of will not meet applicable effluent limitations or NSPS, are the best available and best demonstrated technologies for controlling the discharge of toxic and nonconventional pollutants associated with the drilling fluids and drill cuttings wastestreams.

In response to industry comments that the limit is too stringent, EPA disagrees. EPA has determined that the toxicity limitation meets the statutory criteria for BAT and NSPS. EPA believes that the 30,000 ppm toxicity limit on drilling fluids is technologically achievable because industry has been operating under NPDES permits imposing such a limit since at least 1986 (General Permit for the Outer Continental Shelf in the Gulf of Mexico, 51 FR 24897). As discussed further below, the eight generic drilling fluids have properties that make them applicable to almost all drilling situations. Also, as discussed below, where more toxic drilling fluids are necessary, barging is available and adequate landfill disposal capacity exists to dispose of the drilling fluids and drill cuttings on shore.

With respect to the comment that a toxicity limitation of 30,000 ppm (SPP) is too lenient, the commenter argued that the toxicity limit (based on the most toxic of eight drilling fluids) establishes a least common denominator, rather than the highest common denominator demanded by the statutory definition of BAT and NSPS. EPA disagrees.

In looking at how to apply a product substitution approach, EPA worked with industry to identify water-based generic drilling fluids that are applicable to almost all drilling situations. Drilling fluids are complex mixtures of chemical constituents formulated to meet the individual requirements of each well. Many of the chemicals have numerous functions in the drilling fluids; however, individual chemicals usually have a primary function. Important functions which are performed by the drilling fluids are: the removal of drilled solids (cuttings) from the bottom of the hole to the surface where they are removed; the lubrication and cooling of the drill bit and string; the depositing of an impermeable layer (wall cake) on the well bore hole wall to seal the formation being drilled; the control of downhole pressure; the holding of drill cuttings in suspension within the fluid when circulation of the fluid is interrupted; the support of part of the weight of the drill bit and string; and the transmitting of hydraulic horsepower to the drill bit.

Drilling fluids are usually dense colloidal slurries which have several phases (generally a water phase and a solid phase, some also have an oil phase or a gas phase). The water phase may range from fresh to saturated salt mixtures. The fluids start with the water phase and clay, either bentonite or attapulgite clay. All of the generic fluids except one use one or the other of these clays. The one fluid composition which does not use either of these clays is the generic mud type #1, Seawater/ Potassium/Polymer Mud. This mud uses potassium chloride starch and a cellulose polymer. The use of these components in generic mud type #1 is necessary because of the loose shale conditions often encountered in the Gulf of Mexico. The potassium chloride functions as a shale control additive, the cellulose polymer functions as a filtrate reducer and shale controller and the starch functions as a filtrate reducer. Both of these functions are important in keeping fluids from the mud system from entering the formation and keeping the formation from collapsing into the hole.

The clays used in the drilling fluids (either bentonite or attapulgite) are very hydrophilic and form the basis of a viscous gel. As drilling continues, drilled clays (from the formation) may thicken the drilling fluid, thus requiring thinners and dispersant to be added to control flow or rheological characteristics of the fluid. These rheological properties involve the viscosity and gel strength of the fluid, and are important in determining frictional pressure losses (lubricity), and the ability of the fluid to lift cuttings to the surface. A number of constituents (or additives) are used as dispersants or thinners, such as the lignosulfonates, lignite, phosphates and plant tannins. Several of the generic mud types used in the toxicity limitation testing contained these constituents (Mud Types #2, #3, #7, and #8).

Additional constituents must be used in many drilling situations. These include barite, a weighting agent, which controls downhole pressure by raising the density of the fluid system; bentonite, starch or other compounds, which control fluid loss by building a filter cake on the wall of the bore hole; and various constituents for lubricity, plugging holes in the formation which cause loss of the entire drilling fluid slurry, and biocides to control bacterial growth which can interfere with the drilling and/or production activity.

Commenters identified numerous examples of the need for various compositions or types of fluids, generic or specialty, in order to drill in the different formation characteristics encountered in the Gulf of Mexico in particular.

For example, if an ineffective shale stabilizer is used, there could be severe hole problems which would cause increased drilling time and possible loss of the well; if the composition limits the amount of barite to that of the highest barite content in any of the generic muds, high pressure/high temperature drilling operations routinely encountered in the Gulf of Mexico could not be conducted; and the use of KCl (potassium chloride) muds for water sensitive shale formation control, although sporadic, are essential.

Because EPA believes that drilling fluids exhibiting the characteristics of the eight generic fluids are necessary for industry to conduct drilling operations in almost all drilling situations, EPA needed to set the compliance limit based on the most toxic of these eight fluids. EPA recognizes that even with product substitution, with the limit set at 30,000 ppm (SPP), there will be some instances in which the most toxic of the generic fluids or a more toxic drilling fluid or additive is needed to conduct drilling operations. The need for additional lubricity, or the need to stabilize the well bore hole, particularly in drilling through heavy shale formations are examples of the situations in which EPA believes the use of constituents or additives may require the drilling wastes to be transported to shore due to failure to comply with the 30,000 ppm (SPP) toxicity limitation. Thus, in these instances, transporting the drilling fluids and drill cuttings to shore would be the technology basis for compliance with the limit instead of product substitution.

In response to the comments that the 30,000 ppm (SPP) limitation is too lenient, EPA obtained the reported toxicity values of used drilling fluids and cuttings from monitoring required by the Gulf of Mexico General Permit (Permit No. GM280000) and several general permits from Offshore Alaska (Permit Nos. AKG284100, AKG288000, AKG283000, and AKG785000). Then EPA reviewed the distribution of these data. The available data do not include the level of information (described below) necessary to determine if the less toxic drilling fluids used to result in lower effluent toxicity could be used to address the myriad of drilling situations encountered in the field. Also, the probability distribution of the results does not follow any of the commonly used parametric distributions such as the normal or lognormal distribution. Thus, EPA could not determine whether the less toxic results could be related to some operational characteristics, nor could EPA extrapolate such a relationship based on these data.

Although the data show that drilling fluids and drill cuttings do have toxicity values higher (less toxic) than 30,000 ppm (SPP), EPA cannot establish a more stringent limit based on this information for a number of reasons. First, the data represent the drilling fluids that have been discharged. Thus, while the data indicate how frequently the drilling fluid discharges meet the 30,000 ppm (SPP) limit, EPA does not have firm information about the amount of drilling fluids and drill cuttings that are planned to be barged to shore (not discharged) because the operator knows the 30,000 ppm (SPP) toxicity limit cannot be met. Second, EPA does not know what complete drilling fluid composition was used in each case where we have toxicity data. Thus, EPA does not know whether a particular fluid composition that gave lower toxicity results could be used in most drilling situations. Third, EPA does not have enough information about the specifics of the drilling situation (meaning the formation geology and what part of the drilling process was occurring) corresponding to each toxicity data point. Thus, EPA does not know whether the particular fluid compositions that gave lower toxicity results represents the myriad of actual drilling situations that occur in the field. For these reasons, EPA is uncertain about why certain drilling fluids showed a toxicity less than 30,000 ppm (SPP), but, unless EPA has data about the applicability of those fluids to drilling needs across the subcategory, EPA does not believe that a more stringent limit has been shown to be available technology for BAT limits or demonstrated available technology for NSPS limits.

In response to the comment citing data used in the Environmental Assessment (1982), EPA does not believe that this data is useful for purposes of establishing an effluent limitation. At the outset, the cited data were used to demonstrate toxic effects to aquatic organisms from discharges of drilling fluids and drill cuttings rather than to set an effluent limitation. Further, all of the same problems discussed above regarding the use of monitoring data (e.g., not knowing what fluid resulted in what effluent toxicity, what geological formation was being drilled, and what phase of drilling was occurring) also applies to this data. Finally EPA cannot use this data to specify a toxicity limit because it is not possible to relate the data from many different species to a single species bioassay upon which the 30,000 ppm SPP limit is based.

The toxicity limitation is analogous to a daily maximum limitation required under this and other effluent guidelines. Such limitations include an allowance for reasonable treatment system variability that provides for variation in operating conditions expected at well-operated facilities. Operationally, ninety-ninth percentile estimates, determined through statistical analyses of performance data, are used as the basis for daily maximum limitations. The Agency believes that such limitations provide sufficient allowance for variation in normal operations. While the permit monitoring data are not the same type of data typically used to develop effluent guidelines (because we do not know what drilling fluid was used, what type of geology was encountered, and what part of the drilling process was occurring, among other things, see discussion above), the percentage of toxicity data that are more toxic than the 30,000 ppm (SPP) limit is approximately one percent no matter how the combined data from the Gulf of Mexico and Alaska Regions are analyzed. Thus, a review of these data shows that the 30,000 ppm (SPP) toxicity limit based on a product substitution approach is similar to the approach EPA generally takes in establishing maximum daily limitations.

