ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 435

[FRL-3898-4]

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: Proposed rule.

SUMMARY: EPA is proposing regulations under the Clean Water Act to limit effluent discharges to waters of the United States from offshore oil and gas extraction facilities. The purpose of this proposal is to establish new source performance standards (NSPS), best available technology economically achievable (BAT), and best conventional pollutant control technology (BCT) effluent limitations guidelines for the offshore subcategory of the oil and gas extraction point source category.

On November 26, 1990, EPA published an initial proposal and reproposal that presented the major regulatory options that the Agency is considering for control of drilling fluids, drill cuttings, produced water, deck drainage, produced sand, well treatment/workover fluids, and domestic and sanitary wastes. Today's notice describes the proposal in greater detail and sets forth additional technical, economic, environmental, and other information relating to the establishment of effluent guidelines and standards for the offshore subcategory. After considering comments received in response to today's proposal and the November 26 proposal, EPA will promulgate a final rule.

The Agency will schedule two public workshops to explain the proposed regulation. The Agency is inviting state and EPA permit writers, industry representatives and members of the general public to attend and participate in these workshops. For information on the dates and locations of the workshops see the **ADDRESSES** section of today's notice.

DATES: Comments must be received on or before April 12, 1991.

ADDRESSES: Comments should be sent to Mr. Marvin B. Rubin, Office of Water, Industrial Technology Division (WH-552), Environmental Protection Agency, 401 M Street SW., Washington, DC 20460, (202) 382-7124.

The supporting information and all comments on this proposal will be available for inspection and copying at the EPA Public Information Reference Unit, room M2904 (Rear of EPA Headquarters Library), 401 M Street SW., Washington, DC, 9 a.m. to 4 p.m., Monday through Friday, excluding Federal holidays. The EPA public information regulation (40 CFR part 2) provides that a reasonable fee may be charged for copying. Technical information on workshops and copies of technical documents may be obtained from Mr. Marvin B. Rubin at the above address. The economic analysis report may be obtained from Ms. Ann Watkins, Economic Analysis Staff (WH-586), at the above address, or call (202) 382-5387. The Regulatory Impact Analysis (RIA) may be obtained from Ms. Alexandra Tarnay, Assessment and Watershed Protection Division (WH-553), at the above address, or call (202) 382-7046.

FOR FURTHER INFORMATION CONTACT: Mr. Marvin B. Rubin at the above address, or call (202) 382-7124.

SUPPLEMENTARY INFORMATION:

Organization of Today's Notice

I. Introduction

The purpose of this rulemaking is to propose standards of performance for new sources and effluent limitations guidelines for existing sources under sections 301, 304, 306, 307, and 501 of the Clean Water Act for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category. These regulations are also proposed in response to a Settlement Agreement approved on April 5, 1990 in *NRDC* v. *Reilly*, D.D.C. No. 79-3442 (JHP) and in accordance with EPA's Effluent Guidelines Plan under section 304(m) of the Clean Water Act (55 FR 80) (January 2, 1990).

The proposed regulations would apply 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 Clean Water Act 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." 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; requires a minimum residual chlorine content of 1 mg/l in sanitary discharges; and prohibits the discharge of floating solids in sanitary and domestic wastes. BPT limitations are not being changed by this proposal.

This rulemaking will establish 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 rulemaking also proposes requirements based on best conventional pollutant control technology (BCT). In addition, this rulemaking proposes new source performance standards (NSPS) based on the best demonstrated control technology.

On August 26, 1985, EPA proposed BAT, BCT, and NSPS for the offshore oil and gas industry (50 FR 34592). This proposal being issued today does not supersede the 1985 proposal entirely but, rather, changes the proposal in certain areas. Some items proposed in 1985 remain unchanged. In today's notice, EPA highlights the differences and similarities between today's proposal and the 1985 proposal.

Much data and information have been 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 was published in a Notice of Data Availability (53 FR 41356) (October 21, 1988). This new information has led EPA to develop additional regulatory options different from those proposed in 1985.

On November 26, 1990 the Agency published an initial proposal and 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. The options presented in that proposal are identical to those presented today, with the exception that the November 26 proposal stated that NSPS for sanitary wastes includes a prohibition on the discharge of visible foam.

For this rulemaking, EPA is proposing BAT and NSPS effluent limitations for produced waters equal to BPT for structures located more than 4 miles from the inner boundary of the territorial seas (shore). For structures located 4 miles or less from shore, EPA is proposing produced water effluent limitations for oil and grease based on membrane filtration as an add-on technology to BPT. The limitations are 7 mg/l monthly average and 13 mg/l daily maximum not to be exceeded. For drilling fluids and drill cuttings, wells located more than 4 miles from shore are subject to effluent limitations for toxicity of 30,000 ppm (SPP basis), cadmium and mercury of 1 mg/kg each in drilling fluids and drill cuttings discharges, as well as a requirement for no discharge of diesel oil and free oil. For wells located 4 miles or less from shore, zero discharge of drilling fluids and drill cuttings is being proposed. An exception to the limitations on drilling fluids and cuttings is being proposed for Alaska and is discussed later in section XII.

BAT and NSPS are also being proposed for deck drainage; produced sand; treatment, completion, and workover fluids; and domestic and sanitary wastes. These are collectively referred to as the miscellaneous waste streams. Zero discharge is being proposed for the produced sand (solids) waste stream. Zero discharge of treatment, completion, and workover fluids is being proposed when they resurface as a discrete slug. Otherwise, if these fluids do not surface as a discrete unit, then they would be commingled with and treated along with produced waters. The Agency is proposing that deck drainage be subject to the same limitations as produced water during the production phase of the oil and gas extraction operation. During the exploration and development phases, deck drainage will be subject to the BPT limits prohibiting discharge of free oil. The Agency is not proposing BAT for domestic and sanitary wastes because there have been no toxic or nonconventional pollutants of concern identified in these wastes. NSPS for sanitary wastes is being proposed as equal to BPT. NSPS for domestic wastes is proposed as equal to current permit requirements prohibiting discharge of floating solids, plus the additional requirement for no visible discharge of foam.

BCT for produced waters is being proposed equal to BPT. BCT for drilling fluids and drill cuttings is being proposed equal to the zero discharge for structures located 4 miles or less from shore and BPT for structures greater than 4 miles from shore. The proposed BCT requirement for well treatment, completion, and workover fluids; deck drainage and produced sand is no discharge of free oil; for sanitary wastes BCT limitations are proposed controlling residual chlorine at facilities with ten or more personnel and no discharge of floating solids for both sanitary wastes at facilities with less than nine personnel and for domestic wastes.

The Agency is collecting additional data concerning membranes which will be noticed for public comment between today's proposal and final rulemaking. In addition, the Agency solicits comment on this topic as part of this proposed rulemaking (see section XIX of today's notice). Should the membrane technology ultimately prove to be not demonstrated for the purposes of this regulation, EPA may promulgate BAT and NSPS requirements for produced water based on other technologies giving strong consideration to BPT as the basis for BAT and NSPS since the costs of alternative technologies are high. The level of pollutant removals will also be considered in evaluating these technologies.

II. Summary of Legal Background

The regulations described in today's notice are being developed under the authority of sections 301, 304 (b), (c), and (e), 306, 307, 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, and 1361; 86 Stat. 816, Pub. L. 92-500; 91 Stat. 1567, Pub. L. 95-217; 101 Stat. 7, Pub. L. 100-4) ("the Act").

The Clean Water Act establishes a comprehensive program to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters" (sec. 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 municipal sewer systems, pretreatment standards are not included in this proposal and are reserved.

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 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 to navigable waters. In arriving at BAT, the Agency 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 (including energy requirements), and such other factors as the Administrator of EPA deems appropriate. The Agency 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) designated the following as conventional pollutants: Biochemical oxygen demanding pollutants (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 impact and energy requirements.

III. Overview of the Industry

A. Exploration, Development, and Production

The offshore subcategory of the oil and gas extraction point source category covers those structures involved in exploration, development, and production operations seaward of the inner boundary of the territorial seas, as defined in Section 502 of the Clean Water Act.

Exploration and development activities for the extraction of oil and gas include work necessary to locate and drill wells. Exploration (only) activities are those operations involving the drilling of wells to determine the potential hydrocarbon reserves. These activities are usually of short duration at a given site, involve a small number of wells, and are generally conducted from mobile drilling units. (Only those exploratory activities with significant site preparation are covered by today's proposal. Significant site preparation, as defined in the 1985 proposal, "shall mean the process of surveying, clearing and preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site.") The major waste streams from exploration activities are drilling fluids and drill cuttings.

Development activities involve the drilling of production wells once a hydrocarbon reserve has been identified. These operations, in contrast to exploration activities, usually involve a large number of wells and are typically conducted from a fixed platform. The waste streams of concern include drilling fluids, drill cuttings, deck drainage, and sanitary and domestic wastes.

Production operations include all work necessary to bring hydrocarbon reserves from the producing formation beginning with the completion of each well at the end of the development phase. The major waste stream from production activities is the produced water waste stream. Other waste streams of concern include produced sand; deck drainage; sanitary and domestic wastes; and well treatment, workover, and completion fluids. Produced water and sand originate with the gas and/or oil product stream and are separated from the oil product during the initial processing of the production stream. Well treatment, completion, and workover fluids are special fluids designed and used to prepare the well for production or enhance recovery of the oil product from, or prevent damage to, the formation.

B. New and Existing Sources

EPA's industry profile estimates are based upon information from the March 1988 "Minerals Management Service Platform Inspection System, Complex/Structure Data Base." According to the Minerals Management Service (MMS) data, 2,260 structures currently produce oil and/or gas in the offshore waters of the United States. This estimate includes all tracts leased offshore in the Gulf of Mexico, California and Alaska. The Agency's estimate of existing structures includes only those platforms that are currently producing known volumes of a specific product (i.e., oil, gas or both). There are no structures in the Atlantic, and the only platforms producing oil in Alaskan waters which are seaward of the inner boundary of the territorial seas are on gravel islands and reinject their produced water. Thus, the Agency's estimate of existing production structures for Alaska is zero.

Structures located in state waters in the Gulf of Mexico are not included in this summary. However, the total volume of produced water being discharged and used as the basis for costing the regulatory options is based on industry estimates which include the state water activities. The Agency has attempted also to profile the number of structures in state "offshore" waters in the Gulf of Mexico. Because of different definitions contained in the state permit records, precise numbers of offshore structures and wells have not been determined. The state offshore records have recorded permitted structures under three subcategories: Onshore (for those structures whose well-head is on land but the bottomhole is offshore), coastal, and offshore. In the charts and maps available from the National Oceanic and Atmospheric Administration (NOAA) and other sources, there is no indication of how many wells there are per structure, whether any of the wells are producing or what product may be produced.

In terms of new source development operations, offshore drilling varies 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. In 1981, there were almost 1500 wells drilled offshore culminating the upward trend of the 1970s. The average number of wells drilled during the 1972–1982 time period was 1100 wells/year. Drilling activity has declined since 1982. Based on the Minerals Management Service's 30-year regionalized forecasts the Agency estimates that between 1986 and the year 2000, assuming no regional constraints on development of offshore oil and gas resources, there will be an average of 980 wells/year drilled offshore nationwide (based on an average barrel of oil equivalent (BOE) price for the years 1986–2000 of $21/barrel). Of these 980 wells/year, 590 wells/year will become producing wells and the remaining 390 wells/year will be dry holes.

EPA has also prepared an estimate of drilling activity which takes into account the recent moratorium and restricted leasing in the Pacific Ocean off of California. On June 26, 1990, the President announced his decision to implement a moratorium on oil and gas leasing and development in federal waters off of California until the year 2000. This "constrained" new well projection estimates that a total of 759 wells/year will be drilled (with 455 of these going into production) between 1986 and 2000 (also assuming $21/barrel (BOE)).

In addition to the offshore areas of the Gulf of Mexico and the California coast, exploration is also occurring in areas within the Chukchi and Beaufort Seas of Alaska, as well as in the Atlantic Ocean, that may lead to new source development and production activities.

Estimates for production are also based on the constrained and unconstrained (restricted and unrestricted) scenarios. The unconstrained profile estimates that 851 platforms will be producing between 1986 to 2000, while the constrained scenario estimates 766 platforms.

C. Waste Streams

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

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

• Domestic wastes.

Drilling fluids (typically termed "muds") and drill cuttings are the most significant waste streams from exploratory operations in terms both of volume and in toxic pollutant control.

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

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

Produced water is the most significant waste stream for production based on its volume of discharge and quantity of pollutants. For purposes of this proposal, deck drainage, sanitary wastes, domestic wastes, produced sand, and well treatment, completion, and workover fluids are all termed "miscellaneous wastes."

Produced water is brought up from the hydrocarbon-bearing strata along with produced oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Drilling fluids means any fluid sent down th Irillhole. 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.

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

Well treatment wastes are spent fluids that result from acidizing and hydraulic fracturing operations to improve oil 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 used in hydraulic fracturing and the accumulated formation sands and other particles, and as scale, that can be generated during production.

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

Detailed discussions of the origins and characteristics of the wastewater effluents from exploration, development, and production are presented in section VIII. The focus of this regulatory effort is on drilling fluids, drill cuttings, and produced waters. Data gathering efforts and data analyses have been focused on these waste streams due to their volumes and potential toxicity. The information on the miscellaneous wastes is more limited. Their volumes are generally smaller, and in most cases either sporadic or are part of the major waste streams. However, due to the concern over the potential toxicity of these wastes, regulations for miscellaneous wastes are being proposed in this notice as well.

In addition, other minor wastes are generated during the offshore exploration development and production activities. These minor wastes are identified and discussed in section VIII.F of today's notice; however, no limits on these wastes are being proposed since these types of discharges are being sufficiently controlled by best professional judgment (BPJ) limits in current permits.

IV. Prior EPA Regulations, Proposals and Other Notices, and General Permits

A. EPA Rulemakings and General Permits

On September 15, 1975, EPA promulgated effluent limitations guidelines for interim final BPT (40 FR 42543) and proposed regulations for BAT and NSPS (40 FR 42572) for the offshore subcategory of the oil and gas extraction point source category. The Agency promulgated final BPT regulations on April 13, 1979 (44 FR 22069), but deferred action on the BAT and NSPS regulations. Table 1 presents the 1979 BPT limitations. These BPT limitations are not being changed by this proposal.

TABLE 1.—BPT EFFLUENT LIMITATIONS (PROMULGATED 1979)

Waste stream	BPT effluent parameter	Limitation
Produced water	Oil and grease	72 mg/l daily maximum 48 mg/l 30-day avg.
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 (min.).
Sanitary-M91M	Floating solids	No discharge.

NOTE: The free oil "no discharge" limitation is implemented by requiring no oil sheen to be present upon discharge.

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 suit (NRDC v. Costle, D.D.C. No. 79-3442 (JHP)), the Agency 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 re-proposal were necessary. Consequently, the Agency withdrew the proposed NSPS on August 22, 1980 (45 FR 56115). The proposed BAT regulations were withdrawn on March 19, 1981 (46 FR 17567).

The Settlement Agreement was revised in April 1990. Under the modified agreement, EPA was 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, as described at 50 FR 34595 (August 26, 1985), by November 16, 1990. The November 26, 1990 proposal (which was signed on November 16) was an initial proposal that was issued in satisfaction of this provision of the Settlement Agreement. EPA is to promulgate final guidelines and standards covering these waste streams by June 19, 1992.

EPA also was to determine by November 16, 1990 whether to propose effluent limitations guidelines and new source performance standards covering deck drainage and domestic and sanitary wastes and, if it determined to do so, to promulgate final guidelines and standards covering those waste streams by June 30, 1993. EPA has determined that it is appropriate to propose effluent limitations guidelines and new source performance standards covering deck drainage and domestic and sanitary wastes. The Agency included such proposals in the November 26 proposal and they are included in today's notice.

The Agency is using its best efforts to comply with the promulgation dates established in the modified Settlement Agreement and currently expects to meet them.

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.

On August 26, 1985 the Agency proposed BAT, BCT, and NSPS regulations to control the discharge of pollutants from the offshore oil and gas extraction subcategory (50 FR 34592) ("1985 proposal"). 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. No BAT effluent limitations guidelines were proposed for the produced water waste stream; only NSPS and BCT requirements for produced water were proposed.

The key provisions of the 1985 proposal were as follows:

—Limit oil and grease to 59 mg/l daily maximum and 48 mg/l monthly average for produced water (NSPS only) for all oil facilities located in deep water (Note: The definitions of deep and shallow water are described in section V of today's notice), for all oil and gas facilities regardless of location or water depth, and for all exploratory facilities regardless of location or water depth. This limitation was based on the best operation of the BPT control technology (gas flotation). NSPS for oil facilities located in shallow water prohibited the discharge of produced water.

—Prohibit the discharge of free oil in drilling fluids, drill cuttings, deck drainage, produced sand, and well treatment fluids.

—Prohibit the discharge of diesel oil in detectable amounts in drill cuttings and drilling fluids.

—Limit the acute toxicity of drilling fluid discharges to a minimum 96-hour LC50 of 3 percent (30,000 ppm) as measured in the diluted suspended particulate phase (SPP).

—Limit the discharge of cadmium and mercury in drilling fluids to a maximum of 1 mg/kg each at the point of discharge.

The proposed BCT limitations guidelines for produced water covered the conventional pollutant oil and grease and were equal to the previously promulgated BPT effluent limitations guidelines. For deck drainage, drilling fluids, drill cuttings, produced sand, and well treatment fluids, proposed BCT limitations prohibited the discharge of free oil. BCT effluent limitations guidelines for additional conventional pollutant parameters in deck drainage, drilling fluids, drill cuttings, produced sand, and well treatment fluids were reserved for future rulemakings.

On October 21, 1988, the Agency published 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 the Agency collected after publication of the 1985 proposal. New information was presented regarding the diesel oil prohibition and the toxicity limitation. New compliance costing and economic analysis results were presented 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, alternative requirements for limitations of 5 mg/kg cadmium and 3 mg/kg mercury in the stock barite based on the use of existing barite supplies, or at 2.5 mg/kg cadmium and 1.5 mg/kg mercury in the drilling fluids (whole fluid basis) were noticed for comment.

On January 9, 1989, the Agency 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.

As described in section I, on November 26, 1990 the Agency published a notice as an initial proposal and 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.

In addition, EPA has issued a series of general permits that set BAT and BCT limitations applicable to sources in the offshore subcategory on a Best Professional Judgment (BPJ) basis under 402(a)(1) of the Clean Water Act. See e.g., 51 FR 24897 (July 9, 1988) (Gulf of Mexico 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 Permit). Where pertinent, today's notice discusses the major provisions of these general permits in relation to the effluent guidelines and standards being proposed. The rulemaking record for this proposal 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 Seas General Permit was the subject of industry challenge. *American Petroleum Institute* v. *EPA*, 787 F.2d 965 (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 for this proposal.

B. Relationship of Today's Proposal to the 1985 Proposal

The proposal being issued today does not supercede the 1985 proposal entirely, but rather changes the proposal in certain areas. Below is a discussion of the parts of the 1985 proposal that remain the same and the parts that are being changed. Reasons for the changes are discussed in the appropriate preamble sections as indicated.

1. Parts Changed from the 1985 Proposal

New data and information gathered since the 1985 proposal have led the Agency to consider and develop new treatment and control options for the offshore oil and gas waste discharges. New information regarding data gathering and analytical methods is outlined in section VII. New treatment performance data are presented in section X. The new treatment and control options developed as a result of this new information are presented in sections XII–XIV. Also included in these sections are a discussion of the 1985 options and how they differ from the current proposals. The revised costs and economic analyses performed on these new options are summarized in sections XV and XVI. Other sections of the 1985 proposal that have been changed are listed below.

a. Section II of the 1985 Proposal: Scope of Today's Rulemaking. In 1985, no BAT limitations were proposed for produced water. Today's notice is proposing BAT and NSPS effluent limitations for produced water for oil and grease as an indicator pollutant. The limitations being proposed today are based on membrane filtration and set limits on oil and grease at 7 mg/l monthly average and 13 mg/l daily maximum not to be exceeded.