In addition, EPA has considered that, in the absence of a reliable estimate of the number of facilities that could comply with a more stringent limitation, there would be an unknown amount of drilling fluids and drill cuttings not meeting the limitation that would need to be transported to shore.

In Alaska, transport to shore on a regular basis is not technologically achievable because of the special climate conditions that make transport from platforms to shore and ground transportation on shore infeasible during extended periods of time; in addition there is a lack of available land disposal sites. For these reasons, EPA excluded Alaska from the zero-discharge requirement applicable to drilling fluids and drill cuttings within three miles from shore.

In other regions, such a limit would increase the amount of non-water quality environmental impacts in addition to those already imposed by the three-mile zero discharge requirement for drilling fluids and drill cuttings. Any increase in the toxicity limit would have an unknown increase in the amount of air emissions and energy use from transporting drilling fluids and drill cuttings to shore, and an increase in the amount of drilling fluids and drill cuttings that would need to be disposed of in land disposal sites.

In short, because EPA does not have sufficient information to know if a more stringent toxicity limit would be feasible for drilling needs across the subcategory and because EPA does not know what effect a more stringent toxicity limit would have on non-water quality environmental impacts, in the final rule, EPA is setting the toxicity limit at 30,000 ppm (SPP), a level which EPA knows to be feasible without interfering unreasonably with drilling operations and which does not result in unacceptable non-water quality environmental impacts.

Industry comments have asserted that the EPA toxicity test is not suitable for compliance monitoring of an effluent guideline. These comments are not correct. The toxicity test for drilling fluids is suitable because the test demonstratively measures the acute toxicity for the drilling fluid and multiple tests on the same toxic substance show a spread of toxicity values about an average toxicity value. One term for the spread of values around the average toxicity value is variability. Variability for this test is estimated in Variability Study of the EPA Toxicity Test for Drilling Fluids: Statistical Analysis (1993). Given that there are variability issues associated with any measurement test, these properties of the toxicity test are allowed for in setting the effluent guidelines limitation by using the EPA toxicity test to measure the toxicity of samples from a model "system" of eight generic drilling fluids. Since precision and accuracy are inherent components of the toxicity test and are therefore inherent in the data that result from the test, these factors are entrained in the subsequent calculations performed to develop effluent limitations from those data. That adequate variability was allowed for in this procedure is demonstrated by the high percentage, greater than 90 percent of offshore wells in the Gulf of Mexico that complied with this limitation as a permit requirement in the years 1984 to 1991.

EPA also notes that the 30,000 ppm SPP toxicity limit has been imposed as a requirement in the general permits for the Outer Continental Shelf (OSC) in the Gulf of Mexico since 1986. This limit was upheld in *NRDC* v. *EPA*, 863 F.2d 1420 (9th Cir. 1988). A pre-approval system based on this limit was imposed in two general permits for the Bering and Beaufort Seas in 1984 and was upheld in *API* v. *EPA*, 787 F.2d 965 (5th Cir. 1986).

F. Static Sheen Test

Comment: Several areas addressed by the comments received on the static sheen test concerned the difficulty and expense of conducting the test, the reproducibility and accuracy of the test, and the need for such a test from the environmental benefits perspective. Commenters stated that the test method was not well established nor cost effective and results in inaccurate identifications of sheens, both false positives and negatives (i.e., when no free oil is present but is identified and when oil is present but not identified, respectively). In addition, commenters criticized the Agency for not quantifying the benefits of the test method, while others supported the method as being "scientifically superior" to the visual sheen method previously used, because unlike the static sheen test, the visual sheen test is used to detect violations after discharge.

Response: EPA disagrees with the comment that the static sheen test is not well established, expensive and not cost-effective. The static sheen test, described in appendix 1 of the final rule, is the test method used to determine compliance with the no free oil requirement, except for the no free oil requirement for deck drainage. The visual sheen test is retained to measure deck drainage compliance.

The static sheen test differs from the visual sheen test by utilizing samples of the wastes to be tested (15 milliliter or 15 gram (on a wet weight basis) quantity depending on the type of waste) introduced into a container (bucket) filled with seawater and having a specified surface area, rather than visually looking at the surface of the receiving water for the occurrence of a sheen after discharge of the waste. In the static sheen test, observations are made no more than one hour after the waste samples are added to and dispersed upon the container of seawater.

EPA believes that the static sheen test is both established and inexpensive to conduct. The test method contained in the final rule is based on the method proposed in 1985 (50 FR 34627) and has been modified to reflect the method used in the Region 10 general permits. Possible changes to the 1985 proposed method were noticed in the 1991 proposal (56 FR 10675), including the Region 10 method. The Region 10 protocol was selected based on results of assessments that demonstrate lower false positives (56 FR 10676) and its use over a ten year period with acceptable reproducibility. This protocol incorporates a larger waste sample and container of seawater and uses a more detailed description of criteria for determining whether a sheen exists or not, than the 1985 version of the test. EPA believes this is an improvement over the 1985 version; however, EPA continues to believe that the 1985 version of the test method demonstrates acceptable accuracy.

In response to comments concerning the benefits of the test, EPA believes that a test method that evaluates the potential of a sheen prior to the waste being discharged more effectively meets the intent of the CWA. The static sheen test also eliminates or reduces effects of wave action, weather conditions, and lighting (sunlight or lack of lighting) which the use of the visual sheen on the receiving waters must overcome. While EPA is not required to assess the environmental benefits of a test method, EPA notes that because the static sheen test can be used in advance of discharge to determine noncompliance, it is preferable from an environmental standpoint to a test (like the visual sheen test) that determines noncompliance only after discharge occurs.

G. Effluent Guidelines Resulting in a "Taking"

Comment: One commenter argued that EPA should assess the takings implications of these effluent guidelines pursuant to Executive Order 12630. Another commenter argued that these effluent guidelines limitations could result in a "taking."

Response: EPA believes that takings claims do not apply to effluent limitations guidelines because the issue arises only when the guidelines are applied to a particular property. In a challenge to EPA's regulations of the placer mining industry, a federal court of appeals found that a takings claim was not ripe because the guideline had not yet been applied to a particular property. *Rybachek* v. *U.S. EPA*, 904 F.2d 1276 (9th Cir. 1990).

XVII. Best Management Practices

Section 304(e) of the CWA authorizes the Administrator to prescribe "best management practices" (BMP's). EPA is not promulgating BMP's for the offshore subcategory at this time.

XVIII. 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". An upset, sometimes called an "excursion," is an unintentional noncompliance occurring for reasons beyond the reasonable control of the permittee. It has been argued that an upset provision is necessary in EPA's effluent limitations because such upsets will inevitably occur even in properly operated control equipment. Because technology based limitations require only what the technology can achieve, it is claimed that liability for such situations is improper. When confronted with this issue, courts have disagreed on whether an explicit upset exemption is necessary, or whether upset incidents may be handled through EPA's exercise of enforcement discretion. Compare *Marathon Oil Co.* v. *EPA*, 564 F.2d 1253 (9th Cir.1977), with *Weyerhaeuser* v. *Costle*, 594 F.2d 1223 (8th Cir. 1979). See also *Sierra Club* v. *Union Oil Co.*, 813 F.2d 1480 (9th Cir. 1987), *American Petroleum Institute* v. *EPA*, 540 F.2d 1023 (10th Cir. 1976), *CPC International, Inc.* v. *Train*, 540 F.2d 1320 (8th Cir. 1976), and *FMC Corp.* v. *Train*, 539 F.2d 973 (4th Cir. 1976).

A bypass is an act of intentional noncompliance during which waste treatment facilities are circumvented because of an emergency situation. EPA has in the past included bypass provisions in NPDES permits.

EPA has determined that both upset and bypass provisions should be included in NPDES permits and has promulgated permit regulations that include upset and bypass permit provisions. See 40 CFR 122.41. The upset provision establishes an upset as an affirmative defense to prosecution for violation of, among other requirements, technology-based effluent limitations. The bypass provision authorizes bypassing to prevent loss of life, personal injury, or severe property damage. Consequently, although permittees in the offshore oil and gas industry will be entitled to upset and bypass provisions in NPDES permits, this regulation does not address these issues.

XIX. 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. Variances such as 301(c) (Economic Achievability from BAT) and 301(g) (variance from BAT for specific listed non-conventional pollutants) are not applicable to BAT and BCT limitations promulgated in this rule because there are no such limitations in this rule. A section 301(n) (Fundamentally Different Factors) variance is applicable to the BAT and BCT limits in this rule.

The Fundamentally Different Factors (FDF) variance considers those facility specific factors which a permittee may consider to be uniquely different from those considered in the formulation of an effluent guideline as to make the limitations inapplicable. An FDF variance must be based only on information submitted to EPA during the rulemaking establishing the effluent limitations from which the variance is being requested, or on information the applicant did not have a reasonable opportunity to submit during the rulemaking process for these effluent limitations guidelines. If fundamentally different factors are determined, by the permitting authority (or EPA), to exist, the alternative effluent limitations for the petitioner must be no less stringent than those justified by the fundamental difference from those facilities considered in the formulation of the specific effluent limitations guideline of concern. The alternative effluent limitation, if deemed appropriate, must not result in non-water quality environmental impacts significantly greater than those accepted by EPA in the promulgation of the effluent limitations guideline. FDF variance requests with all supporting information and data must be received by the permitting authority within 180 days of publication of the final effluent limitations guideline [Publication date here]. The specific regulations covering the requirements for and the administration of FDF variances are found at 40 CFR 122.21(m)(1), and 40 CFR part 125, subpart D.

XX. Implementation of Limitations and Standards

A. Toxicity Limitation for Drilling Fluids and Drill Cuttings

The toxicity limitation would apply to any periodic blowdown of drilling fluid as well as to bulk discharges of drilling fluids and drill cuttings systems. The term "drilling fluid systems" refers to muds and additives used during the drilling of an individual exploration, development or production well. Any given well may require several types of mud due to changes in downhole conditions. As an example, a well may require use of a spud mud for the first 200 feet, a seawater-gel mud to a depth of 1,000 feet, a lightly treated lignosulfonate mud to 5,000 feet, and finally a freshwater lignosulfonate mud system to a bottom hole depth of 15,000 feet. Typically, bulk discharges of spent drilling fluids occur when mud systems are changed during drilling of or upon completion of a well.

For the purpose of self monitoring and reporting requirements in NPDES permits, it is intended that only samples of the discharged drilling fluid systems be analyzed in accordance with the bioassay method. Upon (or before) discharge a mud system should be sampled by bioassay to determine toxicity of the discharge. All discharged muds should be analyzed. Muds that are not discharged (i.e., reinjected or disposed onshore) are not subject to the toxicity limit. In the example above, four such samples and bioassays would be required because four discrete mud systems are being discharged.

For determining the toxicity of the bulk discharge of mud used at maximum well depth, samples may be obtained at any time after 80% of actual well footage (not total vertical depth) has been drilled to the end of well (100 percent vertical depth) and up to and including the time of discharge. Permit writers have the discretion to specify the appropriate point of the well depth within these parameters at which the end of well sample will be obtained. This would allow time for a sample to be collected and analyzed by bioassay and for the operator to evaluate the bioassay results so that the operator will have adequate time to plan for the final disposition of the spent drilling fluid system, e.g., if the bioassay test is failed, the operator could then anticipate and plan for transport of the spent drilling fluid system to shore in order to comply with the effluent limitation. However, the operator is not precluded from discharging a spent mud system prior to receiving analytical results. Nonetheless, the operator would be subject to compliance with the effluent limitations regardless of when self monitoring analyses are performed. The prohibition on discharges of free oil and diesel oil would apply to all discharges of drilling fluid at any time.

B. Diesel Prohibition for Drilling Fluids and Drill Cuttings

Diesel oil is prohibited from discharge from offshore oil platforms. In addition to this prohibition, drilling fluids and drill cuttings that produce a sheen or fail the toxicity limitations cannot be discharged. There is, however, the possibility that the quantity of diesel oil in the drilling fluid or drill cuttings is insufficient to produce a sheen or toxicity at a level failing the limitations. Thus, to show compliance with the diesel oil discharge prohibition, the operator is required to prove that diesel oil is not present in the discharge material. This requirement has created the need for measurement of "diesel oil".

As part of this rulemaking, EPA has developed an analytical technique capable of measuring diesel oil in drilling wastes and that would distinguish diesel oil from mineral oil, crude oil, and/or the additives that are also used in drilling fluids. Although many different techniques have been tested, there is no single analytical technique capable of unambiguously measuring diesel oil in drilling mud. In the March 13, 1991 proposal notice (56 FR 10676), EPA identified the EPA Method 1651 as adequate for use in identifying the presence of diesel oil. However, work was continued on alternative extraction and analysis techniques to simplify the operational portions of the method and enable better identification of diesel oil in the presence of interferences. As a result, EPA has developed test methods for the measurement of the hydrocarbons normally found in oil, including the polynuclear aromatic hydrocarbon (PAH) content of the oil. Combined, these techniques can be used to discern diesel oil in the presence of other components likely to be found in drilling wastes. This section gives a brief history of the efforts to develop test methods for the determination of diesel oil in drilling fluids and drill cuttings and a description of test methods that have been developed to measure and differentiate diesel oil, mineral oil, and crude oil.

In late 1990, the American Petroleum Institute (API) undertook a study of extraction and determination steps necessary to identify unambiguously diesel oil in the presence of interferences, and to overcome difficulties using Method 1651. These studies involved the evaluation of alternate extraction and determination techniques.

Extraction techniques included ultrasonic, Soxhlet/Dean-Stark, and supercritical fluid. Determinative techniques included high performance liquid chromatography with ultra-violet detection (HPLC/UV), and gas chromatography with flame ionization detection (GC/FID). One device combined extraction and determination. In this device, the drilling waste sample was placed in a small chamber and heated rapidly to desorb the oil into a flowing gas stream. The components of oil entrained in the gas stream were separated by gas chromatography, and detection by flame ionization.

Of these devices, Soxhlet/Dean-Stark extraction provided the most precise results and the results closest to true value, and HPLC/UV was found reliable for determining polynuclear aromatic hydrocarbons (PAHs) in the extract. Results of these studies are summarized in an April 1992 API Report, entitled, "Results of the API Study of Extraction and Analysis Procedures for the Determination of Diesel Oil in Drilling Muds" (the API Report). A copy of the API Report is included in the record for the rulemaking.

Based on the additional methods work resulting from comments on the proposed Method 1651, EPA is promulgating, in addition to the Method 1651, a test protocol measuring the PAH content by HPLC/UV to demonstrate that the oil is mineral oil, and will allow measurement of the normal hydrocarbon distribution by GC/FID to demonstrate that the oil is crude oil. However, EPA will not allow use of the total oil content to demonstrate that the mud is free of diesel oil.

EPA recognizes that in certain regions compliance with the diesel oil prohibition is accomplished by GC analysis of end-of-well samples. In other regions, compliance with the diesel prohibition is accomplished by review of well records maintained by platform operators to prove that diesel oil has not been added to the mud system. Both methods of determining compliance are acceptable. However, in the latter case where the enforcement agency believes that the well record is in error or has been falsified, the authority may insist that further testing be conducted to prove that diesel oil has not been used.

In this further testing for the presence of diesel oil, the drilling fluid or drill cuttings are extracted with a solvent and the amount of total extractable material is measured. If the material extracted exceeds the amount attributable to additives, the material could be diesel oil, crude oil, or mineral oil, and the next phase of testing must be conducted.

In this next phase, the PAH content of the oil in the drilling waste is determined using the HPLC/UV Method. If the PAH content is less than that attributable to mineral oil, the mud may be discharged; if greater than that attributable to mineral oil, the oil could be either diesel or crude oil. To determine whether the oil is diesel or crude, the absence of n-alkanes in the diesel range or the percent of C25—C30 alkanes using the GC/FID Method must be used to show that the oil was crude oil from the formation. If the oil was crude oil, the mud may be discharged providing it meets the other discharge limitations of the rule. Implementation of this approach employs methods contained within "Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges" (EPA 821-R-92-008).

XXI. Availability of Technical Information

The basis for this regulation is detailed in three major documents each of which in turn is supported and supplemented by additional information and analyses in the rulemaking record. EPA's technical foundation for the regulation is detailed in the "Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category" (EPA/821-R-93-003) EPA's economic analysis is presented in the "Economic Impact Analysis of Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry" (EPA/821-R-93-004) EPA's analysis of the monetized benefits of the regulation are presented in the "Regulatory Impact Analysis of the Effluent Guidelines Regulation for Offshore Oil and Gas Facilities" (EPA/821-R-93-002). Detailed responses to the public comments received on the proposed regulation and notices of data availability are presented in the document entitled "Response to Public Comments on Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category." Additional information concerning the economic impact analysis and regulatory impact analysis may be obtained from Dr. Mahesh Podar, Engineering and Analysis Division (WH-552), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460 or by calling (202) 260-5387. Technical information may be obtained from Mr. Ronald P. Jordan, Engineering and Analysis Division (WH-552), at the above address, or by calling (202) 260-7115. The public record for this rulemaking is available for review at EPA's Water Docket; 401 M Street, SW.; Washington, DC.