For drilling fluids, BAT and NSPS discharge limitations were proposed in 1985 for all drilling structures. This reproposal of BAT and NSPS is equivalent to the 1985 proposed discharge limitations for those structures located outside of 4 miles from the inner boundary of the territorial seas (shore). For wells located 4 miles or less from shore, zero discharge is proposed in today's notice.

For drill cuttings, the 1985 BAT and NSPS proposal included a prohibition on the discharge of diesel oil and free oil for all structures. Today's notice is proposing the same limitations for drill cuttings as for drilling fluids.

The 1985 BAT and NSPS proposal included a prohibition on the discharge of free oil for deck drainage, produced sand, and well treatment fluids. For BAT and NSPS, today's notice is proposing: (1) That deck drainage be subject to the same limitations as produced water during production operations and to requirements equal to the current BPT limits during the drilling operations before any wells on a given structure are put into production; (2) that zero discharge be required for produced sand; and (3) that for those well treatment, completion, and workover fluids that resurface as a discrete slug, zero discharge be required for the slug and a 100 barrel buffer on both sides of the slug. For those treatment, completion, and workover fluids that cannot be segregated from the produced water, the produced waters limitations would apply. In the case of acid workover fluids which resurface as a slug, neutralization (pH control) and application of the produced water limitations would be required. As in the 1985 proposal, no BAT requirements for domestic wastes or sanitary wastes are being proposed. NSPS for sanitary wastes were proposed in 1985 as equal to BPT. NSPS for domestic wastes was proposed in 1985 to prohibit the discharge of floating solids. Today's notice today proposes BPT, plus a requirement for no visible foam, as NSPS for domestic wastes. Proposed NSPS for sanitary wastes is identical to the 1985 proposal.

As in 1985, today's notice proposes BCT for produced water as being equal to BPT limitations on oil and grease. BCT limitations proposed in today's notice for deck drainage and well treatment, completion and workover fluids are identical to the 1985 proposed limitations equal to the BPT prohibition on the discharge of free oil. BCT for drilling fluids and drill cuttings was proposed in 1985 as being equal to BPT. In today's notice, BCT for drilling fluids and drill cuttings is proposed as zero discharge for structures located within four miles from shore and BPT for those structures at distances greater than four miles from shore. In 1985, proposed BCT for produced sand prohibited the discharge of free oil. As proposed in today's notice, BCT limitations would require zero discharge of produced sand. Today's proposed BCT limitations for sanitary wastes are identical to the 1985 notice and set BCT equal to BPT. Today's notice also proposes BCT limitations for domestic wastes prohibiting the discharge of floating solids.

b. Section V of the 1985 Proposal: Overview of the Industry. The location, size, and number of platforms, as well as the status of the oil and gas industry has been updated. New profile information is included in today's proposal in section III.

c. Section XIII of the 1985 Proposal: Non-Water Quality Environmental Impacts. Non-water quality environmental impact analyses on the new options EPA developed for this rulemaking have had significant influence on the selection of preferred options for proposal. Section XVIII of today's proposal presents a discussion of the non-water quality environmental impacts associated with the new options.

d. Appendix 4 of the 1985 Proposal: Regulatory Boundaries. This appendix lists regulatory boundaries associated with the shallow water classification proposed in 1985. The boundaries as proposed have not changed, only the applicability of this classification. The 1985 proposal states that this appendix is applicable to shallow production structures subject to a zero discharge requirement only. Today's notice deletes this statement so as not to limit the applicability of the shallow classification to zero discharge requirements. This change is included in appendix C of today's notice.

e. Appendix 2 of the 1985 Proposal: Analysis of Diesel Oil in Drilling Fluids and Drill Cuttings Analytical Method. Changes to this method were presented in appendix A of the 1988 Notice of Availability. These changes were a result of experience obtained during the Diesel Pill Monitoring Program. An incomplete version of the analytical method was published in the 1988 notice. A **Federal Register** notice was published later which contained the correct version (54 FR 634, Jan. 9, 1989).

2. Parts Not Changed from the 1985 Proposal

While the data acquired and treatment and control options for the offshore oil and gas industry are different in the current proposal, many items proposed in 1985 remain the same. These items, are not included in this proposal. Rather, those items that have not changed since 1985 are now subject to promulgation along with the items being proposed in today's notice. Those items proposed in 1985 that are not being affected by this reproposal are listed below.

a. Section IX of the 1985 proposal. Industry Subcategorization.

b. Section XI of the 1985 proposal. Selection of Control and Treatment Options where it concerns the toxicity limitation of 30,000 ppm in the suspended particulate phase for drilling fluids.

c. Section XI.B of the 1985 proposal. The proposed amendment to the BPT definition of "no discharge of free oil".

d. Section XIV of the 1985 proposal. Definition of "new source."

e. Section XV of the 1985 proposal. Best Management Practices.

f. Section XVI of the 1985 proposal. Upset and Bypass Provisions.

g. Section XVII of the 1985 proposal. Variances and Modifications, except for a new discussion on Stormwater Events included in section XX of today's proposal.

h. Section XVIII of the 1985 proposal. Relationship to NPDES Permits.

i. Appendix 1 of the 1985 proposed regulation. Static Sheen Test.

j. Appendix 3 of the 1985 proposed regulation. Drilling Fluids Toxicity Test analytical method.

V. Industrial Sectors

A. Shallow/Deep Waters

One method used in today's notice (and in the previous 1985 proposal) divided the industry into two sectors: Those in shallow waters and those in deep waters. The Agency proposed depth limits in order to allow for an option of onshore reinjection of produced water from those structures located in shallow water. The Agency found that in shallower waters a high percentage of the existing production platforms pipe produced waters to shore for treatment rather than treating produced waters on the platform. The Agency has also determined that the cost of drilling and equipping reinjection wells on land is less than drilling reinjection wells at the platform.

In the 1985 proposal, the Agency proposed variable depth limits that defined "shallow" for different offshore areas which were based on bathymetric features and industry practice for produced water treatment and reinjection onshore. This proposed method of dividing the industry has not changed since 1985 but is discussed in today's notice for the reader's information.

Through the compilation of data from industry the following water depths were proposed to be shallow water:

Gulf of Mexico: Industry data indicated that 52 percent of all the projected new sources in 15 meters or less of offshore waters would pipe produced water to shore. The Agency believed the same percentage of platforms in water depths of 20 meters or less could pipe to shore and reinject.

Atlantic: The water depth of 20 meters was proposed as shallow for this region since there was no historic data for production.

California: It was determined that 60 percent of the active production platforms located in water depths of 50 meters or less piped to shore for treatment while only 8 percent of the structures in depths greater than 50 meters piped to shore for treatment. Based on this information, a depth of 50 meters or less was proposed as shallow water in California.

Alaska: It was assumed that southern Alaska bathymetry (ocean depth) was similar to California's bathymetry, so a water depth of 50 meters or less was proposed to be shallow. The southern Alaska region includes the Bristol Bay, Aleutian Island Chain, Cook Inlet, and the Gulf of Alaska. For other parts of Alaska the Agency proposed shallow water to be of a depth of 20 meters or less in the Norton Sound and 10 meters or less in the Beaufort Sea. The water depths in the North were proposed to be less than the 50 meters for southern Alaska because the harsher climates in the more northern region made piping to shore for treatment less probable.

For determination of water depth, appendix 4, "Regulatory Boundaries," of the 1985 proposed regulations (and appendix C of today's notice) referenced nautical charts or bathymetric maps available from the National Oceanic and Atmospheric Administration. The water depth of the structure was defined to be based on the proposed location of the structure's well slot or produced water discharge point.

The shallow/deep water grouping was considered in 1985 only for the production phase of the industry. This distinction was evaluated for certain zero discharge options based on reinjection of produced water. Today's current reproposal includes the same shallow/deep water classification for produced waters; in addition, those classifications also apply to drilling fluids and drill cuttings. As discussed later in section XII, a zero discharge option for drilling wastes is being considered for today's proposal. The technology basis for a zero discharge requirement for drilling wastes is barging to shore for disposal. In addition to requiring zero discharge for all structures, EPA considered requiring zero discharge only for those new wells drilled in shallow water in order to minimize the non-water quality environmental impacts from barging and land disposal of these wastes.

Table 2 presents the number of existing producing structures by geographic region, production type, and water depth and shows that 99 percent of the existing offshore structures are in the Gulf of Mexico. Shallow water structures account for approximately 58 percent of existing structures.

TABLE 2.—NUMBER OF EXISTING PRODUCING STRUCTURES BY GEOGRAPHIC REGION, PRODUCTION TYPE, AND WATER DEPTH

Region	Shallow Water				Deep Water				Total all
	Oil only	Oil and gas	Gas only	Total shallow	Oil only	Oil and gas	Gas only	Total deep	
Gulf	126	497	676	1,299	35	471	428	934	2,233
Pacific	0	10	0	10	0	16	1	17	27
Alaska	0	0	0	0	0	0	0	0	0
Atlantic	0	0	0	0	0	0	0	0	0
Totals	126	507	676	1,309	35	487	429	951	2,260

The definition of shallow depth for use with new well drilling is the same as the definition used in the 1985 proposals for production activities. Table 3 presents the estimate of the number of new wells to be drilled annually by geographic region and water depth (based on projections for the years 1986–2000, at $21/barrel). This shows that a greater percentage of the drilling is expected for new wells in deep waters than in shallow waters (approximately 71 percent).

TABLE 3.—ESTIMATE OF THE NUMBER OF NEW WELL DRILLINGS PER YEAR BY GEOGRAPHIC REGION AND WATER DEPTH

[1986 to 2000: 980 wells/year will be drilled (60 structures/year) 590 Producing Wells; 390 dry holes]

Region	Shallow water	Deep water	Total
Gulf of Mexico	265	450	715
Pacific	10	227	237
Alaska	9	3	12
Atlantic	0	16	16
Totals	284	696	980

B. Distance From Shore

In addition to those options which divided the industry by water depth, EPA evaluated regulatory options which grouped the industry based on distance and a well or structure from shore. This evaluation showed that the non-water quality environmental impacts associated with the zero discharge options for drilling wastes warranted further investigation and/or consideration of adopting different regulatory approaches for different portions of the offshore industry.

The impacts of concern are the fuel requirements and air emissions resulting from the barging of solid wastes to shore for disposal. Also, EPA was concerned with the long-term available on-land disposal capacity to support the zero discharge options. Thus, EPA investigated regulating the industry in a manner which would mitigate these non-water quality environmental impacts.

EPA evaluated a breakdown of structure location based on distance (in miles) from shore instead of depth of well. The distances evaluated were 4, 6, and 8 miles from shore. As a matter of consistency, these distances offshore were evaluated for produced waters as well as drilling fluids and drill cuttings. EPA also attempted to evaluate a distance of 3 miles from shore since the delineation between state and federal leased water areas for the purpose of oil and gas extraction provides a well-defined separation point. However, due to the problems in identifying existing offshore production facilities from the state data bases and the NOAA charts (as previously discussed in section III.B), an accurate count of facilities at 3 miles or less from shore could not be estimated. For the 4, 6, and 8 mile distances, MMS empirical data and projections were a basis for straight line extrapolations for distances at 3 miles and less for existing new sources. The Agency still considers the 3 mile delineation as a viable option and may use this in the final rule if accurate information on the number of existing production facilities and new source projections can be obtained for these waters.

EPA determined in its analysis of regulatory options that the use of a 4 mile category is preferable to the other distances evaluated (6 and 8 miles) because either the further distances from shore (8 miles or greater) do not reduce non-water quality environmental impacts sufficiently, or the difference between the pollutant removals at 6 miles from those at 4 miles are not significant. The 4 mile option is the Agency's preferred option based on distance. However, the Agency will consider setting the final rule on distances other than 4 miles with the receipt of additional state waters information on the number of existing structures and new well drilling projections.

Table 4 presents the number of existing producing structures by geographic region and production type according to the 4 mile cutoff. Approximately 208 structures are 4 miles or closer to shore. These represent approximately 9 percent of the total. This same percentage of structures, although not necessarily the same structures, would be equivalent to regulating the drilling and production activities at a water depth of 6.3 meters in the Gulf of Mexico.

TABLE 4.—EXISTING PRODUCING STRUCTURES ACCORDING TO DISTANCE FROM SHORE

Region	Less than or equal to 4 miles					Greater than 4 miles					Total
	Oil only	Oil and gas	Gas only	Sub-total	Per-cent	Oil only	Oil and gas	Gas only	Sub-total	Per-cent	
Gulf	50	63	84	197	9	111	905	1,020	2,036	91	2,233
Pacific	0	11	0	11	41	0	15	1	16	59	27
Alaska	0	0	0	0	0	0	0	0	0	0	0
Atlantic	0	0	0	0	0	0	0	0	0	0	0
Totals	50	74	84	208	0	111	920	1,021	2,052	0	2,260

Table 5 presents the estimate of the number of new well drillings annually by geographic region according to the 4 mile cutoff (for the years 1986–2000 at $21/barrel). As can be seen by the table, approximately 16 percent of the estimated 980 new wells will be in waters 4 miles or less from shore.

TABLE 5. Estimate of New Well Drillings Per Year According to Distance from Shore "Unconstrained Development"

Region	Less than or equal to 4 miles	Greater than 4 miles	Total
Gulf	72	643	715
Pacific (off California [1])	71	166	237
Alaska	9	3	12
Atlantic	0	16	16
Total			980

[1] This projection assumes no moratorium or restricted leasing off the coast of California.

This estimate is based on assumptions contained in the MMS Table 4 projections which do not take into account the recent moratorium and restricted leasing in the Pacific off California. A more "constrained" projection of new wells based on these conditions gives approximately 759 new wells drilled annually (for the years 1986–2000 at $21/barrel (BOE)). Table 6 shows projections on a regional basis for this constrained scenario and estimates approximately 11 percent of the new wells in waters 4 miles or less from shore.

TABLE 6. Estimate of New Well Drillings Per Year According to Distance from Shore "Constrained Development"

Region	Less than or equal to 4 miles	Greater than 4 miles	Total
Gulf	72	643	715
Pacific (off California)	71	32	32
Alaska	9	3	12
Atlantic	0	0	0
Total			759

VI. Regulatory Definitions

A. Domestic Waste

The August 26, 1985 proposal defines domestic waste as wastewater resulting from laundries, galleys, showers, etc. In today's proposal, other examples of domestic wastes are added for the purpose of clarity. These include wastes from safety shower and eye wash stations, hand wash stations, and fish cleaning stations. This clarification of the proposed definition does not change the regulation or its economic impact.

B. Well Treatment, Completion, and Workover Fluids

The 1985 proposal defines well treatment fluids as "those fluids used in stimulating a hydrocarbon bearing formation or in completing a well for oil and gas production, and drilling fluids used in re-working a well to increase or restore productivity."

EPA is proposing to change this definition of well treatment fluids to make it similar to the definition being proposed in the coastal drilling permits for Texas and Louisiana by EPA's Region VI. This new definition makes a distinction between well treatment fluids, completion fluids, and workover fluids. The following definitions are being proposed in today's notice:

Well Treatment Fluids: "Any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled." These fluids move into the formation and return to the surface as a slug with the produced water. Stimulation fluids include substances such as acids, solvents and propping agents.

Well Completion Fluids: "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." These fluids move into the formation and return to the surface as a slug with the produced water.

Workover Fluids: "Salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures." High solids drilling fluids used during workover operations are not considered workover fluids by definition. Packer fluids—low solids fluids between the packer, production string, and well casing—are considered to be workover fluids.

The definitions above distinguish treatment, completion, and workover fluids from drilling fluids and each other based on clear descriptions of form and function. Drilling fluids remaining in the wellbore during logging, casing, and cementing operations or during temporary abandonment of the well are not considered completion fluids and are regulated by drilling fluids requirements.

Both high and low solids drilling fluids used during workover operations are not considered workover fluids and must also meet drilling fluids effluent limitations.

Production operations are defined as "operations including work necessary to bring hydrocarbon reserves from the producing formation beginning with the completion of each well in the development phase;" thus, treatment, completion, and workover fluids, as defined above, are considered part of the production phase. If these fluids do not come back up as a discrete slug, they will either remain in the hole, or diffuse within the well's formation fluids and resurface as part of the produced water.

C. Produced Sand

Sand is obtained with the fluids from the formation during the production process. This sand, termed "produced sand," is defined (1985 proposal) as "slurried particles used in hydraulic fracturing and the accumulated formation sands and scale particles generated during production." The sand is separated out from the produced water, washed with either water or solvent, and is either discharged overboard with the produced water waste stream or is stored in 55 gallon drums and transported to shore for disposal.

EPA is proposing to make this definition more specific to include "desander discharge from the produced water waste stream and blowdown of the water phase from the produced water treating system." Thus, for the options considered for this proposal, the definition of produced sand is being modified to include the following sentence:

> Produced sand also includes desander discharge from the produced water waste stream and blowdown of the water phase from the produced water treating system.

D. Development Facility and Production Facility

EPA is proposing to change the 1985 proposal definitions of "development facility" and "production facility" to more accurately reflect the waste streams that occur during these phases of the industry. The definition of development facility is being changed to cover only the drilling portion of the operation. Thus, the major waste streams associated with this phase are drilling fluids and cuttings.

The definition of production facility is being proposed to include the completion phase of the operation as well as actual hydrocarbon extraction. The major waste stream associated with this phase is produced water. Since well treatment and completion fluids resurface (if they surface at all) along with the produced waters, EPA believes it appropriate to associate well treatment and completion with the production phase.

VII. Data Gathering Efforts

A. Existing Information

In October 1988, the Agency published a Notice of Data Availability (53 FR 41356) which presented new technical, economic, and environmental information relating to the development of BAT and NSPS effluent guidelines limitations for the drilling fluid and drill cuttings waste streams. This new information was submitted to the Agency in public comments in the response to the 1985 proposal. The notice was organized in two parts. Part 1 of the notice discussed key issues surrounding the drilling fluids toxicity limitation, the proposed toxicity test method, the prohibition on the discharge of drilling fluids containing diesel oil additives, a re-evaluation of industry compliance costs, an economic impact assessment of the revised cost estimates and environmental impacts of the discharge of cadmium and mercury in drilling fluid waste streams. It also presented two variations on the August 1985 proposed regulatory approach related to the mercury and cadmium limitations in the whole drilling fluids and stock barite used in the drilling fluids.

Part 2 of the notice discussed information gathered on new treatment technologies for controlling the oil content of drilling wastes. Data on the performance and cost of thermal distillation/oxidation and solvent extraction technologies for treating drilling fluids and drill cuttings were presented for public review and comment. This information was being considered for the development of an oil content limitation on drilling waste streams. In addition, an analytical method for determining diesel oil and oil content was included for comment.

B. New Studies

Since the 1988 notice, additional studies were conducted in response to concerns over various aspects of this rulemaking. Such concerns include: The variability of the test method used to measure toxicity of drilling fluids and drill cuttings, additional technologies available for produced water treatment, procedures for the static sheen test, radioactivity associated with produced waters, and non-water quality environmental impacts associated with various treatment and control options. The evaluation of non-water quality environmental impacts including solid waste disposal, air emissions and fuel requirements are discussed separately in section XVIII of today's notice. A summary of new information acquired is given below.

1. EPA Variability Study for Drilling Fluids Toxicity Test

The 1985 offshore oil and gas proposal included a limitation on the toxicity of discharged drilling fluids. The toxicity limit is expressed as the concentration of the suspended particulate phase (SPP) from a sample of drilling fluid that would be lethal to 50 percent of a particular species exposed to that concentration of the SPP, i.e., the LC50 of the discharge. The species used in the toxicity test is *Mysidopsis bahia,* otherwise called mysid shrimp. The Agency proposed a toxicity limitation of 30,000 ppm (SPP) based on the toxicity of the most toxic of eight generic drilling fluids that were in general use at the time of proposal. In addition, permit writers have set this limit as their best professional judgment of BAT. It is currently included in the general permit for oil and gas activities on the outer continental shelf of the Gulf of Mexico.

several individual offshore oil and gas permits for California, and in Alaska.