XXII. Office of Management and Budget (OMB) Review

This regulation and the Regulatory Impact Analysis were submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. The regulation does not contain any information collection requirements.

List of Subjects in 40 CFR Part 435

Incorporation by reference, Oil and gas exploration, Oil and gas extraction, Waste treatment and disposal, Water pollution control.

Dated: January 15, 1993.

William K. Reilly,

Administrator.

Appendix to the Preamble

Appendix A—Abbreviations, Acronyms, and Other Terms Used in this Final Rule Document

Act—Clean Water Act.
Agency—U.S. Environmental Protection Agency.
API—American Petroleum Institute.
BAT—The best available technology economically achievable, under section 304(b)(2)(B) of the Clean Water Act.
bbl—barrel, 42 U.S. gallons.
bpd—barrels per day.
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.
BPT—Best practicable control technology currently available, under section 404(b)(1) of the Clean Water Act.
Bypass—An act of intentional noncompliance during which waste treatment facilities are circumvented because of an emergency situation.
CFR—Code of Federal Regulations.
Clean Water Act—Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 *et seq.*), as amended by the Clean Water Act of 1977 (Pub. L. 95–217).
CWA—Clean Water Act.
Direct discharger—A facility which discharges or may discharge pollutants to waters of the United States.
DOE—Department of Energy.
DOE/EIA—Department of Energy, Energy Information Administration.
EIA—Economic Impact Analysis.
EPA—U.S. Environmental Protection Agency.
g—gram.
GOM—Gulf of Mexico.
kg—kilogram.
LC50—The concentration of a test material that is lethal to 50% of the test organisms in a bioassay.
mg/l—milligrams per liter.
MMS—Minerals Management Service, U.S. Department of the Interior.
NORM—Naturally Occurring Radioactive Materials.
NPDES Permit—A National Pollutant Discharge Elimination System permit issued under section 402 of the Clean Water Act.
NRDC—Natural Resources Defense Council.
NSPS—New source performance standards under section 306 of the Clean Water Act.
OCS—Outer Continental Shelf.
OOC—Offshore Operators Committee.
POTW—Publicly Owned Treatment Works.
ppm—parts per million.
Priority Pollutants—The 65 pollutants and classes of pollutants declared toxic under section 307(a) of the Clean Water Act.
RCRA—Resource Conservation and Recovery Act of 1976 (42 U.S.C. sections 6901–6992k). Amendments to Solid Waste Disposal Act.
SPP—Suspended particulate phase.
Spot—The introduction of oil to a drilling fluid system for the purpose of freeing a stuck drill bit or string.
Upset—An unintentional noncompliance occurring for reasons beyond the reasonable control of the permittee.
U.S.C.—United States Code.
USCG—U.S. Coast Guard.

For the reasons set out in the preamble, 40 CFR part 435 is amended as set forth below:

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 and 1361.

2. 40 CFR part 435, subpart A is revised to read as follows:

Subpart A—Offshore Subcategory

Subpart A—Offshore Subcategory

§ 435.10 Applicability; description of the offshore subcategory.

The provisions of this subpart are applicable to those facilities engaged in field exploration, drilling, well production, and well treatment in the oil and gas extraction industry which are located in waters that are seaward of the inner boundary of the territorial seas ("offshore") as defined in section 502(g) of the Clean Water Act. Offshore facilities that transport wastes to onshore or coastal locations for treatment and disposal offshore are subject to the regulations that are applicable to the location of where the wastes are generated or the wellhead. Wastes transported from one subcategory for subsequent discharge in another subcategory of the oil and gas extraction point source category may only be disposed of pursuant to a valid NPDES permit.

§ 435.11 Specialized definitions.

For the purpose of this subpart: (a) Except as provided in paragraphs (b) through (aa) of 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 *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.

(d) 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.

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

(f) 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 D975–81, 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.

(g) 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.

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

(i) The term *drilling fluid* shall refer to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspending medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel oil, mineral oil, or some other oil as its continuous phase with water as the dispersed phase.

(j) 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.

(k) 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.

(l) 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.

(m) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the minimum 96-hour LC50 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.

(n) 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.

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

(p)(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 ocean 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 ocean 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.

(q) The term *no discharge of free oil* shall mean that waste streams may not be discharged when they would cause a film or sheen upon or a discoloration of the surface of the receiving water or fail the static sheen test defined in Appendix 1 to 40 CFR 435, subpart A.

(r) 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.

(s) 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.

(t) 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.

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

(v) 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 435, subpart A.

(w) The term *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 435, subpart A.

(x) 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.

(y) 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.

(z) 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.

(aa) The term *96-hour LC50* 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.

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

Except as provided in 40 CFR 125.30–32, any existing point source subject to this subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available:

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
Produced water	72	48	NA
Deck drainage	(1)	(1)	NA
Drilling muds	(1)	(1)	NA
Drill cuttings	(1)	(1)	NA
Well treatment fluids	(1)	(1)	NA
Sanitary:			
M10	NA	NA	[2] 1
M9IM [3]	NA	NA	NA
Domestic	NA	NA	NA

[1] No discharge of free oil.
[2] Minimum of 1 mg/l and maintained as close to this concentration as possible.
[3] There shall be no floating solids as a result of the discharge of these wastes.

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

Except as provided in 40 CFR 125.30–32, any existing point source subject to this subpart must achieve the following effluent limitations 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
Produced water	Oil & grease.	The maximum for any one day shall not exceed 42 mg/l; the average of daily values for 30 consecutive days shall not exceed 29 mg/l.
Drilling fluids and drill cuttings:		
(A) For facilities located within 3 miles from shore.		No discharge.[1]
(B) For facilities located beyond 3 miles from shore.	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.
Well treatment, completion, and workover fluids.	Oil and grease.	The maximum for any one day shall not exceed 42 mg/l; the average of daily values for 30 consecutive days shall not exceed 29 mg/l.
Deck drainage	Free oil	No discharge.[4]
Produced sand		No discharge.
Domestic Waste	Foam	No discharge.

[1] All Alaskan facilities are subject to the drilling fluids and drill cuttings discharge limitations for facilities located beyond 3 miles offshore.

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

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

[4] As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

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

Except as provided in 40 CFR 125.30–32, any existing point source subject to this Subpart must achieve the following effluent limitations 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
Produced water	Oil & grease.	The maximum for any one day shall not exceed 72 mg/l; the average of values for 30 consecutive days shall not exceed 48 mg/l.
Drilling fluids and drill cuttings:		
(A) For facilities located within 3 miles from shore.		No discharge.[1]
(B) For facilities located beyond 3 miles from shore.	Free oil	No discharge.[2]
Well treatment, completion and workover fluids.	Free oil	No discharge.[2]
Deck drainage	Free oil	No discharge.[3]
Produced sand		No discharge.
Sanitary M10	Residual chlorine.	Minimum of 1 mg/l and maintained as close to this concentration as possible.
Sanitary M91M	Floating solids.	No discharge.
Domestic Waste	Floating solids.	No discharge.
	All other domestic waste.	See 33 CFR Part 151.

[1] All Alaskan facilities are subject to the drilling fluids and drill cuttings discharge limitations for facilities located more than 3 miles offshore.

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

[3] As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

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

Any new source subject to this subpart must achieve the following new source performance standards (NSPS):

NEW SOURCE PERFORMANCE STANDARDS

Waste source	Pollutant parameter	NSPS
Produced water	Oil and grease.	The maximum for any one day shall not exceed 42 mg/l; the average of daily values for 30 consecutive days shall not exceed 29 mg/l.
Drilling fluids and drill cuttings:		
(A) For facilities located within 3 miles from shore.		No discharge.[1]
(B) For facilities located more than 3 miles from shore.	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent 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.
Well treatment, completion, and workover fluids.	Oil and grease.	The maximum for any one day shall not exceed 42 mg/l; the average of daily values for 30 consecutive days shall not exceed 29 mg/l.
Deck drainage	Free oil	No discharge.[4]
Produced sand		No discharge.
Sanitary M10	Residual chlorine.	Minimum of 1 mg/l and maintained as close to this as possible.
Sanitary M9IM	Floating solids.	No discharge.
Domestic Waste	Floating solids.	No discharge.
	Foam	No discharge.
	All other domestic wastes.	See 33 CFR Part 151.

NEW SOURCE PERFORMANCE STANDARDS—Continued

[1] All Alaskan facilities are subject to the drilling fluids and drill cuttings discharge standards for facilities located more than three miles offshore.

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

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

[4] As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

Appendix 1 to Subpart A of Part 435—Static Sheen Test

1. Scope and Application

This method is to be used as a compliance test for the "no discharge of free oil" requirement for discharges of drilling fluids, drill cuttings, produced sand, and well treatment, completion and workover fluids. "Free oil" refers to any oil contained in a waste stream that when discharged will cause a film or sheen upon or a discoloration of the surface of the receiving water.

2. Summary of Method

15-mL samples of drilling fluids or well treatment, completion, and workover fluids, and 15-g samples (wet weight basis) of drill cuttings or produced sand are introduced into ambient seawater in a container having an air-to-liquid interface area of 1000 cm^2 (155.5 in^2). Samples are dispersed within the container and observations made no more than one hour later to ascertain if these materials cause a sheen, iridescence, gloss, or increased reflectance on the surface of the test seawater. The occurrence of any of these visual observations will constitute a demonstration that the tested material contains "free oil," and therefore results in a prohibition of its discharge into receiving waters.

3. Interferences

Residual "free oil" adhering to sampling containers, the magnetic stirring bar used to mix the sample, and the stainless steel spatula used to mix the sample will be the principal sources of contamination problems. These problems should only occur if improperly washed and cleaned equipment are used for the test. The use of disposable equipment minimizes the potential for similar contamination from pipettes and the test container.

4. Apparatus, Materials, and Reagents

4.1 Apparatus

4.1.1 Sampling Containers: 1-liter polyethylene beakers and 1-liter glass beakers.

4.1.2 Graduated cylinder: 100-mL graduated cylinder required only for operations where predilution of mud discharges is required.

4.1.3 Plastic disposable weighing boats.

4.1.4 Triple-beam scale.

4.1.5 Disposable pipettes: 25-mL disposable pipettes.

4.1.6 Magnetic stirrer and stirring bar.

4.1.7 Stainless steel spatula.

4.1.8 Test container: Open plastic container whose internal cross-section parallel to its opening has an area of 1000 cm^2±50 cm^2 (155.5 ±7.75 in^2), and a depth of at least 13 cm (5 inches) and no more than 30 cm (11.8 inches).

4.2 Materials and Reagents.

4.2.1 Plastic liners for the test container: Oil-free, heavy-duty plastic trash can liners that do not inhibit the spreading of an oil film. Liners must be of sufficient size to completely cover the interior surface of the test container. Permittees must determine an appropriate local source of liners that do not inhibit the spreading of 0.05 mL of diesel fuel added to the lined test container under the test conditions and protocol described below.

4.2.2 Ambient receiving water.

5. Calibration

None currently specified.

6. Quality Control Procedures

None currently specified.

7. Sample Collection and Handling

7.1 Sampling containers must be thoroughly washed with detergent, rinsed a minimum of three times with fresh water, and allowed to air dry before samples are collected.

7.2 Samples of drilling fluid to be tested shall be taken at the shale shaker after cuttings have been removed. The sample volume should range between 200 mL and 500 mL.

7.3 Samples of drill cuttings will be taken from the shale shaker screens with a clean spatula or similar instrument and placed in a glass beaker. Cuttings samples shall be collected prior to the addition of any washdown water and should range between 200 g and 500 g.

7.4 Samples of produced sand must be obtained from the solids control equipment from which the discharge occurs on any given day and shall be collected prior to the addition of any washdown water; samples should range between 200 g and 500 g.

7.5 Samples of well treatment, completion, and workover fluids must be obtained from the holding facility prior to discharge; the sample volume should range between 200 mL and 500 mL.

7.6 Samples must be tested no later than 1 hour after collection.

7.7 Drilling fluid samples must be mixed in their sampling containers for 5 minutes prior to the test using a magnetic bar stirrer. If predilution is imposed as a permit condition, the sample must be mixed at the same ratio with the same prediluting water as the discharged muds and stirred for 5 minutes.

7.8 Drill cuttings must be stirred and well mixed by hand in their sampling containers prior to testing, using a stainless steel spatula.

8. Procedure

8.1 Ambient receiving water must be used as the "receiving water" in the test. The temperature of the test water shall be as close as practicable to the ambient conditions in the receiving water, not the room temperature of the observation facility. The test container must have an air-to-liquid interface area of 1000 ±50 cm^2. The surface of the water should be no more than 1.27 cm (.5 inch) below the top of the test container.

8.2 Plastic liners shall be used, one per test container, and discarded afterwards. Some liners may inhibit spreading of added oil; operators shall determine an appropriate local source of liners that do not inhibit the spreading of the oil film.

8.3 A 15-mL sample of drilling fluid or well treatment, completion, and workover fluids must be introduced by pipette into the test container 1 cm below the water surface. Pipettes must be filled and discharged with test material prior to the transfer of test material and its introduction into test containers. The test water/test material mixture must be stirred using the pipette to distribute the test material homogeneously throughout the test water. The pipette must be used only once for a test and then discarded.

8.4 Drill cuttings or produced sand should be weighed on plastic weighing boats; 15-g samples must be transferred by scraping test material into the test water with a stainless steel spatula. Drill cuttings shall not be prediluted prior to testing. Also, drilling fluids and cuttings will be tested separately. The weighing boat must be immersed in the test water and scraped with the spatula to transfer any residual material to the test container. The drill cuttings or produced sand must be stirred with the spatula to an even distribution of solids on the bottom of the test container.

8.5 Observations must be made no later than 1 hour after the test material is transferred to the test container. Viewing points above the test container should be made from at least three sides of the test container, at viewing angles of approximately 60° and 30° from the horizontal. Illumination of the test container must be representative of adequate lighting for a working environment to conduct routine laboratory procedures. It is recommended that the water surface of the test container be observed under a fluorescent light source such as a dissecting microscope light. The light source shall be positioned above and directed over the entire surface of the pan.

8.6 Detection of a "silvery" or "metallic" sheen or gloss, increased reflectivity, visual color, iridescence, or an oil slick on the water surface of the test container surface shall constitute a demonstration of "free oil." These visual observations include patches, streaks, or sheets of such altered surface characteristics. If the free oil content of the sample approaches or exceeds 10%, the water surface of the test container may lack color, a sheen, or iridescence, due to the increased thickness of the film; thus, the observation for an oil slick is required. The surface of the test container shall not be disturbed in any manner that reduces the size of any sheen or slick that may be present.

If an oil sheen or slick occurs on less than one-half of the surface area after the sample is introduced to the test container, observations will continue for up to 1 hour. If the sheen or slick increases in size and covers greater than one-half of the surface area of the test container during the observation period, the discharge of the material shall cease. If the sheen or slick does not increase in size to cover greater than one-half of the test container surface area after one hour of observation, discharge may continue and additional sampling is not required.

If a sheen or slick occurs on greater than one-half of the surface area of the test container after the test material is introduced, discharge of the tested material shall cease. The permittee may retest the material causing the sheen or slick. If subsequent tests do not result in a sheen or slick covering greater than one-half of the surface area of the test container, discharge may continue.

Appendix 2 to Subpart A of Part 435—Drilling Fluids Toxicity Test

I. Sample Collection

The collection and preservation methods for drilling fluids (muds) and water samples presented here are designed to minimize sample contamination and alteration of the physical or chemical properties of the samples due to freezing, air oxidation, or drying.

I–A Apparatus

(1) The following items are required for water and drilling mud sampling and storage:

a. Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating drilling mud sampler.

b. Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating water sampler.

c. Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminated vessels for water and mud samples.

d. Ice chests for preservation and shipping of mud and water samples.

I-B. Water Sampling

(1) Collection of water samples shall be made with appropriate acid-rinsed linear-polyethylene bottles or other appropriate non-contaminating water sampling devices. Special care shall be taken to avoid the introduction of contaminants from the sampling devices and containers. Prior to use, the sampling devices and containers should be thoroughly cleaned with a detergent solution, rinsed with tap water, soaked in 10 percent hydrochloric acid (HCl) for 4 hours, and then thoroughly rinsed with glass-distilled water.