As part of the evaluation of methods under section 304(h) of the Clean Water Act and as a response to comments from the 1985 offshore oil and gas proposal, the Agency has recently conducted a study of the variation in results from the toxicity test for drilling fluids. The study was conducted in two phases.

In Phase I, each lab was required to conduct one toxicity test on a sub-sample of generic drilling fluid #3 (lime mud). The participating labs included 2 Agency labs and 28 contract labs. The contract labs included all commercial, academic, and industry labs known to the Agency that claimed to have experience with some form of toxicity testing and were willing to participate. The Agency knows of over 100 commercial, academic, and industry labs that are potentially capable of conducting the required test.

In Phase II, each lab was required to conduct two toxicity tests on sub-samples of generic drilling fluid #8 (lignosulfonate freshwater mud) and two toxicity tests on sub-samples of generic drilling fluid #8 with 3 percent mineral oil. Contract labs were selected at random from those contract labs that demonstrated the ability to conduct the toxicity test at a competitive price.

A summary of the study results is presented in table 7. The "selected" labs in the summary for generic fluid #3 were included because a review of the raw lab reports indicated that they correctly followed the test protocol they received as part of the study. The primary summary statistics included in the table are the average toxicity (LC50), standard deviation (SD), prediction intervals, and the coefficient of variation (CV).

Table 7.—PRELIMINARY RESULTS FROM THE VARIABILITY STUDY OF THE DRILLING FLUIDS

Drilling fluid	Responses	No. of labs	Average LC50 (percent)	SD (percent)	CV (percent)
Combined within- and between-lab variation					
Generic Fluid #3	All	28	25.6	12.0	47.1
	Selected	16	22.6	5.96	26.4
Generic Fluid #8	All	9	50.9	19.4	38.1
Generic Fluid #8 (3% Oil)	All	9	0.27	0.36	133.9

Drilling fluid, upper	Responses	No. of labs	Average LC50 (percent)	SD (percent)	CV (percent)	Lower (percent)	95% prediction interval
Within-lab variation							
Generic Fluid #8	All	9	59.9	10.4	20.5	26.6	75.2
Generic Fluid #8 (3% Oil)	All	9	0.27	0.20	72.0	+0.0	0.73

NOTES:
LC50 calculated using Probit Analysis by Maximum Likelihood with optimization for control mortality.
"Average LG50" is the average of the average LC50 for each lab.
Standard Deviation (SD) for combined within- and between-lab variation is the square root of the sum of mean squares for within-lab variation plus the sum of mean squares for between lab vanation. SD for within-lab variation is the square root of the sum of squares for within-lab variation.
Coefficient of Vanation (CV) is SD/Average LC50.
Prediction Interval is for within-process variation from labs that have demonstrated the ability to conduct EPA's toxicity test.

The average LC50 was slightly higher (less toxic) than expected for the sample of generic drilling fluid #3 and for the sample of drilling fluid #8. However, the average LC50 reported for drilling fluid #8 with 3 percent mineral oil was lower (more toxic) than expected. It is important to note that each of these averages is based on a sub-sample from a single well-mixed sample of drilling fluid. Hence, the variation found in this study is related only to within- and between-lab variation and any average result applies only to that one sample of drilling fluids. Generalizations to average levels for other batches of the same generic drilling fluid or the same generic drilling fluid with mineral oil are not supported by these data.

The standard deviations (SD) reported in Table 7 indicate the magnitude of variation found in lab results for a particular drilling fluid system. Because only one test per lab was conducted on the sample of generic drilling fluid #3 it is not possible to estimate within-lab variation for that sample. In order to provide comparable statistics, combined within- and between-lab standard deviations are presented for all samples tested in the study. However, the Agency is primarily interested in estimates of within-lab variation so these estimates are presented for generic drilling fluid #8 and generic drilling fluid #8 with 3 percent mineral oil. Estimates of within-lab variation from competent labs quantifies the natural variability inherent in the measurement process while between lab estimates of variability quantifies lab bias. Lab bias describes the situation when all results of a particular lab are consistently above or below the multi-lab average result. The Agency believes that between lab variation is caused by consistent lab practices that can be modified through learning from experience. Additionally, an hypothesis that lower LC50s are linked to lower standard deviations is suggested by table 7 and the Agency is considering further statistical analysis of this relationship.

Prediction intervals for within-lab variation reported in table 7 are calculated on the results from the number of labs indicated in the table and adjusted to account for the current population of 16 labs that have demonstrated the ability to conduct the Agency's toxicity test. These intervals indicate that within-lab variation would be unlikely to change the compliance status of the tested samples. In other words, when the LC50 was above 3 percent the Agency is 95 percent confident that within-lab variation would not cause a new measurement on that sample of drilling fluid to be below 3 percent. When the LC50 was below 3 percent, the Agency is 95 percent confident that within-lab variation will not cause a new measurement to be above 3 percent. If lower LC50s are linked to lower standard deviations, then the confidence intervals for LC50s will become smaller as the substance becomes more toxic.

Coefficients of variation (CV) indicate how much, on a percentage basis, the

LC50 could vary within a single standard deviation. However, for regulatory purposes, the Agency is primarily concerned with the magnitude of change in toxicity and industry's ability to use either product substitution with drilling fluids or treatment/disposal so that, based on within-lab variation, industry would be able to comply with proposed limitations.

Preliminary analysis of the multi-lab results for toxicity tests from the recent study continue to support the conclusion that the test protocol is adequate for use in a regulatory framework. Industry will be able to use either product substitution in order to discharge drilling fluids that comply with a 30,000 ppm limitation on toxicity or available technology to avoid discharging drilling fluids or drill cuttings:

2. Performance of Granular Media and Membrane Filtration Technologies on Produced Water

Filtration, as an add-on technology to BPT, is being considered as an option for treatment of the produced water waste stream for both BAT and NSPS effluent limitations guidelines. To assess the levels of pollutants in effluents from treatment and the efficiency of reducing pollutants in produced water, a "three facility study" of granular media filtration was conducted by the Agency in the summer of 1989. In addition, data were received on the performance of membrane filtration from an equipment vendor. The performance of membrane filtration differs from granular media filtration in that membrane filtration removes much of the soluble oil and grease from the produced water as well as suspended solids and the insoluble oil and grease fraction. A summary of the results of the use of both types of filtration technologies on produced water is discussed below.

The Agency selected facilities for the "three facility study" based on: (1) Their use of granular filtration, and (2) the oil and grease level being somewhat comparable to the BPT level prior to filtration. Not all of these facilities were located offshore (one was offshore, one was onshore, and one was coastal). However, the efficiency of granular media filters at each location is not dependent upon the facility's location. Each facility was unique in its handling of produced waters prior to filtration; however, two of the three use chemical feed prior to filtration and all facilities reinjected their produced water after filtering. Specifically, the onshore facility uses fresh makeup water, combines it with the produced water, and adds a chemical feed (polymer) prior to the filtration unit. The offshore facility (a three-well platform located off the coast of California) combines produced waters from the three wells after oil/water separation before entering the multimedia granular filtration unit. At the coastal facility, an "ultrahigh" rate filtration unit is utilized and a polymer is added to the produced water prior to entering the filtration unit.

Influent and effluent produced waters into each filtration unit were analyzed. At two of the facilities, the filtration influent waters are the effluent waters from gas flotation units (BPT technology basis). One facility does not use gas flotation. Statistical analyses of data from the "three facility study" were conducted. Results of these analyses and the examination of operational information showed that results from only the two facilities which used polymers provided satisfactory filter performance data. A summary of these results, shown in Table 8, demonstrates a 40 to 60 percent removal of oil and grease, from levels approximately at the BPT long-term average level of 25 mg/l, to 11.3 mg/l for the two facilities using polymer addition.

TABLE 8.—THREE FACILITY STUDY STATISTICAL RESULTS

Parameter	Long Term Average Concentrations (mg/l)	
	Influent	Effluent
Oil and Grease	27.26	11.33
Total Suspended Solids	44.83	21.17

NOTE: Only the onshore and coastal facilities data are included.

A vendor of membrane filtration equipment has supplied the Agency with limited data from a membrane separation unit that is operating in the Gulf of Mexico and several pilot scale evaluations at facilities in offshore, coastal, and onshore locations. Results from the full-scale operation indicate that, in most cases, regardless of the values of TSS and oil and grease in the influent, effluent values of less than 5 mg/l of oil and grease are readily attained. In addition, this technology shows potential for more efficient removals of soluble oil and grease (organics) than the BPT technology and granular media filtration technology. Further discussion of this technology and its performance is included in section X of today's notice.

C. Analytical Methods

1. Static Sheen Test

Since the 1985 proposal of a new analytical procedure to measure free oil, known as the "Static Sheen Test," other variations to this method have been suggested. EPA has reviewed three other methods: one developed by its Region IX office, one by its Region X office, and an additional version known as the "minimal volume" method. A comparison of the differences between the 1985 proposal and Region IX's suggested method is presented below:

- Receiving water—The "original" procedures require ambient seawater to be utilized as the receiving water in the test whereas Region IX procedures call for tap/drinking water.
- Mixing/stirring—The "original" procedures call for thorough mixing of both the test material samples and the mixture of test material and receiving water. Region IX procedures delete all references to mixing test material samples and require efforts to "minimize any mixing of the test material in the test water." This is because of test interferences due to bubbling/foaming and particulate surface deposits caused by mixing or stirring.
- Sample volumes/weights—The "original" procedures specify drilling fluid, deck drainage, or well treatment fluid samples of 0.15 mL and 15 mL and drill cuttings or produced sand samples of 1.5 g and 15 g on a wet weight basis. Region IX procedures call for 15 mL samples for drilling fluid, deck drainage, or well treatment fluid samples and 15 gram (wet weight) samples of drill cuttings or produced sand. Region IX's requirements simplify the test by requiring only the largest sample of the waste stream.
- Observations—The "original" procedures require observations to "be made no later than one hour after the test material is transferred to the test container." Region IX requirements dictate that observations occur "immediately, and at 15, 30, and 60 minutes after the test material is transferred to the test container."
- Sheen designation—"Detection of a silvery or metallic sheen, gloss, or increased reflectivity; visual color; or iridescence on the water surface" is considered to be an indication of "free oil" under the "original" guidelines. Under Region IX guidelines, the discoloration must cover "more than one-half of the surface of the test water" and "the appearance of a sheen must persist for at least 30 seconds" to be classified as indicating the presence of "free oil."

The method suggested by Region X is the same as the 1985 proposal except that the free oil detection criterion is similar to that for Region IX's version (that a sheen must cover more than one half of the surface of the test water).

The minimal volume test is a procedure designed to be more appropriate for laboratory analysis because of the smaller volumes: A 5 ml sample of drilling fluid is used instead of 15 ml. Drinking water is used as the receiving water and mixing is minimized. Observations are made immediately and 5 minutes after combining the test sample and receiving water. The free oil detection criterion is similar to the 1985 proposal.

A study was performed by industry which compared the static sheen methods. This study, among other aspects of the test, investigated the tendency of false positive readings for each method. False positive results are those that show a free oil detection for non-oil containing samples. A percentage of false positives results gives an indication of the reliability of the test. The 1985 proposed method, which was also the same method used by Region IX at the time of the study, showed 16.76 percent false positives (63 samples out of 376). The region X method showed 2.5 percent and the minimal volume method, 21.86 percent.

EPA is considering these variations on the static sheen test, although the method proposed in 1985 remains preferred. The Agency is soliciting comments, on this and the other three procedures as to the appropriateness of each method.

2. Diesel Oil Detection and Total Oil Content—Proposed Method 1651

The 1985 proposal included proposed methods for detecting the presence of diesel oil in drilling fluids and drill cuttings waste streams. The method based on retort distillation and gas chromatography, was subsequently modified based on experience gained during the conduct of the Diesel Pill Monitoring Program (DPMP). The DPMP study was performed in order to evaluate the efficiency of diesel recovery practices after spotting of a diesel pill. This study, performed in 1986–1987, is described in the 1988 Notice of Availability along with the modified analytical procedure (which was corrected in the January 1989 notice at 54 FR 634).

This modified procedure was the method accepted by EPA. No comments were received on it after the 1988 and 1989 notices. The method has an estimated detection limit of 100 mg/kg (0.02 percent of diesel oil). Documentation on precision and accuracy measurements of the test method is included in the record for the 1988 notice of availability.

The Offshore Operators Committee (OOC) of the American Petroleum Institute (API) conducted the Diesel Pill Monitoring Program (DPMP) in 1986 and 1987. One of the objectives of this program was to measure the recovery of diesel oil from drilling fluids and drill cuttings wastes. The test method used to determine the concentration of diesel oil employed a thermal (retort) extraction to separate the diesel oil from the mud system, solvent extraction to separate the diesel oil from the water and inorganic salts co-extracted in the thermal desorption process, evaporation of the solvent to concentrate the diesel oil in the solvent, and determination of the diesel oil in the solvent by gas chromatography. (For an explanation of gas chromatography, see the preamble to the test procedures for determination of pollutants in wastewater [49 FR 43234].)

This test method was practiced by two laboratories, one under contract to EPA and one under contract to industry. One of the conclusions from the DPMP was that thermal extraction/gas chromatography was capable of rigorously identifying and quantifying diesel oil in drilling wastes when the oil used to spot the pill was used as the reference oil for calibration of the gas chromatography, and when other potentially interfering oils were not present in the mud at concentrations large enough to affect the result. In instances where a reference oil were not available, number two diesel oil was used as the reference, and its use made identification and quantification of the diesel oil more difficult than when the reference oil was used. In instances where other oils were present in the wastes, determination of the identity and concentration of the diesel oil were also made more difficult, especially when the concentration of the interfering oil was large in comparison to the diesel oil. However, in nearly every instance in which a potential interference occurred (estimated at approximately 20 percent of all cases), both the EPA contract laboratory and the industry contract laboratory reported that an interference was present. Thus, from the testing done in the DPMP, EPA concluded that the thermal desorption/gas chromatography method was capable of determining the presence and concentration of diesel oil in the waste, and of identifying those situations in which an interference was present.

As a result, the details of the thermal desorption/gas chromatography test procedure and the results obtained were used to write EPA Method 1651 and to develop the quality control specifications for this method. The method included the requirement to use the diesel oil that was used for the pill for calibration of the gas chromatograph, if a sample of this oil was available. Method 1651 also provided criteria for identification of interferences, and suggested the use of gas chromatography combined with mass spectrometry (GCMS) for rigorous identification of diesel oil if an interference was suspected.

In 1990, EPA and the oil industry conducted a limited inter-laboratory validation study of Method 1651, using the EPA contract laboratory and industry contract laboratory that had participated in the DPMP, plus three industry laboratories that had either limited or no experience with the method. The results demonstrated that the inexperienced laboratories had difficulty in understanding the method. It was also noted that the EPA contract laboratory had difficulty with the thermal desorption apparatus. As a result, EPA agreed to modify Method 1651 to incorporate language clarifying some of the operational aspects of the method. EPA and the industry also agreed to investigate alternative extraction and analysis techniques, in order to simplify the operational portions of the method and enable better identification of diesel oil in the presence of interferences. However, because EPA does not want to further delay the regulation of pollutants discharged into the environment from offshore oil platforms, and because EPA believes that Method 1651 is adequate for determination of diesel oil in drilling fluids and drill cuttings when this method is followed, EPA is proposing this method for determination of diesel oil in drilling fluids and drill cuttings as published in the January 9, 1989 **Federal Register** (54 FR 634).

D. Radioactivitv of Produced Water

Within the past year, there has been much concern over the presence and levels of radium-226 (Ra ^{226}) and radium-228 (Ra ^{228}) in the produced water waste stream from oil and gas facilities. Both Ra ^{226} and Ra ^{228} are naturally occurring radioactive isotopes with half-lives of 1620 years and 5.7 years, respectively.

Uranium and thorium (present in deep geologic formations) undergo a decay series whereby radium is the first element in the decay series that is water soluble. The level of radium present in the formation water—which ultimately becomes the produced water—has been found to be proportional to the salinity of the formation water. There has also been some evidence which indicates that the radium-salinity relationship may vary depending on the source of the produced water, e.g., wells producing oil only or wells producing gas only.

There have been several studies conducted on produced waters from a range of locations, including offshore, coastal, and onshore facilities. The results of these studies have given preliminary information on the levels of radium in produced water across this range of locations. These results indicate that radium levels in the saline produced waters from the Gulf Coast region exceed proposed and existing radium discharge limits for other industries. Average open ocean surface waters contain 0.05 pCi/1 of Ra^{226} "while coastal waters generally do not contain natural levels of Ra^{226} much higher than 1 pCi/1.

In late 1986, API initiated a nationwide program to gather information on naturally occurring radioactive materials. This program involved voluntary sampling and analysis by oil and gas companies throughout the country. Specific sampling and analytical protocols were distributed to all the interested companies to ensure consistency of methodology. Companies were requested to perform radioactivity measurement for service equipment. Companies from twenty of the major oil and gas production states participated and a large volume of data were accumulated. The data were summarized in a final report from API entitled, "A National Survey on Naturally Occurring Radioactive Materials (NORM) in Petroleum Producing and Gas Processing Facilities" dated July 1, 1989. The report indicates that NORM activity levels showed wide variability, both geographically and among types of oil field equipment in the same geographic area. Although the data were not developed from a statistical plan, some trends have been noted. The geographic areas with the highest equipment readings for radioactivity are the entire Gulf Coast crescent (Florida panhandle to Brownsville, Texas), the northeast Texas crescent, southeast Illinois, and a few counties in southern Kansas. Gas processing equipment having the highest levels of radioactivity are reflux pumps, propane pumps and tanks, other pumps, and product lines. Water handling equipment in the production facilities category exhibits the greatest NORM activity levels.

Some findings of various other studies are summarized below:

• Battelle Laboratories completed a study for API in August, 1988 on the fate and effects of produced water discharges from four facilities in Louisiana coastal waters (three of which are covered by the offshore subcategory). The levels of Ra^{226} "and Ra^{226} combined were found to range anywhere from 605 to 1,215 pCi/1.

• Kramer and Reid in a 1984 publication, "The Occurrence and Behavior of Radium in Saline Formation Water of the U.S. Gulf Coast Region," reported measured amounts of total radium ranging from less than 0.2 pCi/1 in a produced water sample from a well in McAllen, Texas to 13,803 pCi/1 in a produced water sample from Vermillion Parish, Louisiana.

• In the Leeville oil field in LaFourche Parish, Louisiana, the produced waters were sampled and analyzed for Ra^{226} levels over a five year period. The levels of Ra^{226} varied from 16 pCi/1 to 397 pCi/1. Assuming that the average level in the produced water was about 280 pCi/1, over the five year sampling period, up to 1.76 Curies of Ra^{226} were discharged into surface waters with the produced water. (One picoCurie = 1×10^{-12} Curies.)

When elevated levels of up to 2,800 pCi/1 were discovered in the produced water discharges in Louisiana, the Louisiana Department of Environmental Quality (DEQ) issued an emergency rule which went into effect on February 20, 1989. This rule required a radioactivity measurement and toxicity tests to be performed on all existing produced water discharges that flow into the surface waters of the state (this includes offshore structures located in state waters).

The Louisiana DEQ has completed a preliminary analysis of the data received as a part of the sampling under the emergency rule. There were submissions of data from 450 sites discharging produced water into the surface waters of the state. The analyses for Ra^{226} and Ra^{228} were performed using the EPA Standard Method for drinking water. The results indicate that Ra^{226} and Ra^{228} are primarily found in the soluble phase and that one-third to one-half of the sites had levels of over 300 pCi/1. The maximum values were 930 pCi/1 of Ra^{226} and 928 pCi/1 of Ra^{228} while the overall average values were 158 pCi/1 of Ra^{226} and 164 pCi/1 of Ra^{228}.

As a part of the "three facility filtration study" conducted by the Agency in the summer of 1989, samples of the produced water waste stream were analyzed at different locations in the treatment system for Ra^{226} and Ra^{228}. Assessment of the raw data show effluent values after filtration of the produced water ranging from 10.6 to 213 pCi/1 Ra^{226} and 0 to 68 pCi/1 Ra^{228}, with very little if any removal by the filters.