I-C. Drilling Mud Sampling

(1) Drilling mud formulations to be tested shall be collected from active field systems. Obtain a well-mixed sample from beneath the shale shaker after the mud has passed through the screens. Samples shall be stored in polyethylene containers or in other appropriate uncontaminated vessels. Prior to sealing the sample containers on the platform, flush as much air out of the container by filling it with drilling fluid sample, leaving a one inch space at the top.

(2) Mud samples shall be immediately shipped to the testing facility on blue or wet ice (do not use dry ice) and continuously maintained at 0–4° C until the time of testing.

(3) Bulk mud samples shall be thoroughly mixed in the laboratory using a 1000 rpm high shear mixer and then subdivided into individual, small wide-mouthed (e.g., one or two liter) non-contaminating containers for storage.

(4) The drilling muds stored in the laboratory shall have any excess air removed by flushing the storage containers with nitrogen under pressure anytime the containers are opened. Moreover, the sample in any container opened for testing must be thoroughly stirred using a 1000 rpm high shear mixer prior to use.

(5) Most drilling mud samples may be stored for periods of time longer than 2 weeks prior to toxicity testing provided that proper containers are used and proper condition are maintained.

II. Suspended Particulate Phase Sample Preparation

(1) Mud samples that have been stored under specified conditions in this protocol shall be prepared for tests within three months after collection. The SPP shall be prepared as detailed below.

II--A Apparatus

(1) The following items are required:

a. Magnetic stir plates and bars.

b. Several graduated cylinders, ranging in volume from 10 mL to 1 L

c. Large (15 cm) powder funnels.

d. Several 2-liter graduated cylinders.

e. Several 2-liter large mouth graduated Erlenmeyer flasks.

(2) Prior to use, all glassware shall be thoroughly cleaned. Wash all glassware with detergent, rinse five times with tap water, rinse once with acetone, rinse several times with distilled or deionized water, place in a clean 10-percent (or stronger) HCl acid bath for a minimum of 4 hours, rinse five times with tap water, and then rinse five times with distilled or deionized water. For test samples containing mineral oil or diesel oil, glassware should be washed with petroleum ether to assure removal of all residual oil.

Note: If the glassware with nytex cups soaks in the acid solution longer than 24 hours, then an equally long deionized water soak should be performed.

II-B Test Seawater Sample Preparation

(1) Diluent seawater and exposure seawater samples are prepared by filtration through a 1.0 micrometer filter prior to analysis.

(2) Artificial seawater may be used as long as the seawater has been prepared by standard methods or ASTM methods, has been properly "seasoned," filtered, and has been diluted with distilled water to the same specified 20±2 ppt salinity and 20±2° C temperature as the "natural" seawater.

II-C Sample Preparation

(1) The pH of the mud shall be tested prior to its use. If the pH is less than 9, if black spots have appeared on the walls of the sample container, or if the mud sample has a foul odor, that sample shall be discarded. Subsample a manageable aliquot of mud from the well-mixed original sample. Mix the mud and filtered test seawater in a volumetric mud-to-water ratio of 1 to 9. This is best done by the method of volumetric displacement in a 2–L, large mouth, graduated Erlenmeyer flask. Place 1000 mL of seawater into the graduated Erlenmeyer flask. The mud subsample is then carefully added via a powder funnel to obtain a total volume of 1200 mL. (A 200 mL volume of the mud will now be in the flask).

The 2–L, large mouth, graduated Erlenmeyer flask is then filled to the 2000 mL mark with 800 mL of seawater, which produces a slurry with a final ratio of one volume drilling mud to nine volumes water. If the volume of SPP required for testing or analysis exceeds 1500 to 1600 mL, the initial volumes should be proportionately increased. Alternatively, several 2–L drill mud/water slurries may be prepared as outlined above and combined to provide sufficient SPP.

(2) Mix this mud/water slurry with magnetic stirrers for 5 minutes. Measure the pH and, if necessary, adjust (decrease) the pH of the slurry to within 0.2 units of the seawater by adding 6N HCl while stirring the slurry. Then, allow the slurry to settle for 1 hour. Record the amount of HCl added.

(3) At the end of the settling period, carefully decant (do not siphon) the Suspended Particulate Phase (SPP) into an appropriate container. Decanting the SPP is one continuous action. In some cases no clear interface will be present; that is, there will be no solid phase that has settled to the bottom. For those samples the entire SPP solution should be used when preparing test concentrations. However, in those cases when no clear interface is present, the sample must be remixed for five minutes. This insures the homogeneity of the mixture prior to the preparation of the test concentrations. In other cases, there will be samples with two or more phases, including a solid phase. For those samples, carefully and continuously decant the supernatant until the solid phase on the bottom of the flask is reached. The decanted solution is defined to be 100 percent SPP. Any other concentration of SPP refers to a percentage of SPP that is obtained by volumetrically mixing 100 percent SPP with seawater.

(4) SPP samples to be used in toxicity tests shall be mixed for 5 minutes and must not be preserved or stored.

(5) Measure the filterable and unfilterable residue of each SPP prepared for testing. Measure the dissolved oxygen (DO) and pH of the SPP. If the DO is less than 4.9 ppm, aerate the SPP to at least 4.9 ppm which is 65 percent of saturation. Maximum allowable aeration time is 5 minutes using a generic commercial air pump and air stone. Neutralize the pH of the SPP to a pH 7.8±.1 using a dilute HCl solution. If too much acid is added to lower the pH saturated NaOH may be used to raise the pH to 7.8±.1 units. Record the amount of acid or NaOH needed to lower/raise to the appropriate pH. Three repeated DO and pH measurements are needed to insure homogeneity and stability of the SPP. Preparation of test concentrations may begin after this step is complete.

(6) Add the appropriate volume of 100 percent SPP to the appropriate volume of seawater to obtain the desired SPP concentration. The control is seawater only. Mix all concentrations and the control for 5 minutes by using magnetic stirrers. Record the time; and, measure DO and pH for Day 0. Then, the animals shall be randomly selected and placed in the dishes in order to begin the 96-hour toxicity test.

III. Guidance for Performing Suspended Particulate Phase Toxicity Tests Using Mysidopsis bahia

III-A Apparatus

(1) Items listed by Borthwick [1] are required for each test series, which consists of one set of control and test containers, with three replicates of each.

III-B Sample Collection Preservation

(1) Drilling muds and water samples are collected and stored, and the suspended particulate phase prepared as described in Section 1–C.

III-C Species Selection

(1) The Suspended Particulate Phase (SPP) tests on drilling muds shall utilize the test species *Mysidopsis bahia*. Test animals shall be 3 to 6 days old on the first day of exposure. Whatever the source of the animals, collection and handling should be as gentle as possible. Transportation to the laboratory should be in well-aerated water from the animal culture site at the temperature and salinity from which they were cultured. Methods for handling, acclimating, and sizing bioassay organisms given by Borthwick [1] and Nimmo [2] shall be followed in matters for which no guidance is given here.

III-D Experimental Conditions

(1) Suspended particulate phase (SPP) tests should be conducted at a salinity of 20±2 ppt. Experimental temperature should be 20±2°C.

Dissolved oxygen in the SPP shall be raised to or maintained above 65 percent of saturation prior to preparation of the test concentrations. Under these conditions of temperature and salinity, 65 percent saturation is a DO of 5.3 ppm. Beginning at Day 0-before the animals are placed in the test containers DO, temperature, salinity, and pH shall be measured every 24 hours. DO should be reported in milligrams per liter.

(2) Aeration of test media is required during the entire test with a rate estimated to be 50–140 cubic centimeters/minute. This air flow to each test dish may be achieved through polyethylene tubing (0.045-inch inner diameter and 0.062-inch outer diameter) by a small generic aquarium pump. The delivery method, surface area of the aeration stone, and flow characteristics shall be documented. All treatments, including control, shall be the same.

(3) Light intensity shall be 1200 microwatts/cm^2 using cool white fluorescent bulbs with a 14-hr light and 10-hr dark cycle. This light/dark cycle shall also be maintained during the acclimation period and the test.

III–E Experimental Procedure

(1) Wash all glassware with detergent, rinse five times with tap water, rinse once with acetone, rinse several times with distilled or deionized water, place in a clean 10 percent HCl acid bath for a minimum of 4 hours, rinse five times with tap water, and then rinse five times with distilled water.

(2) Establish the definitive test concentration based on results of a range finding test. A minimum of five test concentrations plus a negative and positive (reference toxicant) control is required for the definitive test. To estimate the LC–50, two concentrations shall be chosen that give (other than zero and 100 percent) mortality above and below 50 percent.

(3) Twenty organisms are exposed in each test dish. Nytex® cups shall be inserted into every test dish prior to adding the animals. These "nylon mesh screen" nytex holding cups are fabricated by gluing a collar of 363-micrometer mesh nylon screen to a 15-centimeter wide Petri dish with silicone sealant. The nylon screen collar is approximately 5 centimeters high. The animals are then placed into the test concentration within the confines of the Nytex cups.

(4) Individual organisms shall be randomly assigned to treatment. A randomization procedure is presented in Section V of this protocol. Make every attempt to expose animals of approximately equal size. The technique described by Borthwick [1], or other suitable substitutes, should be used for transferring specimens. Throughout the test period, mysids shall be fed daily with approximately 50 *Artemia* (brine shrimp) nauplii per mysid. This will reduce stress and decrease cannibalism.

(5) Cover the dishes, aerate, and incubate the test containers in an appropriate test chamber. Positioning of the test containers holding various concentrations of test solution should be randomized if incubator arrangement indicates potential position difference. The test medium is not replaced during the 96-hour test.

(6) Observations may be attempted at 4, 6 and 8 hours; they must be attempted at 0, 24, 48, and 72 hours and must be made at 96 hours. Attempts at observations refers to placing a test dish on a light table and visually counting the animals. Do not lift the "nylon mesh screen" cup out of the test dish to make the observation. No unnecessary handling of the animals should occur during the 96 hour test period. DO and pH measurements must also be made at 0, 24, 48, 72, and 96 hours. Take and replace the test medium necessary for the DO and pH measurements outside of the nytex cups to minimize stresses on the animals.

(7) At the end of 96 hours, all live animals must be counted. Death is the end point, so the number of living organisms is recorded. Death is determined by lack of spontaneous movement. All crustaceans molt at regular intervals, shedding a complete exoskeleton. Care should be taken not to count an exoskeleton. Dead animals might decompose or be eaten between observations. Therefore, always count living, not dead animals. If daily observations are made, remove dead organisms and molted exoskeletons with a pipette or forceps. Care must be taken not to disturb living organisms and to minimize the amount of liquid withdrawn.

IV. Methods for Positive Control Tests (Reference Toxicant)

(1) Sodium lauryl sulfate (dodecyl sodium sulfate) is used as a reference toxicant for the positive control. The chemical used should be approximately 95 percent pure. The source, lot number, and percent purity shall be reported.

(2) Test methods are those used for the drilling fluid tests, except that the test material was prepared by weighing one gram sodium lauryl sulfate on an analytical balance, adding the chemical to a 100-milliliter volumetric flask, and bringing the flask to volume with deionized water. After mixing this stock solution, the test mixtures are prepared by adding 0.1 milliliter of the stock solution for each part per million desired to one liter of seawater.

(3) The mixtures are stirred briefly, water quality is measured, animals are added to holding cups, and the test begins. Incubation and monitoring procedures are the same as those for the drilling fluids.

V. Randomization Procedure

V–A Purpose and Procedure

(1) The purpose of this procedure is to assure that mysids are impartially selected and randomly assigned to six test treatments (five drilling fluid or reference toxicant concentrations and a control) and impartially counted at the end of the 96-hour test. Thus, each test setup, as specified in the randomization procedure, consists of 3 replicates of 20 animals for each of the six treatments, i.e., 360 animals per test. Figure 1 is a flow diagram that depicts the procedure schematically and should be reviewed to understand the over-all operation. The following tasks shall be performed in the order listed.

(2) Mysids are cultured in the laboratory in appropriate units. If mysids are purchased, go to Task 3.

(3) Remove mysids from culture tanks (6, 5, 4, and 3 days before the test will begin, i.e. Tuesday, Wednesday, Thursday, and Friday if the test will begin on Monday) and place them in suitably large maintenance containers so that they can swim about freely and be fed.

Note: Not every detail (the definition of suitably large containers, for example) is provided here. Training and experience in aquatic animal culture and testing will be required to successfully complete these tests.

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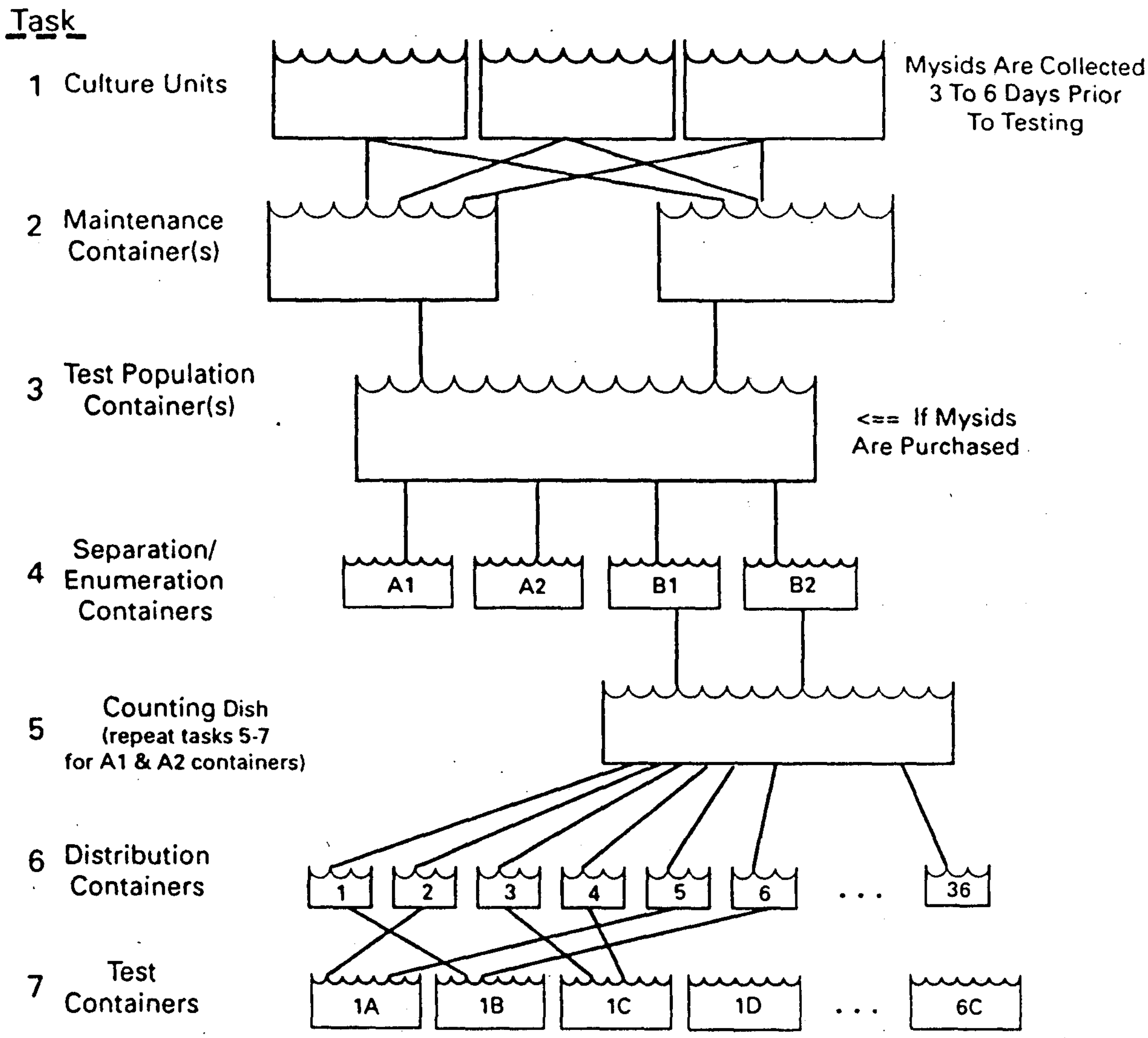
Figure 1
Mysid Randomization Procedure



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(4) Remove mysids from maintenance containers and place all animals in a single container. The intent is to have homogeneous test population of mysids of a known age (3–6 days old).

(5) For each toxicity test, assign two suitable containers (500-milliliter (mL) beakers are recommended) for mysid separation/enumeration. Label each container (A1, A2, B1, B2, and C1, C2, for example, if two drilling fluid tests and a reference toxicant test are to be set up on one day). The purpose of this task is to allow the investigator to obtain a close estimate of the number of animals available for testing and to prevent unnecessary crowding of the mysids while they are being counted and assigned to test containers. Transfer the mysids from the large test population container to the labeled separation and enumeration containers but do not place more than 200 mysids in a 500-mL beaker. Be impartial in transferring the mysids; place approximately equal numbers of animals (10–15 mysids is convenient) in each container in a cyclic manner rather than placing the maximum number each container at one time.