Data bases are scattered and, for the most part, preliminary. This information is presented today to notice its availability and solicit additional data. EPA is concerned about the levels of radium in produced water and possible effects on human health and the environment. EPA intends to investigate the presence of radionuclides in produced water from facilities further offshore and the effects of radioactivity on the oceanic environment surrounding the platforms. Following receipt of any data as a result of today's notice and EPA's investigations, EPA intends to issue a Notice of Data Availability and will take all available information about radioactivity into account in developing final regulatory controls on produced water.

E. Other Studies

EPA and other agencies have performed studies regarding several other aspects of regulatory developing for the offshore oil and gas rulemaking effort. The titles and subjects of these studies are listed below. Descriptions of them and conclusions derived are discussed throughout the later sections of today's notice where appropriate.

1. "An Evaluation of Technical Exceptions for Brine Reinjection for the Offshore Oil and Gas Industry." An investigation into the feasibility of reinjection for produced waters.
2. "The EPA/API Diesel Pill Monitoring Program." An evaluation of the efficiency of diesel recovery practices after a diesel pill has been injected to free stuck pipe.
3. "Summary of Data Relating to Minor Discharges." An assimilation of available data on miscellaneous and minor offshore oil and gas discharges.
4. "Onshore Disposal of Offshore Drilling Waste—Capacity and Cost of Onshore Disposal Facilities." An assessment of land available and suitable for disposal of drilling wastes required as a result of a zero discharge requirement. Costs for on land disposal were also estimated.
5. "An Assessment of Produced Water Impacts to Low-Energy, Brackish Water Systems in Southeast Louisiana." A study by the Louisiana Department of Environmental Quality on the produced water impacts on low flow systems.
6. "Produced Water Effects on Coastal Environments." Minerals Management Service.

VIII. Waste Characterization

A. Produced Water and Drilling Wastes

Since the 1985 proposal, no new EPA field sampling data have been acquired relating to the general character of untreated produced waters and drilling wastes. Additional studies have been conducted on BPT treated produced waters (the "three-facility study"), on the appropriateness of the diesel oil discharge prohibition for drilling wastes, and on treatment technologies for drilling wastes (discussed in the 1988 notice). In addition, statistical evaluations of some previously submitted data were conducted. The results of the studies and evaluations and how they affect this rulemaking are discussed in later sections of today's notice.

As discussed in the 1985 proposal, the Agency also categorized the pollutants present in drilling fluids waste streams for purposes of determining appropriate limitations and standards. First, drilling fluids contain organics and metals that are priority toxic pollutants. These toxic pollutants include the cadmium and mercury and organic constituents of the diesel and mineral oils which may be added to drilling fluids. Also, the large number of specialty additives which may be used can contain priority toxic pollutants or nonconventional pollutants. BAT limitations and NSPS are being proposed to control the toxic and nonconventional pollutants. As discussed in greater detail in section IX, the Agency has considered options that include specific numeric limitations on cadmium and mercury, both in the stock barite and in the drilling wastes (fluids and cuttings); a prohibition on the discharge of diesel oil and free oil; and a toxicity limitation. Second, the oil and grease and total suspended solids present in drilling fluids are listed conventional pollutants subject to BCT limitations as well as NSPS. The prohibition on the discharge of free oil is the current BPT requirement; a static sheen test is proposed to implement this requirement. The Agency's approach to determining the appropriate guidelines and standards for drill cuttings is the same as that used for drilling fluids since the drilling fluids that adhere to the drill cuttings are the major concern.

The conventional pollutants oil and grease and total suspended solids will be subject to BCT limitations and NSPS.

As further discussed in the 1985 proposal, for purposes of determining appropriate guidelines and standards, the Agency categorized the pollutants present in produced water waste streams as follows. Produced water contains priority toxic organics and metals. BAT limitations and NSPS are being proposed to control these pollutants. Other chemicals, such as those contained in biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors which have not been identified as containing conventional or toxic pollutants, would be considered nonconventional pollutants subject to BAT limitations and NSPS. Any pollutants in these products which have been designated "toxic pollutants" would be subject to BAT and NSPS toxic limitations and standards. Finally, the oil and grease and total suspended solids present in produced water would be considered conventional pollutants subject to BCT and NSPS limitations, and possible indicator pollutants for the control of the toxic and nonconventional pollutants subject to BAT and NSPS.

B. Deck Drainage

Deck drainage results primarily from precipitation runoff, miscellaneous leakage and spills, and washdown of platform or drill ship decks, floors, and vessels. Virtually any material used at the site may find its way into the deck drainage system. Deck drainage often contains petroleum-based oils from miscellaneous spills and leakage of oils and other production chemicals used by the facility. It may also contain detergents from washdown operations and discarded or spilled drilling fluid components. The primary pollutant of concern in deck drainage wastes is oil and grease.

New data since the 1985 proposal were collected on deck drainage as part of a three-facility sampling program conducted during 1989. The Agency also recently reviewed extensive records of deck drainage collected in the 1970s by the API. Also, deck drainage information from platforms in Cook Inlet, Alaska, was reviewed.

The three-facility study sampled untreated deck drainage at two of the facilities. The API data review obtained influent to the deck drainage clean-up system and the actual discharge (effluent). Table 9 presents oil and grease loadings from deck drainage samples obtained from these studies and from the data contained in the 1985 proposal record. The Cook Inlet study acquired information about the compounds identified as hazardous chemicals found in deck drainage discharges. These include paraffins, sodium hydroxide, ethylene glycol, methanol, and isopropyl alcohol.

TABLE 9—DECK DRAINAGE CHARACTERISTICS

Study	Oil and grease (mg/l)	
	Influent	Effluent
Three-facility study	12-1,310[1].	NA[2].
API data	1-16,908	1-673.
1985 data	NA	5-183[3].

[1] Ranges of individual sample values

[2] Not analyzed

[3] Range of monthly averages of Discharge Monitoring Reports (DMRs) from the 1985 rulemaking record.

Both the Agency's data gathering efforts and API's survey information indicate the frequency, volume, and oil and grease content of deck drainage is highly variable. Oil and grease content of deck drainage may greatly exceed the BPT level discharge limits of produced water. The content and concentration of materials in deck drainage is highly dependent upon the operating and maintenance practices at the site, the flow of the deck wash, time between deck washings, and the point of time during a washing. For example, pollutant concentrations would be higher during the early stages of a deck washing episode than at the end of the episode.

For the reasons described above, the Agency has identified priority pollutant constituents of oil as pollutants of concern in deck drainage.

C. Produced Sand

Produced sand consists of particulate matter from the producing formation and other solids, such as scale, corrosion by-products, and paraffin. This material accumulates in production tubing, flowlines, and various oil and gas process vessels. This waste stream would also cover any residential sludges generated by chemical polymers used in the filtration portion of the produced water treatment system.

These solids must be removed periodically to restore oil and gas production and processing and/or avoid interruptions to those same activities. The sand is separated out from the produced water, washed with either water or solvent, and either discharged overboard with the produced water waste stream or stored in 55-gallon drums and transported to shore for disposal.

Produced sand generation is estimated at an average rate of 1 barrel per 2,000 barrels of oil. Actual volumes of sand production experienced by individual facilities depends upon the characteristics of the producing reservoir, sand control procedures utilized, and drawdowns experienced by the reservoir among other factors.

The primary pollutant of concern in produced sand wastes is oil and grease. The Agency collected new data on produced solids from three facilities in California and New Mexico during 1989. A review of individual sample results obtained from these facilities shows sand and solids associated with oil and gas production to have oil and grease contents as high as 132,000 ppm.

D. Well Treatment, Completion, and Workover Fluids

Well treatment fluids are used to improve the hydrocarbon recovery from productive reservoirs. These fluids move into the formation and either remain in the hole, return in diffused form with the produced water, or return as a discrete slug. Some of the more common well treatment fluids used include hydrofluoric acid; hydrochloric acid; ethylene diaminetetraacetic acid (EDTA); ammonium chloride; nitrogen; various alcohols and solvents such as methanol, xylene, and toluene; and numerous additives such as iron sequestering agents, corrosion inhibitors, surfactants, and fluid diverters. The acidic portion of well treatment fluids are generally spent on the formation and accompany the produced water phase. Other portions of the treatment fluids may become associated with the produced oil or gas phases.

Once production resumes, well treatment fluids are usually routed through the process equipment used to separate and treat the normal production stream. However, under current practice these fluids may also be captured in tanks at the surface and then disposed of by draining the water portion into the ocean or by transporting the fluid to onshore disposal sites. The volumes and constituents of well treatment fluids are well-specific, and the discharge frequency varies between locations. Well treatment discharges have been known to range from 12 bbls/day to 1,800 bbls/day.

EPA, during the three-facility study, sampled well treatment fluids at the coastal production facility. The well was acidized to enhance the productivity of the formation. The samples obtained of the treatment fluids prior to treatment showed an oil and grease level of 619 mg/l. The pH was 2.46. Other constituents present were aluminum, iron, magnesium, molybdenum, sodium, zinc, aniline, toluidine, and 2,4,5-trimethylaniline.

Completion and workover fluids are generally low solids fluids used to provide hydrostatic control and/or prevent formation damage. Typical well completion and workover fluid constituents may include hydroxyethyl cellulose, xanthan gum, hydroxypropyl guar, sodium polyacrylate, filtered seawater, calcium carbonate, calcium chloride, potassium chloride, and various corrosion inhibitors and biocides.

Completion and workover fluids currently may be collected and recycled, processed with the production stream and then discharged, or discharged directly into the ocean. The decision on whether to recycle or dispose of these fluids depends upon the cost and type of fluids utilized and various site specific factors. These fluids are more likely to be recycled if they are expensive or not contaminated with other materials. When these fluids are in use, discharges of completion and workover fluids have been estimated to range from 100 bbls/day to 1,300 bbls/day per facility.

Additional data since the 1985 proposal have also been obtained by the Cook Inlet study conducted by EPA's Region X on well treatment, workover, and completion fluids from structures in Alaska. This study lists the hazardous constituents associated with these fluids. These hazardous compounds include disodium salt of EDTA, quaternary polyamine, acetylenic acid, hydrochloric acid, hydrofluoric acid, isopropanol, and ethylene glycol. These compounds often comprise over 60 percent of the fluid composition.

A comparison was made between free oil detections (using the Static Sheen Test) and oil and grease levels in this Region X study. The data show that all well treatment, workover, or completion fluids did not exhibit a sheen, but oil and grease levels ranged from 0.1 to 1,420 mg/l.

Well treatment, completion, and workover fluids consist of acids, solvents, additives, polymers, or other low solids fluids. They are separate and distinct from drilling fluids. Oil and other organic constituents, which either are used in or surface with the well treatment, completion, or workover fluids, are the primary pollutants of concern.

E. Sanitary and Domestic Wastes

No additional data have been obtained on sanitary and domestic wastes since 1985.

F. Other Minor Wastes

In addition to those specific wastes for which effluent limitations are proposed, offshore exploration and production facilities discharge other wastewaters. Although believed to be minor, these wastes were nonetheless investigated. No control of these other wastes is being proposed by this notice, since these types of discharges from existing operations currently are being controlled by BPJ limits in NPDES permits. These sources are categorized into 15 "minor wastes" and are listed as follows:

(1) Desalinization unit discharge—wastewater associated with the process of creating fresh water from seawater.

(2) Blow-out preventer fluid—fluid used to actuate the hydraulic equipment on the blowout preventer.

(3) Laboratory wastes from drains.

(4) Uncontaminated ballast/bilge water (with oil and grease less than 30 mg/l)—seawater added or removed to maintain proper draft.

(5) Drilling fluid, drill cuttings, and cement at the sea floor that result from marine riser disconnect and well abandonment and plugging.

(6) Uncontaminated seawater including fire control and utility lift pumps excess water, excess seawater from pressure maintenance, water used in training and testing of fire protection personnel, pressure test water, and non-contact cooling water.

(7) Boiler blowdown—discharge from boilers necessary to minimize solids build-up in the boilers.

(8) Excess cement slurry that results from equipment washdown after a cementing operation.

(9) Diatomaceous earth filter media that are used to filter seawater or other authorized completion fluids.

(10) Waste from painting operations such as sandblast sand, paint chips, and paint spray.

(11) Uncontaminated fresh water such as air conditioning condensate and potable water.

(12) Material that may accidentally discharge during bulk transfer, such as cement materials, and drilling materials such as barite.

(13) Water flooding discharges—discharges associated with the treatment of seawater prior to its injection into a hydrocarbon-bearing formation to improve the flow of hydrocarbons from production wells. These discharges include strainer and filter backwash water, and treated water in excess of that required for injection.

(14) Test fluids—the discharge that would occur should hydrocarbons be located during exploratory drilling and tested for formation pressure and content.

(15) Source Water—Formation water used for water flooding (excess may be discharged).

Many of these wastes are low in volume and/or are infrequently discharged. In addition, the constituents in these wastes are mostly the same as those found in seawater or are inert material. Wastes containing the same constituents as the seawater include: Desalination unit discharge, uncontaminated ballast water, uncontaminated bilge water, and uncontaminated sea water. Minor waste sources that contain mostly inert material include source water and sand from enhanced recovery operations, boiler blowdown, and uncontaminated fresh water. The other minor wastes contain some degree of contaminants, but they are difficult to contain (such as waste from chipping, sanding, and painting operations, accidental releases during bulk transfer operations, and blow out preventer fluid), or their discharges are infrequent and expected to pose minor environmental impact (such as washdown after cementing operations; diatomaceous earth filter media from washing of filtration unit; and drilling fluids, cuttings, and cement at the sea floor resulting from marine riser disconnect and well abandonment and plugging).

The laboratory waste contains material used for sample analysis and the material being analyzed. The volume of this waste stream is relatively low and is not expected to pose significant environmental problems. However, freon may be present in laboratory waste. With the high volatility of freon, these wastes are not expected to remain in aqueous state for very long and are, therefore, not expected to be present in significant quantity. The Agency is discouraging the discharge of all chlorofluorocarbons, including foam, to the air or water media, and is proceeding under separate rulemaking with the identification and approval of alternate extraction solvents other than freon for the oil and grease analytical method.

IX. Parameters Selected for Regulation

A. Free Oil

A change in the test method of compliance for free oil was proposed in 1985. The proposal involved changing from a visual inspection after discharge to a "static sheen" test performed prior to discharge. The static sheen test would apply to certain options prohibiting the discharge of free oil. Affected waste streams are deck drainage, drilling fluids, drill cuttings, produced sand, and well treatment completion and workover fluids.

Based on comments received that the proposed test gave erroneous results, a modified test was also evaluated. Differences between the proposed test and the modified static sheen test are described in section VII. Below is a discussion of the reasons that the static sheen test was proposed in 1985.

Prior to the 1985 proposal, the compliance monitoring procedure required by BPT regulations was a visual inspection of the receiving water after discharge. However, since the intent of the limitation is to prohibit discharges containing free oil that will cause a sheen, the method of determining compliance should examine oil contamination prior to discharge. Also, concerns have been raised that the intent of the existing definition of "no discharge of free oil" may be violated too easily for the limitation to be effective. Violations which may result from intentional or unintentional actions include the use of emulsifiers or surfactants, discharges that occur under poor visibility conditions (i.e., at night or during stormy weather), and discharges into heavy seas, which are common on the outer continental shelf. Additionally, concerns have been expressed over the utility of the visual observation of the receiving water compliance monitoring procedure for certain discharges during ice conditions common in Alaskan operations. These include above-ice discharges where the receiving water would be covered with broken or solid ice, and below-ice discharges where the effluent stream would be obscured.

To address these monitoring problems, the Agency developed the static sheen test as an alternative compliance test. The alternative test continues the visual observation for sheen but provides for inspection before discharge using laboratory procedures. The test is conducted by adding samples of the effluent stream into a container in which the sample is mechanically mixed with a specific proportion of either seawater or fresh water, allowed to stand for a designated period of time, and then viewed for a sheen under controlled conditions.

Since the intent of a "no discharge of free oil" limitation is to prevent the occurrence of a sheen on the receiving water, the new test method will prevent the discharge of fluids that will cause such a sheen.

As proposed in 1985, free oil is being regulated under BAT and NSPS as an "indicator" pollutant for the control of priority pollutants (see section IX.B below). Free oil is being regulated under BCT as well. 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 to limit the creation of a visible sheen.

B. Diesel Oil

In 1985, EPA proposed a prohibition on the discharge of diesel oil in several of its regulatory options for drilling fluids and cuttings. EPA is not changing that proposal in today's notice. As proposed in 1985 (and included here for informational purposes), the prohibitions on free oil and diesel oil are intended to limit the oil content in drilling fluids and cuttings waste streams and thereby control the discharge of the priority toxics as well as conventional and nonconventional pollutants present in those oils. The prohibition on the discharge of oil is included in this option as an "indicator" of the toxic pollutants. 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. An indicator pollutant is one that, by its regulation, will provide control on discharges of one or more toxic pollutants. Diesel oil would be regulated as a nonconventional pollutant and an indicator because it contains toxic organic pollutants such as benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. The Agency's primary concern is controlling the priority pollutants in the oils, although these prohibitions also will serve to control nonconventional and conventional pollutants. The Agency selected the "indicator" approach as an alternative to establishing limitations on each of the specific toxic and nonconventional pollutants present in these oil-contaminated waste streams. The sampling and analysis data demonstrate that when the amount of oil is reduced in drilling fluid, the concentrations of priority pollutants and the overall toxicity of the fluids generally are reduced. The Agency has determined that the proposed controls on diesel oil will provide BAT-level control of the priority toxic and nonconventional pollutants present in drilling fluids. This method of toxic regulation is necessary because it is not economically or technical feasible to establish specific BAT limitations upon each of the toxic pollutants present in the drilling fluids. The technology basis for this limitation is product substitution.

C. Toxicity

In 1985, EPA proposed a limitation on toxicity as part of the regulatory options for drilling fluids and drill cuttings. EPA is not changing that proposal in this rulemaking. The limitation is set at 30,000 ppm and is based on the toxicity of the most toxic of eight generic drilling fluids in use at the time of the 1985 proposal. The toxicity limit is expressed as the concentration of the suspended particulate phase (SPP) of the drilling fluid that is lethal to 50 percent of *Mysidopsis bahia* exposed to that concentration of the SPP, i.e., the LC50 of the discharge.

The purpose of the LC50 toxicity limitation on the discharge of drilling fluids is to control the toxic constituents in drilling fluid discharges. While the limitations on free oil and diesel oil could significantly reduce the toxic pollutants present in drilling fluids, other additives, such as mineral oil or some of the numerous specialty additives, could greatly increase the toxicity of the drilling fluid, especially water-based drilling fluids. The toxicity is, in part, caused by the presence and concentration of priority pollutants. Thus, as proposed in 1985, the toxicity limitation will control toxic pollutants and effluent toxicity.

D. Cadmium and Mercury

The trace metals of concern in drilling fluids include cadmium, mercury, barium, zinc, lead, chromium, copper, and arsenic. One of the sources of barium and some of the other trace metals in drilling fluids is barite. Barite is mined from either bedded or vein deposits. Research has shown that the bedded deposits of barite are characterized by substantially lower concentrations of heavy metal contaminants such as cadmium and mercury (Kramer, J.R. et al, "Occurrence and Solubility of Trace Metals in Barite for Ocean Drilling Operations," Symposium—Research on Environmental Fate and Effects of Drilling Fluids and Cuttings, Sponsored by API, January 1980).

Barite may be contaminated with several metals of concern, including mercury, cadmium, zinc, lead, arsenic, as well as other substances. The Agency believes that by limiting the levels of cadmium and mercury in either the stock barite or the drilling fluid system discharge, concentrations of other related metals would be limited as well. EPA is proposing to regulate these two toxic metals in order to control the metals content of the barite component of any drilling fluid discharges. Cadmium and mercury are "toxic pollutants" subject to BAT and NSPS limitations.