Note: It is important that the animals not be unduly stressed during this selection and assignment procedure. Therefore, it will probably be necessary to place all animals (except the batch immediately being assigned to test containers) in mesh cups with flowing seawater or in large volume containers with aeration. The idea is to provide the animals with near optimal conditions to avoid additional stress.

(6) Place the mysids from the two labeled enumeration containers assigned to a specific test into one or more suitable containers to be used as counting dishes (2-liter Carolina dishes are suggested). Because of the time required to separate, count, and assign mysids, two or more people may be involved in completing this task. If this is done, two or more counting dishes may be used, but the investigator must make sure that approximately equal numbers of mysids from each labeled container are placed in each counting dish.

(7) By using a large-bore, smooth-tip glass pipette, select mysids from the counting dish(es) and place them in the 36 individually numbered distribution containers (10-ml beakers are suggested). The mysids are assigned two at a time to the 36 containers by using a randomization schedule similar to the one presented below. At the end of selection/assignment round 1, each container will contain two mysids; at the end of round 2, they will contain four mysids; and so on until each contains ten mysids.

EXAMPLE OF A RANDOMIZATION SCHEDULE

Selection/assignment round (2 mysids each)	Place mysid in the numbered distribution containers in the random order shown
1	8, 21, 6, 28, 33, 32, 1, 3, 10, 9, 4, 14, 23, 2, 34, 22, 36, 27, 5, 30, 35, 24, 12, 25, 11, 17, 19, 26, 31, 7, 20, 15, 18, 13, 16, 29.
2	35, 18, 5, 12, 32, 34, 22, 3, 9, 16, 26, 13, 20, 28, 6, 21, 24, 30, 8, 31, 7, 23, 2, 15, 25, 17, 1, 11, 27, 4, 19, 36, 10, 33, 14, 29.
3	7, 19, 14, 11, 34, 21, 25, 27, 17, 18, 6, 16, 29, 2, 32, 10, 4, 20, 3, 9, 1, 5, 28, 24, 31, 15, 22, 13, 33, 26, 36, 12, 8, 30, 35, 23.
4	30, 2, 18, 5, 8, 27, 10, 25, 4, 20, 26, 15, 31, 36, 35, 23, 11, 29, 16, 17, 28, 1, 33, 14, 9, 34, 7, 3, 12, 22, 21, 6, 19, 24, 32, 13.
5	34, 28, 16, 17, 10, 12, 1, 36, 20, 18, 15, 22, 2, 4, 19, 23, 27, 29, 25, 21, 30, 3, 9, 33, 32, 6, 14, 11, 35, 24, 26, 7, 31, 5, 13, 8.

(8) Transfer mysids from the 36 distribution containers to 18 labeled test containers in random order. A label is assigned to each of the three replicates (A, B, C) of the six test concentrations. Count and record the 96 hour response in an impartial order.

(9) Repeat tasks 5–7 for each toxicity test. A new random schedule should be followed in Tasks 6 and 7 for each test.

Note: If a partial toxicity test is conducted, the procedures described above are appropriate and should be used to prepare the single test concentration and control, along with the reference toxicant test.

V–B. Data Analysis and Interpretation

(1) Complete survival data in all test containers at each observation time shall be presented in tabular form. If greater than 10 percent mortality occurs in the controls, all data shall be discarded and the experiment repeated. Unacceptably high control mortality indicates the presence of important stresses on the organisms other than the material being tested, such as injury or disease, stressful physical or chemical conditions in the containers, or improper handling, acclimation, or feeding. If 10 percent mortality or less occurs in the controls, the data may be evaluated and reported.

(2) A definitive, full bioassay conducted according to the EPA protocol is used to estimate the concentration that is lethal to 50 percent of the test organisms that do not die naturally. This toxicity measure is known as the median lethal concentration, or LC–50. The LC–50 is adjusted for natural mortality or natural responsiveness. The maximum likelihood estimation procedure with the adjustments for natural responsiveness as given by D.J. Finney, in *Probit Analysis* 3rd edition, 1971, Cambridge University Press, Chapter 7, can be used to obtain the probit model estimate of the LC–50 and the 95 percent fiducial (confidence) limits for the LC–50. These estimates are obtained using the logarithmic transform of the concentration. The heterogeneity factor (Finney 1971, pages 70–72) is not used. For a test material to pass the toxicity test, according to the requirements stated in the offshore oil and gas extraction industry BAT effluent limitations and NSPS, the LC–50, adjusted for natural responsiveness, must be greater than 3 percent suspended particulate phase (SPP) concentration by volume unadjusted for the 1 to 9 dilution. Other toxicity test models may be used to obtain toxicity estimates provided the modeled mathematical expression for the lethality rate must increase continuously with concentration. The lethality rate is modeled to increase with concentration to reflect an assumed increase in toxicity with concentration even though the observed lethality may not increase uniformly because of the unpredictable animal response fluctuations.

(3) The range finding test is used to establish a reasonable set of test concentrations in order to run the definitive test. However, if the lethality rate changes rapidly over a narrow range of concentrations, the range finding assay may be too coarse to establish an adequate set of test concentrations for a definitive test.

(4) The EPA Environmental Research Laboratory in Gulf Breeze, Florida prepared a Research and Development Report entitled Acute Toxicity of Eight Drilling Fluids to Mysid Shrimp (*Mysidopsis bahia*), May 1984 EPA–600/3–84–067. The Gulf Breeze data for drilling fluid number 1 are displayed in Table 1 for purposes of an example of the probit analysis described above. The SAS Probit Procedure (SAS Institute, Statistical Analysis System, Cary, North Carolina, 1982) was used to analyze these data. The 96-hour LC50 adjusted for the estimated spontaneous mortality rate is 3.3 percent SPP with 95 percent limits of 3.0 and 3.5 percent SPP with the 1 to 9 dilution. The estimated spontaneous mortality rate based on all of the data is 9.6 percent.

TABLE 1.—LISTING OF ACUTE TOXICITY TEST DATA (AUGUST 1983 TO SEPTEMBER 1983) WITH EIGHT GENERIC DRILLING FLUIDS AND MYSID SHRIMP

[fluid N2=1]

Percent concentration	Number exposed	Number dead (96 hours)	Number alive (96 hours)
0	60	3	57
1	60	11	49
2	60	11	49
3	60	25	35
4	60	48	12
5	60	60	0

V-C. The Partial Toxicity Test for Evaluation of Test Material

(1) A partial test conducted according to EPA protocol can be used economically to demonstrate that a test material passes the toxicity test. The partial test cannot be used to estimate the LC-50 adjusted for natural response.

(2) To conduct a partial test follow the test protocol for preparation of the test material and organisms. Prepare the control (zero concentration), one test concentration (3 percent suspended particulate phase) and the reference toxicant according to the methods of the full test. A range finding test is not used for the partial test.

(3) Sixty test organisms are used for each test concentration. Find the number of test organisms killed in the control (zero percent SPP) concentration in the column labeled X_0 of Table 2. If the number of organisms in the control (zero percent SPP) exceeds the table values, then the test is unacceptable and must be repeated. If the number of organisms killed in the 3 percent test concentration is less than or equal to corresponding number in the column labeled X_1 then the test material passes the partial toxicity test. Otherwise the test material fails the toxicity test.

(4) Data shall be reported as percent suspended particulate phase.

TABLE 2

X_0	X_1
0	22
1	22
2	23
3	23
4	24
5	24
6	25

VI. References

1. Borthwick, Patrick W. 1978. Methods for acute static toxicity tests with mysid shrimp (*Mysidopsis bahia*). Bioassay Procedures for the Ocean Disposal Permit Program, [EPA-600/9-78-010:] March.

2. Nimmo, D.R., T.L. Hamaker, and C.A. Somers. 1978. Culturing the mysid (*Mysidopsis bahia*) in flowing seawater or a static system. Bioassay Procedures for the Ocean Disposal Permit Program, [EPA-600/9-78-010]: March.

3. American Public Health Association et al. 1980. Standard Methods for the Examination of Water and Wastewater. Washington, D.C. 15th Edition: 90-99.

4. U.S. Environmental Protection Agency, September 1991. Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters to Freshwater and Marine Organisms EPA/600/4-90/027. Washington, D.C. 4th Edition.

5. Finney, D.J. Probit Analysis. Cambridge University Press; 1971.

6. U.S. Environmental Protection Agency, May 1984. Acute Toxicity of Eight Drilling Fluids to Mysid Shrimp (*Mysidopsis bahia*). EPA-600/3-84-067.

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