The 1985 proposal included proposed effluent limitations of 1 mg/kg each of cadmium and mercury in the discharge of the whole drilling fluid on a dry weight basis. The proposed limitations would be maximum values. These effluent limitations are also included in some of the regulatory options proposed today.

In the 1988 notice, two alternative limitations for cadmium and mercury were presented. One established limits at 2.5 mg/kg cadmium and 1.5 mg/kg mercury in the whole drilling fluid. This was developed in response to comments regarding the cost and availability of barite "clean" enough to meet the 1 mg/kg cadmium and 1 mg/kg mercury limitations. The 2.5/1.5 mg/kg cadmium/mercury limitations were suggested based on the use of barite containing no more than 5 mg/kg cadmium and 3 mg/kg mercury which, commenters declared, was available in adequate supply. The 2.5 mg/kg cadmium and 1.5 mg/kg mercury limitations were derived using an assumption that barite is diluted by 50 percent or more in the drilling fluid. In the 1988 notice, the Agency also presented the option of limiting cadmium and mercury at 5 mg/kg and 3 mg/kg, respectively, in the stock barite instead of setting an effluent limitation in the drilling fluid.

The limitations for cadmium and mercury of 2.5 and 1.5 mg/kg, respectively, in the drilling fluid are no longer considered appropriate because insufficient support exists for the assumption that a 50 percent dilution occurs once barite is mixed with drilling fluids.

Based on additional information since the 1988 notice, today's proposal further presents three alternatives for cadmium and mercury limitations: (1) Maintaining the 1985 proposed discharge limitations of 1 mg/kg cadmium and 1 mg/kg mercury each in the drilling fluid, (2) limitations based on barite composition of 5.0 mg/kg cadmium and 3.0 mg/kg mercury as included in the 1988 notice, and (3) limitations of 3.0 mg/kg of cadmium and 1.0 mg/kg of mercury based on stock barite composition. All of these limitations would be a maximum (no single sample to exceed) value.

Recent information to evaluate EPA's current alternatives for metals limitations comes from data compiled during a joint effort by EPA and API. The current version of this database, "API—USEPA Metals Database for Metals Content in Drilling Muds—Drill Cuttings/Formations—Barites—Sediments," is from April 1990. This database contains data sets, from all studies currently known to EPA and API, on the metals content of drilling fluids and drill cuttings.

Analysis of a select set of data sources from this data base, considered appropriate for the following statistical analyses, was performed to determine compliance rates with each set of limitations. All of the data sets show passing rates to some degree for all limitation options. The limitations for 1 mg/kg cadmium and 1 mg/kg mercury in the drilling fluids are the most stringent; however, 100 percent compliance was achieved by the four samples measured in EPA's Region IX. This is probably due to the fact that some of the recent Region IX individual permits have limitations of 2 mg/kg cadmium and 1 mg/kg mercury in the barite composition. Region X, which includes in its general permits limitations of 3/1 mg/kg cadmium and mercury, respectively, in barite composition, shows a 67 percent compliance rate for 1/1 mg/kg cadmium/mercury limit in drilling fluids. Data from Gulf of Mexico facilities show a lower percentage of compliance; however, there are currently no metals limitations in the Region VI general permit. Region VI is preparing limitations for proposal in response to the decision of the United States Court of Appeals for the Ninth Circuit in *NRDC* v. *EPA*, 863 F.2d 1420, 1432–33 (9th Cir. 1988). For comparative purposes, EPA is evaluating in its regulatory options, discussed later in section XII, the most stringent cadmium and mercury limitations (1/1 mg/kg in the fluids) and the least stringent option (the 5/3 mg/kg cadmium and mercury limitations in the barite composition).

In response to comments regarding concern over availability of barite supplies, EPA investigated the adequacy of available foreign and domestic supplies of barite that meet the proposed cadmium and mercury limitations of either 1/1 mg/kg in the fluids or 5/3 mg/kg in barite. This investigation compared foreign and domestic barite supplies, with compositions adequate to meet the proposed limitation, to the projected industrial demand. The conclusion was that supplies are adequate to meet the needs of offshore drilling operations if either limitation were in place.

In addition to noncompliance being caused by the use of barite with high cadmium and mercury content, commenters stated that the presence of cadmium in the formation itself could cause noncompliance with limitations applied at the drilling waste discharge point. In particular, an analysis of API's 15 Rig Study (discussed later in section XIII.A.2) estimates cadmium formation contribution to drilling fluids as high as 79 percent. However, this report is based on certain assumptions for which EPA is also requesting comment. If, however, the metals limitations could not be met for this or any other reason, then barging would be necessary for land disposal.

The proposed BAT and NSPS limitations on cadmium and mercury would also serve to control the concentration of other toxic metals in the drilling waste discharges. The same metals data base study referenced above concluded that concentrations of other toxic metals are positively correlated with concentrations of cadmium and mercury. This information supports EPA's proposal in 1985 to consider limiting mercury and cadmium in order to control other toxic metals.

E. Oil Content

The 1985 proposal included an option for regulating oil content for drill cuttings. However, this option was rejected in 1985 because EPA believed that establishing an oil content limitation on drill cuttings was redundant since the prohibition on the discharge of free oil appeared to be a more stringent limitation. Data on the performance of cuttings washer technologies showed residual oil content levels near 10 percent by weight. Data on the visual sheen test (used then for the free oil discharge limitation) showed compliance with this limitation required levels of oil content to be reduced to less than 1 percent.

The Agency continued to study technologies for controlling the oil content of drilling wastes. and presented its findings in the 1988 notice. This study was expanded to explore the applicability of an oil content limit to drilling fluids as well as to drill cuttings. A number of conclusions evolved from this study which EPA reiterates below.

1. Drilling Fluids

An oil content limit for drilling fluids based on the technologies studied is not appropriate because the volume of fluids at the end of the drilling that would require treatment is much greater than the technologies evaluated were capable of handling (with regard to treatment rate). In addition, space is insufficient on platforms to accommodate these kinds of drilling volumes of fluids that must be stored in preparation for processing at rates acceptable by the technologies.

2. Drill Cuttings

The 1988 notice discussed technologies for controlling the oil content of drilling wastes with respect to both oil-based and water-based systems. Oil content of untreated drill cuttings associated with oil-based drilling fluids was estimated at 20 percent oil by weight. Untreated drill cuttings from water-based drilling fluids to which oil had been added for spotting or lubricity were estimated to contain 1 percent oil by weight. Data on performance of thermal distillation showed that oil content for drill cuttings (associated with either water- or oil-based fluids) could be reduced to 1 percent by weight. For solvent extraction, reductions were attained to 0.3 percent by weight. Thus, it was stated that drill cuttings from water-based systems to which oil had been added for spotting or lubricity would not require treatment to comply with an oil content limit of 1 percent by weight.

EPA continues to believe that reductions even to 1 percent in water-based systems are redundant. The free oil limitation already results in compliance to this level. In addition, the limitation on diesel oil and toxicity adequately covers toxic pollutants associated with oil content of drilling wastes. Reductions of another 0.7 percent exhibited by the solvent extraction technology do not compensate for the disadvantages in using this system. As discussed in the 1988 notice, the potential for losses of chlorofluorocarbon-type solvents to the atmosphere are a major concern for solvent extraction.

In addition, EPA is not in the position to develop limitations based on the thermal distillation technologies because this technology has not been demonstrated either by full-scale or pilot testing to be capable of operating at offshore facilities and due to safety concerns regarding fire hazards. EPA is not prohibiting the use of these technologies, as it remains an operator's decision to choose a preferred compliance method. However, federally applicable limitations based on these technologies are not appropriate at this time.

F. Oil and Grease

The most obvious pollutant of concern for produced waters is oil and grease. This pollutant is already regulated under BPT. EPA is proposing certain options that will either equal or be more stringent than the BPT oil and grease limits for produced water. Oil and grease is a conventional pollutant subject to BCT limitations as well as NSPS. EPA is also limiting oil and grease under BAT as an indicator pollutant for certain toxic and metal priority pollutants as well as nonconventional pollutants.

EPA believes it is appropriate to regulate oil and grease under BAT as an indicator for other organic and metal toxic pollutant removals because the technologies used to remove oil and grease also remove additional pollutants of concern. As discussed in section X, membrane and granular media filtration along with chemical polymer addition form the basis for certain regulatory options. Granular media filtration, while it primarily removes suspended insoluble matter, does achieve a degree of organic and metal removal as well. Membrane filtration removes considerably more of the soluble hydrocarbon constituents.

Analysis of data from the three-facility study on performance of granular media filtration showed significant reductions for total suspended solids and oil and grease. Significant reductions in the metals aluminum, calcium, iron, magnesium, and manganese were also achieved. Additionally, significant reductions were achieved in 2-propanone. The Agency believes other compounds would show significant reductions if a larger number of samples had been collected.

G. Residual Chlorine and Floating Solids

NSPS limitations on residual chlorine and floating solids were proposed in 1985 for sanitary wastes as being equal to BPT. The presence of residual chlorine gives positive indication that fecal coliform does not exist. BCT and NSPS were proposed in 1985 for domestic wastes as prohibiting the discharge of floating solids. Today's notice does not change that 1985 proposal. No BAT limits were proposed for these parameters because no toxic or nonconventional pollutants of concern were identified in sanitary or domestic wastes.

H. Foam

The general permit for the Gulf of Mexico prohibits the discharge of visible foam in other than trace amounts for all wastes. Limitations on foam are intended to control discharges that include detergents. EPA believes this is a particularly appropriate pollutant to limit for domestic wastes. The sources of domestic wastes include laundries, galleys, showers, safety shower and eyewash stations, hand wash stations, and fish cleaning stations. Detergents are an inherent nature of this waste. Foam is a nonconventional pollutant proposed for NSPS.

X. Control and Treatment Technologies

A. Current Practice

The BPT regulations established for the offshore subcategory are focused primarily on the control of free oil and the oil and grease content of waste streams that are discharged to the ocean. The information concerning current practice, and discussed in this section, was obtained both for the 1979 rulemaking and the 1985 proposal. The only change in the data obtained for these previous efforts and discussed at this time is an updated statistical analysis on sample results for BPT produced water effluents.

Drilling Fluids

The current BPT regulation for drilling fluids prohibits the discharge of free oil. In general, water-based drilling fluids are discharged directly to the ocean, because they do not cause a sheen unless the fluids have been contaminated with oil. In the case of water-based drilling fluids to which oil has been added for spotting or lubricity, current BPT regulations prohibit their discharge if they cause a sheen. Compliance with the prohibition of free oil is achieved by transportation of the spent fluids to shore for land disposal, or treatment to recover the oil and land disposal of the residual solids. When oil-based drilling fluids are used offshore, the fluids are not discharged, but are returned to shore for reconditioning and reuse or disposal.

In addition to the requirement for no discharge of free oil, current NPDES permits require compliance with toxicity limits and prohibit the discharge of diesel oil. Failure, or anticipated failure, of the drilling fluid system to meet the toxicity limit or diesel oil discharge prohibition also causes the spent fluids to be returned to shore for disposal.

2. Drill Cuttings

The cuttings are segregated from the drilling fluid with a shale shaker and associated separation equipment. Existing practices for drill cuttings based on the same BPT requirement as drilling fluids (i.e., no free oil) and current permits for the handling of drill cuttings include: (1) On-site disposal of drill cuttings with an oil content that does not cause a sheen on the receiving water; (2) washing of drill cuttings that contain oil at a level that would cause a sheen so that they may be discharged on-site to the receiving water; and (3) transportation to shore for treatment and/or land disposal.

3. Produced Water

Existing technologies for the on-site removal of oil and grease from produced water discharges include gas flotation, gravity separation, chemical addition to assist oil-water separation, and, less often, parallel plate coalescers and loose or fibrous media filtration. On-site disposal methods from offshore production platforms include free fall discharge to the ocean, discharge below the water surface, and, at times, reinjection into a subsurface formation. As an alternative, some production sites transport produced fluids by pipeline to shore facilities for oil-water separation and disposal.

The removal of priority pollutants in BPT treatment systems is minimal. While the sampling data indicated quantifiable reductions of naphthalene, lead, and ethylbenzene by the BPT treatment (i.e., by oil-water separator technology), the presence of significant levels of priority pollutants (e.g., naphthalene and ethylbenzene) in all effluent samples demonstrates the limitations of such treatment technologies.

Reinjection is a disposal technique for injection of produced water into a subsurface formation. When reinjection is used for disposal purposes only, it is possible that the receiving formation may not be the same formation from which produced fluids were extracted. Secondary recovery or pressure maintenance (water flooding) is a practice under which produced water (or other fluids) is injected into a producing formation to enhance recovery of hydrocarbons. Reinjection of produced water into a producing formation may serve both purposes, i.e., disposal of produced water and enhanced recovery of hydrocarbons.

Treatment of produced water (or other fluids) prior to injection may be necessary, and such treatment may include oil-water separation and/or filtration to minimize plugging of the receiving formation. (Oil-water separation also serves for recovery of oil as a commercial product.) Also, biocides, corrosion inhibitors and sequestering agents (or ionic bonding agents) may be added to the water to reduce or prevent scaling and corrosion of the injection equipment. The type and amount of treatment depends primarily on the properties of the receiving formation and characteristics of the fluids being injected.

The concentration of toxic pollutants in BPT treated produced waters was investigated during an extensive sampling and analysis effort performed at 30 platforms prior to the 1985 proposal. Selected conventional and nonconventional pollutants were also analyzed.

EPA updated the statistical analysis of results from the 30 platform study in 1989 in order to correct inadequacies in the consideration of detection limits, duplicate samples, and sample exclusion. The results of the analysis do not affect this or previously proposed regulations. Data simply are recalculated in an effort to more accurately estimate BPT effluent pollutant loadings. The results of the analysis show flow-weighted oil and grease effluents averaging 89.8 mg/l. The priority organics most often present in significant amounts were benzene, bis (2-ethylhexyl) phthalate, ethylbenzene, naphthalene, phenol, toluene, and 2,4-dimethylphenol. Priority metals present were cadmium, copper, lead, nickel, silver, and zinc.

4. Deck Drainage

The current BPT requirement for deck drainage prohibits the discharge of free oil (i.e., sheen). Under current practices, deck drainage is either collected and treated separately for oil removal by gravity separation or is handled by the produced water treatment system before discharge.

A commonly used treatment technology for removal of free oil from deck drainage is oil-water separation. This is typically a gravity separation process, whereby the waste stream is collected and diverted to a tank or other vessel. Adequate volume is provided in the vessel to provide sufficient detention time for the free oil and water to separate. The oil layer is then removed by decanting or skimming and returned to the production process, and the water layer drawn off for discharge. The majority of platforms in the Gulf of Mexico and offshore California use gravity separation technology on the platform for treatment of deck drainage. Some California platforms pipe deck drainage along with produced water to shore for treatment. Alaska operations typically treat deck drainage wastes on the platform.

Deck drainage treatment systems and systems that handle both produced water and deck drainage operate much more efficiently when good housekeeping and maintenance practices are employed. These include separation of crankcase oils from the deck drainage collection system, minimization of spills, discriminate use of detergents, and preventing drilling fluids from entering the deck drainage collection system.

5. Produced Sand

Produced sand wastes are either transported to shore for treatment and/or disposal or are treated by water and/or solvent washes for oil removal to prevent the discharge of free oil and discharged to the ocean.

6. Well Treatment Fluids

The current BPT requirement for well treatment fluids prohibits the discharge of free oil (i.e., sheen). Well treatment fluids are used to enhance production from oil and gas bearing zones. These fluids are injected into the producing formation as a slug, and some of the fluids remain in the hole. Under current practices, well treatment fluids that resurface are not treated as discrete sources but are considered to be mixed with the oil, gas, and water produced from the formation. Therefore, separate processing equipment is not provided for well treatment fluids. The spent acid, or other treatment fluid, moves through the normal processing system. After separation, well treatment fluids may end up with the oil, gas, or water phase depending upon the type of fluid. For instance, solvents such as xylene or toluene will normally become part of the oil stream while nitrogen used as a displacement fluid will separate with the gas, and spent acid will be discharged with the produced water. Minor volumes of well treatment fluids may also be disposed of through the deck drainage system as a result of leakage and washdown operations.

Normally all of the well treatment fluids brought to the location are utilized. However, occasionally a portion of the treatment is not used. If this occurs, the service company supplying the fluids usually retains it for reuse or disposal.

7. Completion and Workover Fluids

Completion and workover fluids are generally low solids fluids used to provide hydrostatic control and/or prevent formation damage. Usually, these fluids are handled by processing through the normal production system, capturing for reuse or disposal, or direct discharge into the ocean. This decision is dependent upon the type of fluid, its cost, and the facilities available.

8. Sanitary Wastes

Sanitary wastes from offshore facilities are usually treated at the source by physical/chemical systems. Facilities that are manned continuously by ten or more people are required by current BPT regulations to maintain a residual chlorine concentration in the sanitary waste discharge at a minimum of 1 mg/l for disinfection purposes and to maintain the residual chlorine as close to this level as possible. This chlorine residual is achieved by introducing chlorine in flow dependent amounts. Chlorine is either supplied from commercial sources or may be electrocatalytically generated from seawater. This chlorine requirement is based upon the use of U.S. Coast Guard-approved marine sanitation devices (described in 40 CFR part 140) and is required by the BPT regulations.

9. Domestic Wastes

Current permits require domestic wastes at all facilities to be free of floating solids. This is accomplished by the use of shredders or screening devices. In addition, a general permit controls the discharge of foam.

B. Additional Technologies Considered

The Agency has investigated additional control and treatment technologies in the formulation of today's proposed regulations. Some of these technologies were considered in the 1985 proposal and some in the 1988 notice. Additional technologies, particularly for produced waters, have been evaluated since the 1988 notice. These technologies, as well as those previously considered technologies no longer deemed appropriate for use in this regulation, are discussed below.

1. Drilling Fluids

a. Product Substitution. Product substitution was one of three technology bases considered for drilling fluids and drill cuttings in 1985. Product substitution is a method to achieve the discharge limitations on free oil, diesel oil, cadmium, mercury, and toxicity. Some typical methods for compliance with these limitations are: (1) Use of water-based drilling fluids; (2) use of product substitutes such as low toxicity mineral oils for spotting and lubricity purposes; (3) use of low-toxicity specialty additives, and (4) use of barite with low toxic metals content. EPA's preferred option for control of drilling fluids in the 1985 proposal was based on product substitution. Comments expressed concern over the diesel oil discharge prohibition and the fact that it would force the use of mineral oil.

Studies performed by EPA and industry (53 FR 41356; 51 FR 29600; 52 FR 3646) support EPA's conclusions that: (1) Mineral oil is in common use by operators in the Gulf of Mexico and Alaska, as well as internationally; (2) mineral oil is an available alternative to the use of diesel oil; and (3) success rates (for spotting purposes) comparable to those with diesel oil can be achieved with mineral oil.

Other comments submitted after the 1985 proposal suggested allowing the discharge of diesel oil when it is used as a spotting fluid. In response to this, EPA also conducted a study to determine the recovery capability of diesel oil when using it as a spotting fluid. This study, known as the "Diesel Pill Monitoring Program" (DPMP) and described in the 1988 notice, supported EPA's conclusions that pill recovery techniques implemented during the program do not result in recovery of sufficient amounts of the diesel pill and reduction of drilling fluids and cuttings toxicity to acceptable levels for discharge of bulk systems. Systems for approximately one-half of all wells in the DPMP contained residual diesel levels between 1–5 percent by weight after introduction of a diesel pill and subsequent pill recovery efforts. In addition, systems for approximately 80 percent of the DPMP wells failed the 30,000 ppm LC50 toxicity level after pill recovery. Almost half that number (40 percent of the total) of the DPMP wells had water-based systems that contained residual diesel following pill recovery and showed LC50 values of less than (more toxic than) 5,000 ppm.

For the reasons discussed above, the Agency believes that its proposed prohibition on the discharge of drilling fluid and drill cuttings which have been contaminated with diesel oil is appropriate for the BAT and NSPS levels of control for waterbased drilling fluids. The pollutant "diesel oil" is being used as an indicator of the listed toxic pollutants present in diesel oil. The technology basis for the prohibition on the discharge of diesel oil in drilling fluids and drill cuttings is substitution of mineral oil for diesel oil in the fluid system and for lubricity and spotting purposes, and the barging and land treatment and/or disposal of drilling fluids and cuttings which fail the sheen test or toxicity limits. Such a prohibition on the discharge of diesel oil contaminated drilling fluids and drill cuttings was upheld by the United States Court of Appeals for the Fifth Circuit, *American Petroleum Institute* v. *EPA*, 858 F.2d 261, 263–66, clarified and rehearing denied, 864 F.2d 1156 (5th Cir. 1988) (Bering and Beaufort Seas general permits).

b. Zero Discharge. EPA also considered zero discharge of drilling fluids and drill cuttings in 1985. This option is based upon the transport of spent drilling wastes to shore for recovery, reconditioning for reuse, or land disposal. EPA rejected this option in 1985 because the costs of barging and land disposal were too high. The availability of landfill sites was also a concern.

Since the 1985 proposal, EPA has re-evaluated this option and determined that barging drilling wastes is technically and economically feasible. In addition, in response to both industry and Agency concerns, EPA has studied the availability of land disposal capacity ("Onshore Disposal of Offshore Drilling Waste—Capacity and Cost of Onshore Disposal Facilities," ERC Environmental and Energy Services Co. for U.S. EPA, January 1991). The study concluded that enough land is projected to be available to support the disposal requirements for this option. Yet, while available disposal sites exist, EPA has concerns over the use of large land areas for the disposal of drilling wastes. In addition, the increased barging and handling operations, both on platforms and at dock facilities, require a significant increase in fuel use and result in large amounts of air pollutant emissions. Thus, this option is considered in today's proposal for all structures, and then, to accommodate the non-water quality environmental impact concerns, for shallow water structures only and for structures located 4 miles or less from shore.

c. Clearinghouse Approach. 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 with constituents that are less environmentally harmful than many that are available. The generic drilling fluid concept was developed in 1978 when the Agency instituted a joint testing program for various formulations for operations in the Atlantic Ocean lease sale areas. EPA Region II 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. The selected generic fluids demonstrated relatively low toxicity in the referenced bioassay program. 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.

In the 1985 proposal, Option 2—Clearinghouse Approach discussed the establishment of a national clearinghouse to be administered by EPA. Under this option, the Agency would serve as 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 regulation (50 FR 34608).

EPA Region X later issued several NPDES general permits (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)) that used the generic fluids concept and authorized the discharge of certain additives without bioassay testing in the discharged fluids upon discharge. In all of these permits, Region X listed generic fluids and additives authorized without further bioassay requirements in a table in the permit. However, operators required specialty additives that were not authorized in the Region X permit. Lacking any method to precisely determine the cumulative toxicity of generic fluids discharge with additives not in the permits, Region X applied the concept of additivity to estimate the cumulative toxicity of fluids and additives.

In the 1985 proposal, the Agency 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 (50 FR 34592). Although the Agency has received many comments in favor of a clearinghouse approach to fluids/additive discharge authorization, several important reasons remain that support rejection of this regulatory option.

First, the Agency's NPDES permitting program (sec. 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, 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 system can be effective on a small scale, the Agency has reservations regarding a nationwide program. The success of the Region X 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 X offshore area is 12 per year in the unconstrained scenario). A national clearinghouse program involving almost 1,000 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 continues to reject the clearinghouse option as a component of nationally applicable regulations; however, this would not necessarily preclude the use of a clearinghouse approach in permits as a means of implementing toxicity limits in these regulations, if appropriate.

d. Other technologies. Thermal distillation and solvent extraction were discussed both in the 1985 proposal, the 1988 notice and a proposed general demonstration permit issued by Region VI on October 16, 1989 (54 FR 42335). The operation of these technologies results in a reduction of oil content in drilling wastes. Thus, the regulated parameter associated with these technologies would be oil content. EPA rejected these technologies as a basis for regulatory control on the general premise that limitations on the other parameters, diesel oil, free oil, and toxicity are sufficient to reduce toxics from drilling wastes. In addition, thermal distillation is no longer being considered as an option because it has not been adequately demonstrated at the present time as a viable technology for use on an offshore platform. Solvent extraction is not considered because the Agency remains concerned (as stated in the 1988 notice) over the potential losses of chlorofluorocarbon-type solvents from these processes to the atmosphere.

Incineration was discussed in the 1985 proposal but rejected due to equipment size, energy costs, and possible fire hazards associated with this process. Some of these technologies may be applicable for onshore treatment of drilling fluids and cuttings that are barged and transported to central locations for reconditioning, treatment, and/or disposal.

2. Drill Cuttings

EPA is considering requirements for drill cuttings based on the same treatment/disposal methods described in the previous section on drilling fluids. Those methods involve the use of certain types of drilling fluids which would be mixed with the drill cuttings extracted from the drilled hole (bore hole). The use of water-based drilling fluids, mineral oil instead of diesel oil for spotting or lubricity, barite with low cadmium and mercury content, or on-land disposal are the basis for meeting the proposed requirements. The same technologies considered in the 1985 proposal and 1988 notice, but rejected for drilling fluids, were also rejected for cuttings.

3. Produced Water

EPA evaluated each of the following treatment technologies in addition to the control technology. These technologies were considered for implementation at offshore facilities and onshore where produced water is piped to shore for treatment.

a. Improved Performance of BPT Technology. The 1985 proposal evaluated the costs and feasibility of improved performance of existing BPT treatment technologies to determine whether more stringent effluent limitations for oil and grease would be appropriate. This approach would be based on improved operation and maintenance of existing BPT treatment equipment (e.g., gas flotation, coalescers, gravity oil separation), more operator attention to treatment system operation, and possibly re-sizing of certain treatment system components for better treatment efficiency.

When discussed in the 1985 proposal, statistical analysis of effluent data from facilities sampled during the Agency's 30-platform survey showed that an oil and grease effluent limitation of 59 mg/l maximum (i.e., no single sample to exceed) could be achieved through improved performance of BPT technology. Problems with the original analysis included lack of documentation for the platforms selected as examples of improved performance for BPT and the treatment of samples split for quality control of lab results as if they were independent samples from the wastewater treatment process.

This re-analysis shows that the appropriate limitations are 38 mg/l as a daily maximum value not to be exceeded in any single daily composite analysis and 27 mg/l as a monthly average value not to be exceeded. A daily composite sample consists of four grab samples taken at different times throughout the day. These potential limitations can be compared to current BPT limitations of 72 mg/l daily maximum and 48 mg/l monthly average. The potential limitations are calculated based on the same number of grab samples per day as current limitations. The data used to determine the potential limitations were obtained at platforms whose selection is documented and where split sample results are averaged prior to capability analysis for the effluent.

The 1985 proposal, in its options selection process, chose this option for all deep water facilities, and for all gas facilities regardless of water depth. This option, although still being considered, is no longer a preferred option for this rulemaking because of the problems identified with the performance evaluation.

b. Filtration. In the 1985 proposal, EPA discussed filtration as both an add-on technology to BPT and as pretreatment for reinjection. The primary purpose of filtration is to remove suspended matter, including insoluble oils, from produced water. Additional removal of soluble pollutants can also be achieved, but it is not as significant as the reduction of conventional pollutants such as suspended solids and oil and grease. The 1985 proposal discussed the granular media technology as an option for treatment of produced waters, but only for BCT and NSPS, since significant reduction in soluble organics or metals was not evident. For NSPS, the proposal included, as an option, limitations for both TSS and oil and grease of 20 mg/l monthly average and 30 mg/l daily maximum. However, this option was rejected in the 1985 proposal.

After the 1985 proposal, EPA continued to evaluate filtration technologies. A granular media filtration study (known as the "three-facility study" and discussed in section VII, Data Gathering) was conducted to acquire additional data on the performance of this technology. In addition, the Agency has been supplied with information on a membrane filtration technology and its application to treating oil and gas wastes, specifically by the use of ceramic membranes to treat produced water. Membrane filtration is more effective in removing constituents of wastewaters that are normally referred to as soluble and are more resistant to physical separation by filters. However, the three facility study showed significant removals of hydrocarbons from granular media filtration as well. Today's notice presents additional filtration performance data, both for granular and membrane filters, upon which regulatory options are based.

Granular media filtration involves the passage of water through a bed of filter media with resulting deposition of solids. The filter media can be single, dual, or multi-media beds. When the ability of the bed to remove suspended solids becomes impaired, cleaning through backwashing is necessary to restore operating head and effluent quality. In many cases, filters are operated in conjunction with chemical polymers which are added to increase removal efficiencies. There are a number of variations in filter design. These include (1) the direction of flow: down-flow, up-flow, or bi-flow; (2) types of filter beds: single, dual, or multi-media; (3) the driving force: gravity or pressure; and (4) the method of flowrate control: constant-rate or variable-declining-rate.

Filtration is widely used for produced water treatment prior to reinjection. The filters are used for the removal of suspended solids and are usually preceded by chemical pretreatment and/or oil removal treatment systems. EPA has investigated this technology, not only as a pretreatment to reinjection but as an add-on system to BPT prior to discharge.

During the three-facility filtration study, influent and effluent samples were taken from three granular media filtration units used as a means of pretreatment prior to reinjection. One of the facilities was an onshore operation in New Mexico, one was an offshore operation off of California, and the third facility was a California coastal production facility (gravel island) which treated and reinjected produced water.

The gravel island facility generated approximately 18,000 barrels per day of produced water to be treated. However, in order that there be sufficient water for reinjection purposes, approximately 5,000 barrels per day of fresh water were added to the produced water before filtration, requiring the filters to handle approximately 24,000 barrels per day. Prior to the addition of fresh water at the filtration step, skim tanks receive all the produced water from the oil field after the initial removal of oils from each group of production facilities. The skim tanks remove additional oil by gravity before treatment. The fresh water is then combined with the produced water along with chemicals consisting of a corrosion inhibitor, a coagulant, and a flocculent aid prior to the filters. These combined waters are pumped to three sand filters. Normally, two filters are operating in an upflow direction while the third either is on standby or backwashing.

Operation of the other two facilities is somewhat similar except that the New Mexico facility does not employ gas flotation, and the offshore facility does not employ chemical addition prior to filtration and subsequent reinjection.

EPA statistically analyzed the data from this study to determine effluent levels achievable from granular-media filtration technology. Data from two of the three facilities were determined to reflect adequate treatment beyond BPT. The third facility had poor performance due to the absence of chemical addition prior to filtration.

Effluent limits for oil and grease, based on granular media filtration, are calculated from concentration data collected during the three facility study. The daily maximum of 29 mg/l is the estimated 99th percentile for daily composite samples. Each daily composite value is the average of chemical analytical results from 12 grab samples taken at two hour intervals throughout the day. The monthly average of 16 mg/l is the estimated 95th percentile for the average of four daily composite samples. For comparison purposes, effluent limitations on the same four grab sample per day basis as current BPT limitations are 32 mg/l as a daily maximum and 17 mg/l as a monthly average.

The use of membrane filters to treat produced water from oil and gas extraction activities is a relatively new application for this process. However, membrane technology has been applied in a number of industries for many years. Ceramic (membrane) filters are used to separate oil, bacteria, solids, and emulsified material from water in several industrial applications, including the dairy, beverage, and pharmaceutical industries. In the case of produced water, the waste stream is first chemically pretreated to produce discrete solids that flocculate a portion of the emulsified oil and suspended solids. The pretreated water is then passed through ceramic filters which consist of multichannel, cylindrical passages in a ceramic block and one or two layers of alumina ceramic material.

As the wastewater passes through the cylindrical passages, a portion of the wastewater moves though the ceramic material to the outside of the filter, leaving a relatively small volume of concentrated retenate behind. The retenate is recycled to the pretreatment process where a blowdown periodically occurs. The membranes may require periodic chemical cleaning to remove foulants, in addition to the operational back-pulsing which is used to continuously clean the passages in the ceramic block. The units are tolerant of high temperatures and pressures, and, due to their compact size, are suited for use on offshore oil and gas platforms.

At the present time, the Agency knows of one membrane unit operating in the Gulf of Mexico and three additional units under construction or in start-up phase in the Gulf of Mexico, Canada and the North Sea. The Agency has been supplied with information concerning the ceramic membrane filtration unit operating in the Gulf of Mexico and data from pilot scale tests conducted in Kansas, Alaska, California, Canada, the Gulf of Mexico, and the North Sea. Table 10 shows the results of some of these tests. The tests show that the performance of ceramic membrane technology is capable of giving a range of effluent values of oil and grease as low as 1 to 9 mg/l even when influent levels are much greater than the current BPT levels.

TABLE 10.—MEMBRANE SEPARATION PERFORMANCE: RANGE OF CONCENTRATION RESULTS BY GEOGRAPHIC LOCATION

Location	Test scale	Character of feed	Oil and grease (mg/l)		Total suspended solids (mg/l)	
			Infl.	Effl.	Infl.	Effl.
North Sea	Bench	Spiked raw produced water	50,000	4	N/A	N/A
Louisiana (onshore)	Pilot	Effluent from separator/chemical addition	166–582	<8.8	N/A	N/A
Gulf of Mexico	Full-scale	Chemical addition/water precipitator	27–108	<5.0	100–290	<1
Gulf of Mexico	Pilot	Chemical addition/water precipitator/parallel plate coalescers.	105–574	2–5	73–350	<1

Membrane filtration may be utilized as add-on technology or as replacement equipment for present produced water treatment technologies and shows potential for more efficient removals of the organic compounds than the BPT technology and granular filtration technology.

The effluent limits based on membrane filtration were developed from data with an assumed detection limit (ASTM Gravimetric Method 4281) of 5.0 mg/l. Data obtained from performance tests of the membrane technology are reported lower than this limit (as low as 1 mg/l), but the Agency believes that it is not appropriate for technology based limitations to be set lower than the detection limit specified for the Agency approved oil and grease method. Hence, the Agency will consider 5.0 mg/l to be the long-term average oil and grease concentration. The daily maximum limitation of 13 mg/l and the monthly average of 7 mg/l are calculated using variability factors estimated from the three facility study of granular filtration. The variability factor for the daily maximum limitation is based on the 99th percentile for the distribution of daily oil and grease measurements where four grab samples are composited each day. The variability factor for the monthly average limitation is based on the 95th percentile for the average of four daily composite samples.

c. Reinjection. Reinjection technology for produced water typically consists of injecting it under pressure into subsurface strata or formations. Treatment of the waters prior to injection is usually necessary, and such treatment may include removal of oils and suspended matter by oil separation and filtration technology. The removal of suspended matter for injection is usually performed to prevent pressure build-up and plugging of the receiving formation or strata and/or protect injection pumps from damage. Biocides and corrosion inhibitors are typically added to the waters to minimize corrosion and scaling of injection equipment. Reinjection technology results in no discharge to surface waters, i.e., zero discharge.

Reinjection was considered in the 1985 proposal, both for all structures and for shallow water structures only. EPA, in its preferred option, chose reinjection for all shallow water structures except for gas wells, which were allowed to discharge according to the improved BPT performance option. Gas wells create considerably less discharge volumes, and it was considered appropriate not to require zero discharge for these wells. Zero discharge was considered appropriate for shallow water wells (and not for deep water wells) because EPA found that shallow water structures can, and do, pipe produced water to shore because onshore treatment and reinjection is less costly than installing and operating individual on-platform systems.

As part of today's proposal, and in response to industry concerns about the feasibility of reinjection due to the formation characteristics, EPA evaluated the implementation of this technology for both existing and new platforms. The study showed that reinjection is generally technologically feasible in all offshore areas, i.e., suitable formations and conditions are available for disposal operations. However, specific locations may experience problems in being able to inject due to formation characteristics or proximity to seismically active areas.

EPA is evaluating options which are based on reinjection of produced water from shallow wells only, or from all producing structures regardless of location or water depth.

d. Other Technologies. In 1985, EPA also considered other technologies such as carbon adsorption and biological treatment for treatment of produced waters. Carbon adsorption was rejected from further investigation because the limited use of this technology does not give sufficient performance data to evaluate competitive adsorption phenomena. Biological treatment was rejected because of the severely difficult problems associated with biologically treating briny waters. Chemical precipitation was also considered but rejected because of operational problems and non-quantifiable reductions of priority pollutant metals levels.

The use of hydro-cyclones to treat produced water was also investigated in 1985. This process uses the kinetic energy of pumped produced water to spin it causing materials of different specific gravity to separate, in this case, oil and water. Theoretically, the higher the pressure that the units are operated, the higher the induced gravity and the greater the oil-water separation and contaminant removal. The units are relatively simple to operate and are suited for use on offshore platforms. Little maintenance is required except for unit or liner replacement due to wear. The removed oil can be combined with the platform oil production. Information on this technology at the present time demonstrated only that it was capable of meeting the BPT limits for oil and grease.

4. Deck Drainage, Domestic and Sanitary Wastes

The treatment technologies evaluated for deck drainage are the same as those for the produced water waste stream. No additional technologies beyond BPT and current permit requirements were considered for domestic and sanitary wastes. (However, control of foam is an additional requirement proposed for domestic wastes.)

5. Produced Sand

In addition to current permit requirements zero discharge has been evaluated for produced sand. This is considered feasible because, in most cases due to the small volumes, produced sands can be stored in barrels and barged onshore for disposal, especially in cases where barging is already necessary for other transport requirements.

6. Well Treatment, Completion and Workover Fluids

EPA is considering treatment options for zero discharge of all well treatment, completion, and workover fluids, zero discharge of a 100-barrel buffer on both sides of the fluids slug plus the slug itself or setting the limitation on these fluids equal to the BPT requirement prohibiting the discharge of free oil. For those fluids where a discrete slug does not resurface, the 100-barrel buffer option would not apply. Rather, the fluids would be treated along with the produced water.

XI. Best Practicable Technology

EPA is not proposing to modify existing BPT limits in this rulemaking; however, the Agency is considering requiring the use of a static sheen test method for demonstrating compliance with the BPT as well as BAT, BCT, and NSPS "no free oil" requirement. This is discussed in section VII of today's notice.

XII. Selection of Control and Treatment Options for BCT

A. Methodology

The BCT level of control is based upon the requirement that limitations for conventional pollutants be assessed in light of "cost-reasonableness." 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.

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

1. The removal cost is less than the comparative cost for removal of conventional pollutants at a typical publicly owned treatment works (POTW); the POTW cost is $0.46 per pound (in 1986 dollars).

2. The ratio of the incremental BPT to BCT cost divided by the BPT cost for the industry must be less than 1.29; as such, the cost increase must be less than 129 percent.

These two criteria represent the two-part BCT cost test. Each of the regulatory options was analyzed according to this cost test to determine the appropriate BCT limitations for drilling fluids, drill cuttings, and produced water are appropriate. 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, e.g., oil and grease measurement. The use of BOD and oil and grease would result in double-counting, thus giving erroneous results. The differences between the various BCT options are explained below.

B. Drilling Fluids and Cuttings

1. Options Considered

There are four options considered for drilling fluids and drill cuttings for BCT. One option is based on water depth, one option is based on well distance from shore, and two are applicable to all structures regardless of location or water depth. They are summarized in Table 11 as described below.

TABLE 11.—SUMMARY OF BCT DRILLING FLUIDS AND CUTTINGS OPTIONS

Option	Applicability	Control level
BPT All Structures.	All structures	BPT.[1]
Zero Discharge Shallow; BPT Deep.	Shallow water structures.	Zero discharge.
	Deep water structures.	BPT.[1]
Zero Discharge Within 4 Miles; BPT Beyond.[2]	<4 miles from shore.	Zero discharge.
	>4 miles from shore.	BPT.[1]
Zero Discharge All Structures.	All structures	Zero discharge.

[1] BPT requirement of "no free oil" determined by static sheen test.
[2] Preferred option in today's notice. BPT would apply to all wells in Alaskan waters.

BPT All Structures: This option is equal to BPT as promulgated on April 13, 1979 (44 FR 22069) except the static sheen test would be used to determine free oil. This was the option proposed in 1985.

Zero Discharge Shallow; BPT Deep: This option distinguishes between offshore structures located in shallow water and those located in deep water. For offshore structures located in shallow water, there is a zero discharge requirement which is based on recycle/reuse of the drilling fluid portion of the drilling fluid system and/or transport (mostly by barging) to shore for treatment and for land disposal of the spent mud system and associated cuttings. For offshore structures located in deep water, discharge requirements are the same as for the "BPT All" option described above.

Zero Discharge Within 4 Miles; BPT Beyond: Zero discharge is required for wells drilled at a distance of 4 miles or less from shore. All structures drilled at a distance greater than 4 miles would be regulated by the "BPT All" discharge limitations option.

Zero Discharge All Structures: Zero discharge would apply to all offshore structures regardless of location or the depth of water in which they are located.

TSS and oil and grease are the only conventional parameters for which the BCT analysis was conducted 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, e.g., oil and grease measurement. The use of BOD and oil and grease would result in double-counting, thus giving erroneous results. The parameter of settleable solids was not included as a limitations option for consideration because both drilling fluids and drill cuttings are so high in total solids content, both settleable and suspended. The only option suitable for the control of suspended solids is zero discharge. In addition, EPA is not aware of any control technologies other than zero discharge that are specifically developed and operated for the removal of total suspended solids from drilling wastes. Rather, there are technologies that remove oils from drilling wastes. Therefore, the only BCT options more stringent than BPT that are considered are those involving zero discharge.

2. Alaskan Waters

Comments were submitted to EPA regarding specific situations in Alaskan waters (state and OCS waters off of Alaska) which make compliance with a zero discharge requirement based on barging and land 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 restrict visibility. White-out conditions occur restricting air and water travel. For these reasons, the long distances required to barge to areas which may be suitable for land disposal, and the lack of current land disposal sites, EPA is proposing to exclude Alaskan waters from zero discharge based on barging (under any options).

However, zero discharge of drilling wastes may be attained by reinjection of the fluids and ground cuttings. EPA is aware that this is occurring at one location in Alaska on an experimental basis only. EPA solicits comments on the feasibility of requiring zero discharge based on reinjection, rather than barging of wastes to land for onshore disposal, for Alaska.

3. Options Selection

Cost for BPT for drilling fluids was calculated based on disposal of oil-based drilling fluids which had to be disposed onshore because they failed the sheen test. This is the only cost attributed to BPT. Since oil and grease related parameters (such as oil content) are normally measured in drilling wastes and not the oil and grease content, the pounds of oil content removed is used as a surrogate for oil and grease in the calculations. The following are annual costs and conventional pollutant removals for drilling fluids:

Cost: $13,895,000 (1986 dollars).
TSS Removal: 186,373,000 lb/yr.
Oil Removal: 7,862,000 lb/yr.
Total Conventional Pollutants Removal=194,235,000 lb/yr.

Thus, the BPT cost of conventional pollutant removal for drilling fluids is $0.0715 per pound.

The cost of each regulatory option for drilling fluids was determined by dividing the "Cost of Pollutant Removal" by the amount of TSS and oil removal achieved under the option. For example, the annual cost of removal for zero discharge for all structures is $235,984,000 (in 1986 dollars). Zero discharge achieves an incremental removal above BPT of 1.443 billion pounds of TSS and 10.0 million pounds of oil. The BCT (option) removal cost is $0.162 per pound. This is less than the comparable POTW benchmark removal cost ($0.46/lb in 1986 dollars); thus, the option passes the first test. The second test, the Industry Cost Ratio (ICR), is calculated as follows:

$$ICR = \frac{\text{BCT cost—BPT cost}}{\text{BTP cost—preBPT cost}} =$$

$$\frac{\text{\$/lb BCT—\$/lb BPT}}{\text{\$/lb for BPT—\$/lb preBPT}}$$

$$ICR = \frac{.162—.0715}{.0715—0} = 1.27$$

The ICR is less than 1.29; thus, the option passes the second portion of the test. As such, BCT limitations based on the zero discharge regulatory option for drilling fluids pass both tests. Table 12 presents the results of the BCT cost tests for drilling fluids. All options pass both tests.

TABLE 12.—BCT COST TEST FOR DRILLING FLUIDS

Option	Cost ($/yr)	Removal (lb/yr)	Removal Cost ($/lb)	POTW Test (must be <0.46) (Pass/Fail)	ICR	ICR Test (must be <1.29) (Pass/Fail)
Zero Discharge Shallow; BPT Deep	68,387,200	421,073,000	0.162	Pass	1.27	Pass.
Zero Discharge All	236,984,000	1,453,000,000	0.162	Pass	1.27	Pass.
4 Mile Zero Discharge; BPT Beyond	36,601,600	225,360,000	0.162	Pass	1.27	Pass.

Costs expressed in 1986 dollars.
ICR: Industry Cost Ratio

For the various drill cuttings options, the cost and conventional pollutant removals for BPT were calculated based on the disposal of cuttings from oil based muds which required disposal onshore because they failed the sheen test. The following are the annual costs and pollutant removals:

Cost—$4,852,000.
TSS Removal—51,221,000 lb/yr.
Oil Removal—7,122,000 lb/yr.
Total Conventional Pollutants Removal=58,343,000 lb/yr.

The BPT cost per pound of conventional pollutant removal for drill cuttings is $0.083 per pound.

The BCT cost test procedure was then applied to the drill cutting wastes, and a summary of the results is shown in Table 13. Each of the options evaluated passes both test criteria.

TABLE 13.—BCT COST TEST FOR DRILL CUTTINGS

Option	Cost ($/yr)	Removal (lb/yr)	Removal Cost ($/lb)	POTW Test Must be <0.46) (Pass/Fail)	ICR	ICR Test (Must be <1.29) (Pass/Fail)
Zero Discharge Shallow; BPT Deep	20,924,714	222,909,571	0.094	Pass	0.95	Pass.
Zero Discharge All	72,205,000	769,195,000	0.094	Pass	0.95	Pass.
4 Mile Zero Discharge; BPT Beyond	11,199,143	119,303,714	0.094	Pass	0.95	Pass

Costs expressed in 1986 dollars.
ICR: Industry Cost Ratio

Zero discharge for all structures was determined to be available and technologically feasible technology and it passes the BCT cost test. Upon detailed evaluation, however, certain non-water quality environmental impacts incident to ship transportation and barging surfaced as significant concerns. As a result of these concerns, "Zero Discharge All Structures" is not being proposed as the preferred option for BCT control of drilling fluids and drill cuttings; instead, EPA is proposing as preferred the "4 Mile Zero Discharge; BPT Beyond" option.

Section 304(b)(4)(B) of the Clean Water Act requires EPA to take into account a variety of factors, in addition to the foregoing BCT cost test, in establishing BCT limitations. These additional factors include "non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." EPA conducted an investigation into both the impacts of barging and the availability of land for drilling waste disposal (see section XVIII). These non-water quality environmental impacts and energy requirements and their effect on the selection of EPA's preferred options for control of drilling fluids and drill cuttings covering existing sources and new sources are summarized here; however, they are discussed in greater detail in section XIV and section XVIII.

While EPA's study of non-water quality environmental impacts estimated that sufficient land disposal facility capacity is, or would be, available to support a zero discharge requirement applicable to existing sources and new sources, EPA is concerned about the use of the large amount of land that would be required for this purpose. In addition, EPA is currently conducting a study under the Resource Conservation and Recovery Act (RCRA) of wastes associated with oil and gas activities to determine whether additional, more stringent requirements are necessary for the treatment and disposal of such wastes. The outcome of this effort might have a significant effect on the future available capacity and/or cost of land disposal for drilling fluids and drill cuttings.

The evaluation of barging requirements also estimated the air emissions from fuel consumption that would be necessary for transport of the fluids and cuttings to shore from existing sources and new sources as a result of a zero discharge requirement applicable to all sources. These estimates were unexpectedly high in air emissions and fuel use in comparison with the other options (See section XVIII). Thus, while zero discharge is technologically feasible and passes the BCT cost test, other options were explored which allowed discharges for certain portions of the industry in order to minimize these impacts.

EPA has selected the "4 Mile Zero Discharge; BPT Beyond" option as its preferred option for BCT effluent limitations for drilling fluids and cuttings. This option proposes zero discharge based on barging and land disposal for new wells drilled on existing structures at a distance from the inner boundary of the territorial seas (shore) of 4 miles or less. New wells drilled on existing structures at a distance greater than 4 miles would be allowed to discharge after meeting BPT requirements using the static sheen test. However, for BCT in the Alaska region, BCT would be set equal to BPT for new wells because, as previously discussed, the special climate and safety conditions that exist for parts of the year make barging especially difficult and hazardous, the lack of current disposal sites, and the long distance that barging would have to occur over.

The "4 Mile Zero Discharge; BPT Beyond" option, when compared to the zero discharge option for all drilling fluids and drill cuttings, substantially reduces the amount of material requiring land disposal. Increases in both air emissions and fuel use are also substantially less. See section XIV. EPA believes the non-water quality environmental impacts associated with the "4 Mile Zero Discharge; BPT Beyond" option, in conjunction with those associated with the BAT/NSPS preferred option for control of drilling fluids and drill cuttings, are reasonable.

See sections XV, XVI, XVII, and XVIII of today's notice for detailed discussions of non-water quality environmental impacts, costs, and economic impacts.

C. Produced Water

1. Options Considered

Seven options were considered by EPA for the regulation of produced water for BCT. Three options are based on water depth, one option on platform distance from the shore, and three options apply to all platforms regardless of location or water depth. Table 14 summarizes the options.

TABLE 14.—SUMMARY OF BCT PRODUCED WATER OPTIONS

Option	Applicability	Control level
BPT All Structures [1]	All structures	BPT.
Filter and Discharge Within Four Miles; BPT Beyond	≤ 4 Miles from shore	Filter and discharge.[2]
	≤ 4 miles from shore	BPT.
Filter and Discharge Shallow; BPT Deep	Shallow water structures	Filter and discharge.[2]
	Deep water structures	BPT.
Filter and Discharge All Structures	All structures	Filter and discharge.[2]
Zero Discharge Shallow; BPT Deep	Shallow water structures	Zero discharge.
	Deep water structures	BPT.
Zero Discharge Shallow; Filter Deep	Shallow water structures	Zero discharge.
	Deep water structures	Filter and discharge.[2]
Zero Discharge All Structures	All structures	Zero discharge.

[1] Perferred option in today's notice.
[2] Discharge limits for "Filter and Discharge" options are being considered based on membrane and granular filtration. Within these options, EPA prefers filtration limits for oil and grease of 13 mg/l daily maximum and 7 mg/l monthly average, based on membrane filtration. The granular filtration discharge limits for oil and grease that are being considered are 29 mg/l daily maximum and 16 mg/l monthly average.

The manner of control involves various combinations of treatment and discharge and/or zero discharge. The treatment and discharge technologies considered in the options described below involve either BPT, filtration, or reinjection. The limits associated with these technologies are for oil and grease.

Filter and Discharge Shallow; BPT Deep: This option distringuishes between those offshore structures that are located in shallow water and those located in deep water. The offshore structures located in shallow water would have requirements based on the use of filtration (granular media or membrane separation) technology as an add-on to the existing BPT technology (dissolved gas flotation). The 1985 proposal contained a produced water filtration option; however, new data have been collected for both types of filtration—granular and membrane separation—since then, and the proposed limits would be based on the new data. Two sets of limits are considered in this option; however, EPA is identifying the set based on membrane filtration as preferred. For offshore structures that are located in deep water BCT would be set equal to BPT. Better operation of the BPT technology was not selected as preferred because of the problems with the original performance analysis as discussed previously.

Zero Discharge Shallow; BPT Deep: This option also makes a distinction between those structures located in shallow water and those in deep water. Under this option, the offshore structures located in shallow water would be subject to a zero discharge requirement based on reinjection of the produced water. The reinjection system would include oil flotation and gas separation technology (BPT level control), filtration, and an injection well system. For offshore structures located in deep water, BCT would be set equal to BPT.

Filter and Discharge All Structures: All structures, regardless of the water depth or distance from shore at which they are located, would be required to meet limits based on filtration of the produced water prior to discharge. Two sets of limits are considered; however, the limits based on membrane filtration are preferred.

Zero Discharge Shallow; Filter Deep: This option would require offshore structures located in shallow water to meet a zero discharge requirement for the produced water waste stream, while those structures located in deep water would be required to meet discharge limits based on membrane filtration.

Zero Discharge All Structures: This option would require all structures to meet a zero discharge requirement based on reinjection of the produced water.

Filter and Discharge Within 4 Miles; BPT Beyond: Structures located at a distance of 4 miles or less from shore would be required to meet discharge limits based on membrane filtration. Structures located at distances greater than 4 miles from shore would be required to meet the existing BPT limitations only. Other distances, specifically 3, 6, and 8 miles from shore were being considered and are being evaluated for suitability with respect to minimizing non-water-quality impacts.

BPT All Structures: EPA has included as an option setting BCT equal to BPT. By doing so, EPA is not ruling out the possibility that, based on the fluctuating economic stability of the oil market, nature of control technology, costs and pollutant removals, compliance with stricter standards may be unachievable.

2. Options Selection

All options considered for BCT regulation were evaluated according to the BCT cost tests. The pollutant parameters used in this analysis were TSS and oil and grease. All options (except the "BPT All Structures" option) fail the BCT cost test. The range of results for the first (POTW comparison) test is $3.47 to $3.71 per pound of conventional pollutant removed. Thus, EPA is proposing BCT equal to BPT for produced waters. This proposal is the same as that proposed in 1985.

D. Deck Drainage

BPT limitations for deck drainage are for no 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.

EPA's preliminary cost estimates for BCT for deck drainage concluded that the cost to provide treatment capacity for deck drainage (which included dissolved air floatation/filtration) would be considerably more expensive than the cost for BPT treatment. BPT treatment consists of a skim pile and the annual cost to operate a skim pile is on the order of a few pennies per thousand gallons. The cost to operate a filtration unit is $3.36 per thousand gallons and this does not include the operating cost of the dissolved air flotation portion of the treatment unit. As the second cost test for BCT limits the incremental cost to 129 percent of the BPT cost, this option would doubtlessly fail this test.

If the filtration/reinjection option were employed, the costs and conventional pollutant removals would only increase compared to the filtration/discharge option. The conclusions reached above for filtration/discharge option regarding the second cost test would also hold for the reinjection option. As the second test limits the incremental cost to 129 percent of the BPT cost, the option fails this test also.

Thus, EPA is proposing BCT equal to BPT for deck drainage. This is the same as that proposed in 1985.

E. Produced Sand

BPT limitations for produced sand have not previously been promulgated, however, the current permit requirement for produced sand is no discharge of free oil. EPA has not performed a BCT cost analysis on this option, because it is assumed no incremental costs will be incurred since the limitation is currently in effect. Therefore, BCT for produced sand is being proposed as equal to no discharge of free oil.

F. Well Treatment, Completion and Workover Fluids

EPA is not changing the 1985 proposal which set BCT equal to BPT for treatment fluids. No additional cost tests have been performed, however, due to a lack of sufficient data on TSS concentration, both in treated and untreated wastes.

G. Sanitary and Domestic Wastes

Sanitary wastes are human body wastes from toilets and urinals. BPT requirements for discharge are for a minimum free chlorine content residual exceeding 1 mg/l and maintained as close to this concentration as possible.

Domestic wastes result from laundries, galleys and sinks. Current permits require that the discharge of domestic wastes does not result in floating solids. Treatment using macerators is usually sufficient to ensure that the discharge complies with permit requirements.

Given the high cost of offshore operations, it would probably be less costly to transport these wastes to shore than to install a treatment unit. No cost data are available on transport costs for shipment to shore. As muds/cuttings can be transported to shore and disposed of for $36 to $51 a barrel, onshore disposal of sanitary wastes should be less costly by an amount equal to the fee charged by the onshore disposal facility. This cost equals $7 to $10 per barrel. Using the low cost of $26 per barrel and average BOD and TSS levels reported earlier, the cost is $67 per pound of conventional pollutants in the domestic/sanitary waste. Obviously, this greatly exceeds the POTW cost of $0.46 per pound and requiring transfer to shore would not be justified.

Possibly, some on-platform treatment process could achieve a lower cost per pound of conventional pollutant removal than onshore disposal, but it is highly unlikely that it could compete with a POTW (which is designed to achieve the same result on a massive scale) in terms of operational cost. Thus, EPA is not changing the 1985 BCT proposal for sanitary and domestic waste.

XIII. Selection of Options for BAT

A. Drilling Fluids and Drill Cuttings

1. Options Considered

Seven options are being considered for BAT control of drilling fluids and drill cuttings. Below is a discussion of all of the options with particular emphasis on regulation of toxic pollutants. Table 15 summarizes these options.

TABLE 15.—SUMMARY OF BAT/NSPS DRILLING FLUIDS AND CUTTINGS OPTIONS

Option	Applicability	Control level
5/3 all structures	All structures	• Toxicity ≥ 30,000 ppm (SPP). • No diesel oil discharge. • No free oil discharge.[1] • 3 mg/kg mercury, 5 mg/kg cadmium, both in stock barite.
1/1 all structures	All structures	• Toxicity ≥ 30,000 ppm (SPP). • No diesel oil discharge. • No free oil discharge.[1] • 1 mg/kg mercury, 1 mg/kg cadmium, in the whole drilling fluid.
Zero discharge shallow; 5/3 deep	Shallow water structures	Zero discharge.
	Deep water structures	Discharge limits for "5/3 All Structures".
Zero discharge shallow; 1/1 deep	Shallow water structures	Zero discharge.
	Deep water structures	Discharge limits for "1/1 All Structures".
Zero discharge all structures	All structures	Zero discharge.
Zero discharge within 4 miles; 5/3 beyond	≤ 4 miles from shore	Zero discharge.
	> 4 miles	Discharge limits for "5/3 All Structures".
Zero discharge within 4 miles; 1/1 beyond[2]	≤ 4 miles from shore	Zero discharge.
	> 4 miles	Discharge limits for "1/1 All Structures".

[1] Determined by static sheen test.
[2] Preferred option in today's notice.
SPP: Suspended Particulate Phase.

5/3 All Structures: This option includes four requirements: (1) Toxicity limitation set at 30,000 ppm in the suspended particulate phase; (2) a prohibition on the discharge 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 set in the stock barite at 5 mg/kg and 3 mg/kg, respectively. These requirements are to be met by all offshore structures regardless of the depth of the water in which they are located.

The discharge prohibitions on diesel oil and free oil will serve as "indicators" of toxic pollutants. 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 this option. Diesel oil would be regulated at the BAT level because it contains such toxic organic pollutants as benzene, toluene, ethylbenzene, napthalene, and phenanthrene. The method of compliance with this prohibition is to use mineral oil instead of diesel oil for lubricity and spotting purposes or barge 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. Low toxicity mineral oils are also available as substitutes for diesel oil and continue to be developed for use in drilling fluids.

Free oil is proposed to be used as an "indicator" pollutant for control of priority pollutants also, including benzene, toluene, ethylbenzene, and naphthalene.

The toxicity limitation is the same as that proposed in 1985. The purpose of the toxicity limitation for any drilling fluids which are to be discharged is to encourage the use of generic or water-based drilling fluids and the use of low-toxicity drilling fluid additives. The basis for the toxicity (LC50) limitation, as discussed in the 1985 proposal, is the toxicity of the most toxic of the generic fluids.

The Agency has considered the costs of product substitution and finds them to be acceptable for this industry, resulting in no barrier to future entry. (51 FR 29600-09 and 53 FR 37849-50, Draft Beaufort Sea and Beaufort/Chukchi Seas General Permits.) Where the toxicity of the spent drilling fluids and cuttings exceeds the LC50 toxicity limitation, the method of compliance with this option would be to transport the spent fluid system to shore for either reconditioning for reuse or land disposal.

The toxicity limitation would apply to any periodic blow-down of drilling fluid as well as to bulk discharges of drilling fluids and cuttings systems. The term "drilling fluid systems" refers to the major types of materials (muds) used during the drilling of a single well. As an example, the drilling of a particular well may use 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 such systems are changed during the drilling of a well or at the completion of a well.

For the purpose of self monitoring and reporting requirements in NPDES permits, it is intended that only samples of the spent drilling fluid system discharges be analyzed in accordance with the proposed bioassay method. These bulk discharges are the highest volume mud discharges and will contain all the specialty additives included in each mud system. Thus, spent drilling fluid system discharges are the most appropriate discharges for which compliance with the toxicity limitation should be demonstrated. In the above example, four such determinations would be necessary.

For determining the toxicity of the bulk discharge of mud used at maximum well depth, samples may be obtained at any time after 80 percent of actual well footage (not total vertical depth) has been drilled and up to and including the time of discharge. 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.

Cadmium and mercury would be regulated at a level of 5 and 3 mg/kg, 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 barite used in the drilling fluid compositions. These two toxic metals would be regulated to control the metals content of the barite component of any drilling fluid discharges. Compliance with this requirement would involve use of barite from sources that either do not contain these metals or contain the metals at levels below the limitation.

1/1 All Structures: This option also includes four requirements: (1) The same toxicity limitation as above; (2) the same discharge prohibition on diesel oil as above; (3) the same prohibition on the discharge of free oil as above; and (4) limitations for cadmium and mercury in the drilling fluids and cuttings at 1 mg/kg each at the point of discharge. The cadmium and mercury limits are based upon the use of "clean" stock barite which has been costed for use by the industry. Previous comments have stated that the availability of barite stocks containing low levels of trace metals could be limited at any given time due to market conditions. However, EPA investigated the availability of "clean barite" needed to meet the 1/1 mg/kg limitations for cadmium and mercury and estimates that sufficient sources of such barite do exist and can be directed to offshore drilling use in those cases where an operator would be able to discharge drilling fluids based on meeting the other requirements of this option. The requirements in this option are to be met by all existing offshore structures drilling new wells regardless of the depth of the water in which they are located or distance from shore.

Zero Discharge Shallow; 5/3 Deep: This option distinguishes between offshore structures located in shallow water and those located in deep water. For offshore structures located in shallow water, there is a zero discharge requirement which is the same as that portion of the "Zero Discharge Shallow; BPT Deep" option for BCT described in section XII, and is based on recycle/reuse of the drilling fluid portion of the drilling fluid system and/or transport (mostly by barging) of drill cuttings (with residual drilling fluid) to shore for treatment and/or land disposal. For offshore structures located in deep water, the requirements are the same as the first option.

Zero Discharge Shallow; 1/1 Deep: This option also makes a distinction between offshore structures located in shallow water and those in deep water. It is the same as the "Zero Discharge Shallow; 5/3 Deep" option except that the cadmium and mercury requirements are 1 mg/kg each of these limitations apply to the drilling fluid and drill cuttings at the point of discharge.

4 Mile Zero Discharge; 5/3 Beyond: Zero discharge is required for wells drilled at a distance of 4 miles or less from shore, the same as discussed for the BCT option identifying 4 miles as a delineation for zero discharge based on minimizing non-water quality environmental impacts. All new wells (on existing structures) drilled at a distance greater than 4 miles would be regulated by the same limitations included in the "5/3 All Structures" option.

4 Mile Zero Discharge; 1/1 Beyond: Same as "4 Mile Zero Discharge" discussed above for wells drilled 4 miles or less from shore and for wells drilled at a distance greater than 4 miles the limitations are the same as the "1/1 All" option. This option provides for more additional control on the toxic pollutants cadmium and mercury in the drilling fluids and drill cuttings at the point of discharge.

Zero Discharge All Structures: Zero discharge would apply to all offshore structures regardless of the depth of water in which they are located. This option is similar to the "Zero Discharge All" option considered for BCT limitations. The only difference is that the BCT option is considered for control of conventional pollutants, while the BAT option focuses on the control of toxic and nonconventional pollutants.

2. Options Selection

EPA has selected the "4 Mile Zero Discharge; 1/1 Beyond" option as its preferred option for effluent limitations for drilling fluids and drill cuttings based on the same consideration of non-water quality environmental impacts that are summarized in section XII describing the BCT options selection. These impacts are discussed further in section XIV and section XVIII of today's notice. This option proposes zero discharge based on barging and land disposal for new wells drilled from existing structures at a distance from shore of 4 miles or less. New wells drilled from existing structures at a distance of greater than 4 miles would be allowed to discharge after meeting requirements for toxicity, cadmium and mercury at 1/1/ mg/kg respectively, no static sheen, and no discharge of diesel oil. However, for the Alaska region, new and existing wells would be covered by the "1/1 All Structures" option, because the special climate and safety conditions that exist for parts of the year make barging especially difficult and hazardous, the lack of disposal sites and the long barging distances necessary to get to suitable land disposal sites.

EPA is proposing, for the wells drilled at a distance greater than 4 miles, the 1 mg/kg cadmium and 1 mg/kg mercury limitations at the point of discharge instead of the 5 mg/kg cadmium and 3 mg/kg mercury limitations in the stock barite because (a) EPA believes it more appropriate to develop effluent standards based on point source discharge limitations than on the regulation of only one raw material component of the discharge (barite in this case); and (b) it represents control at the BAT level based on the evaluation of cadmium and mercury discharge monitoring report (DMR) data reporting concentrations of these metals in drilling fluids and drill cuttings that demonstrate the ability of the industry to meet these limits. These data represent compliance information reported from facilities located offshore in the Pacific Ocean and Gulf of Mexico and covered by several levels of concentration limitations depending upon the individual (facility or general) permit requirements. Evaluation of the DMR data showed that even though industry was operating under less stringent metals limits than the 1/1 mg/kg cadmium/mercury limits being proposed today, discharges would have been in compliance with the 1/1 mg/kg requirement for the four cases where the NPDES permits established a 2/1 mg/kg cadmium/mercury requirement, and 67 percent of the time for operators under a 3/1 mg/kg cadmium/mercury requirement, and even 16 percent of the time in the Gulf of Mexico, where there are currently no cadmium/mercury requirements.

However, EPA is still considering, for this option and other options presented in today's proposal, a 3 mg/kg cadmium and 1 mg/kg mercury limitation in the barite based on the continuing evaluation of the availability of barite required to meet the limitations. The influence of underground formation characteristics on the level of cadmium and mercury in drill cutting and recycled drilling fluids will also be considered.

In addition to noncompliance with the cadmium and mercury limitations attributable to the use of barite with high metals content, commenters responding to the 1985 and 1988 proposal notices have stated that the presence of cadmium in the formation itself could cause noncompliance with limitations applied at the drilling waste discharge point. In response to this comment, EPA has analyzed data from the American Petroleum Institute's Fifteen Rig Study. In this study, operators of 14 rigs volunteered to collect matched sets of measurements. Each rig collected a sample of drill cuttings, a sample of used drilling fluids, and a sample of barite that was present at the time the first two samples were taken. Splits or duplicates of these samples were analyzed by labs associated with the Agency. Results of statistical analysis indicate that some cadmium present in the drilling fluids came from a source other than the barite. In particular, physical analyses by the industry lab indicate that 11 out of 14 rigs had higher cadmium concentrations in their drilling fluid than in their barite. Physical analyses by the Agency lab indicate that 13 out of the 13 rigs for which the Agency lab reported results, had higher cadmium concentrations in their drilling fluid than in their barite. These results suggest that cadmium, from a source other than barite, is contaminating the drilling fluid.

This conclusion is based on the assumption that metals are uniformly distributed throughout the barite present at a single rig and throughout the drilling fluids used on that rig. The Agency requests information as to the appropriateness of this assumption and its requests information on what additional sources of cadmium may affect drilling fluids.

The annualized cost for this option and its cost-effectiveness are $29.5 million and $22 per pound-equivalent, respectively. Two of the other distance options evaluated (6 and 8 miles), as well as the shallow/deep option, are not as attractive because they do not appreciably reduce the non-water quality impacts compared to the 4 mile option. The 3 mile option was not fully evaluated due to the lack of data on existing structure locations.

EPA solicits comments on the "4 Mile Zero Discharge; 1/1 Beyond" option and the other options as well. EPA especially invites comment on the appropriateness of the "5/3 All Structures" and "1/1 All Structures" discharge options and also on the "Zero Discharge All Structures" option.

See sections XV, XVI, XVII, and XVIII for detailed discussions of non-water quality environmental impacts, costs, economic, and environmental impacts.

B. Produced Water

1. Options Considered

The options considered for produced water under BAT are the same as those discussed previously 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. It is being limited under BAT as an indicator pollutant controlling the discharge of toxic pollutants (see section IX).

2. Options Selection

EPA has selected for BAT proposal and "Filter within 4 miles; BPT Beyond" option as its preferred option. This option requires all existing production structures located at a distance of 4 miles or less from shore to meet discharge limitations based on membrane filtration, and all existing production structures located at a distance greater than 4 miles from shore to meet the current BPT limitations. EPA has determined this option to be economically and technically feasible.

Membrane filtration is being used as the technology basis for the proposed limits on produced water BAT since it is a demonstrated technology, the EPA has acquired sufficient data to develop effluent limits of 13 mg/1 for daily maximum with a composite sample and 7 mg/1 for the maximum monthly average. Although not yet in widespread use in the oil and gas industry, membrane filtration is a commercially demonstrated technology in several other industries and is considered to be applicable to oil and gas effluents, as shown by extensive pilot scale tests and movement toward commercial application of this technology to treat produced water. To obtain additional full-scale data other than oil and grease results, studies are planned to obtain performance information from these treatment systems with respect to specific toxic and nonconventional pollutants. Such data will be used to further assess the potential for developing limitations based on membrane technology and its availability will be noticed in the Federal Register if appropriate. EPA solicits any information available on membrane filtration technology and its performance regarding the treatability of oil and gas produced waters.

Another set of limitations (29 mg/1 for daily maximum with a composite sample and 16 mg/1 for maximum monthly average) was considered based on performance of the granular filtration technology. Granular filtration is being used in the oil and gas industry. However, EPA chose to propose produced water limitations as its preferred option based on membrane filtration due to its better performance and projected lower cost relative to granular filtration systems. EPA solicits information concerning the relative technical efficiency and cost of these alternative treatment systems. Should membrane filtration ultimately prove to be insufficiently demonstrated to serve as the basis for produced water treatment, EPA will base the limitations on alternative technologies giving strong consideration to BPT as the basis for BAT since the costs of alternative technologies are high.

EPA did not select the most stringent option, zero discharge based on reinjection, for three reasons. First, there are questions concerning the applicability of reinjection to all structures. Although reinjection may be technically feasible in general, depending on geological conditions, specific structures would not be able to reinject. Second, the air emissions and fuel use associated with the large pumps necessary to reinject fluids are unacceptably high. Finally, reinjection for all production structures would result in a 4.9 percent (13 million BOE/year) production loss in barrels of oil equivalent (BOE). 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 and new source performance standards under the Clean Water Act.

EPA did not select the "Filtration All" option as preferred because of the potential adverse effects on oil and gas production (approximately 3 million BOE per year based on membrane filtration).

The other options considered would require filtration for near-shore wells but BPT controls for wells farther offshore; these options use water depth and distance from shore as alternative means of reducing the loss of oil and gas production. EPA selected the 4 mile distance in order to minimize the loss of oil and gas production resulting from controls on produced water and because it is consistent with the 4 mile distance used in the preferred options for control of drilling fluids and drill cuttings. This option also has the lowest associated fuel requirements and air emissions of any of the options considered.

Reinjection does eliminate potential discharge of radionuclides, particularly radium-226 and -228. These radionuclides have been measured at elevated levels (as high as several thousand picoCuries per liter) in produced water discharges on coastal and near-shore areas in the Gulf of Mexico. EPA is concerned about the possible effects of radium in produced water discharges on human health and the environment. Options involving zero discharge based on reinjection will receive further consideration as more data on radionuclides are obtained.

The "Filtration All" option is also being given consideration as the basis for BAT for promulgation, since the potential effect of this option on offshore production is a very small percentage of the total of present value of offshore production at existing structures (1.1 percent assuming membrane filtration is installed).

EPA solicits comment on the viability and appropriateness of the other options for produced water, especially with respect to the "Filtration All Structures", "BPT All Structures" and "Zero Discharge" options.

See sections XV, XVI, XVII, and XVIII of today's notice for further discussion of costs, environmental assessment, and economic and non-water quality environmental impacts for these options.

C. Deck Drainage

Deck drainage consists of platform and equipment runoff due to storm events and wastewater as a result of platform and equipment washdown/cleaning practices. Options being considered as a basis for BAT for this waste stream are either to establish the requirement equal to the current BPT limits of no discharge of free oil (with compliance measured by the static sheen test) or to require the same standards as those selected for the produced water waste stream. In many instances the deck drainage waste stream has similar pollutant characteristics as produced water and is commingled, and therefore treated, with the produced water waste stream. Due to the similarity and commingling of waste streams, the same BAT options, in addition to current BPT as an option, presented for the produced water waste stream are considered for the deck drainage waste stream.

The volumes of deck drainage are minimal compared to the volumes of produced water and the deck drainage waste stream is not a continuous flow waste stream. Thus, the capacity of the produced water treatment system would not have to be increased to accommodate the deck drainage volumes so it is expected that no additional costs would be incurred. As described later in section XV, Revised Technologies Costs and Assumptions, and in section XIX, Solicitation of Comments, two sets of costs for produced water treatment were developed and evaluated for economic achievability. Even the higher costs, which include geographic factors based on Alaska construction and operation considerations and platform structural additions at every location for the installation of the filtration units, did not significantly change the economic achievability. In the case of the models used to cost produced water treatment systems, EPA believes the normal safety margins included in costing these systems will accommodate the minimal costs that may be associated with intermittent treatment for deck drainage. Thus, the economic impact analysis for produced water is considered to include the necessary deck drainage volumes for treatment to comply with the options considered. No separate evaluations have been conducted for the economic analyses of the options for deck drainage.

EPA has selected as its preferred option for effluent limitations for deck drainage the produced water discharge option based on filtration for facilities at 4 miles and less from shore and the BPT produced water oil and grease limitations for facilities greater than 4 miles from shore. This is because deck drainage is similar in pollutant characteristics and can be commingled and treated with produced water.

There are, however, certain situations where effluent limitations based on filtration may not be appropriate for deck drainage. For example, deck drainage occurs on drilling platforms where a production well may not exist; therefore, the produced water treatment may not be in place either. Thus, EPA is proposing that the produced water "Filter 4 Mile Within; BPT Deep" option be applicable to deck drainage during the production phase of the oil and gas extraction operation only, and at earlier stages, the BPT limits on free oil will apply.

D. Produced Sand

Produced sand consists of sand and other particulate material from the producing formation and production piping, which comes to the surface along with the crude oil and/or gas and produced water and is separated by the produced water desander (settling/ screening device) and treatment system. This waste stream could also include sludges generated by any chemical polymer use in the filtration portion (or other portions) of the produced water treatment system. There are two options being considered for this waste stream: (1) Establish the requirement equal to the current permit limits of no discharge of free oil or (2) require zero discharge by barging and treatment/disposal onshore. The technology basis for the options limiting free oil is a water or solvent wash of produced sands prior to discharge. The method of determining compliance with the free oil prohibition is by the static sheen test discussed earlier.

The prohibition on the discharge of free oil or the zero discharge requirement for produced sand would act to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. Becasue this waste stream is of low volume and because most facilities currently practice either washing or land disposal to meet the free oil limitation, the Agency did not attribute any compliance costs to this proposed option except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

The zero discharge option would also impose nominal impacts because the volume of sand in most locations would be minimal and would be barged to shore infrequently and as part of the barging of other materials for disposal.

The option selected for proposal is zero discharge for all facilities based on the minimal volume of waste zero discharge represents the best technology which is both economically and technically feasible. However, zero discharge for structures 4 miles or less from shore and the free oil limitation options are still being considered as a basis for the final rule if information is made available to show that the volumes of produced sand are significantly higher than EPA raw estimates.

E. Well Treatment, Completion and Workover Fluids

Well treatment, completion and workover fluids either stay in the hole, resurface as a concentrated volume (slug), or are dispersed with the produced water. There are three options being considered for these wastes: (1) Establish the requirements equal to the current BPT limit of no discharge of free oil; (2) require zero discharge of any concentrated slug of fluids along with a 100-barrel buffer on either side of the fluids slug; or (3) meet the same requirements as produced water (based on filtration, reinjection, or current produced water BPT).

The prohibition on the discharge of free oil and the zero discharge (reinjection along with produced water) requirement are both intended to reduce or eliminate the discharge of toxic pollutants. The method of compliance with the free oil prohibition would be the static sheen test.

The zero discharge of the fluids slug would require capturing 100-barrel buffers on both sides of the slug, plus the slug, and barging it to shore for land disposal. For those fluids that cannot be segregated from the produced water waste stream, the produced water limitations would apply.

For cases where the fluids resurface as a discrete slug, EPA has selected zero discharge of the slug plus a 100-barrel buffer on either side of it as the preferred option. Where the fluids are diffused with the produced waters, the preferred option for produced waters will apply (e.g., based on filtration at 4 miles and less, and produced water BPT limitations at greater than 4 miles).

F. Domestic and Sanitary Wastes

The Agency is not proposing to establish BAT effluent limitations for these waste streams, because there have been no toxic or nonconventional pollutants of concern identified in sanitary or domestic wastes.

XIV. Selection of Control and Treatment Options for NSPS

The basis for new source performance standards under section 306 of the Act is the "best available demonstrated technology." New facilities have the opportunity to design and implement the best and most efficient processes and waste 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.

The control and treatment options investigated as a basis for NSPS to reduce the discharge of pollutants in waste streams generated by the offshore segment of this industry consist of those options evaluated for use in the BCT and BAT levels of control. No additional demonstrated technologies were identified that would be applicable to new sources only. However, some of the options considered but not identified as preferred for BAT, or for that matter NSPS, are still being seriously considered for the basis of NSPS in the final rule, provided that additional information can be obtained. Since all of the options considered are the same as previously described for BCT and BAT, with the exception of the proposed NSPS prohibition on discharge of foam for domestic wastes, no detailed discussion is repeated here.

For drilling fluids and drill cuttings, the preferred option for proposal is the same as BAT, "Zero Discharge Within 4 Miles; 1/1 Beyond", and is based upon the same factors. These factors are the minimization of potential non-water quality environmental impacts due to the large volume of solids requiring land disposal and the air emissions and fuel use associated with transportation of the solids to land. It is estimated that only about four percent of the new well drillings will be on existing structures (platforms); thus, the assignment of costs and impacts for evaluating the limitations are shown under the NSPS selection for drilling wastes. The non-water quality environmental impacts are described in section XVIII, along with the evaluation conducted to minimize the estimated impacts.

Section 306(b)(1)(B) of the Clean Water Act requires EPA, in establishing new source performance standards, to take into account any non-water quality environmental impacts and energy requirements incident to the rules. Non-water quality environmental impacts and energy requirements have played an important role in EPA's selection of its preferred NSPS option for control of drilling fluids and drill cuttings.

The most stringent option considered by the Agency, zero discharge of drilling fluids and drill cuttings for all structures (based on transport of spent drilling wastes to shore for recovery, reconditioning for reuse or land disposal) was determined to be technologically and economically achievable. However, a zero discharge requirement applicable to all structures would cause an enormous amount of solids (estimated at 8.2 million barrels per year) to be barged to shore for land disposal. In developing this proposal, EPA studied the non-water quality environmental impacts caused by the barging of this quantity of drilling waste to land and the availability of appropriate landfill sites for its ultimate disposal. (See section XVIII of today's notice).

EPA's evaluation of the non-water quality environmental impacts of barging focused on the air emissions that would result from the transport of 8.2 million barrels of drilling fluids and drill cuttings to shore. Air emissions from sources on the OCS are a matter of longstanding concern to the Agency, Congress and states adjoining OCS areas where oil and gas operations take place. Section 801 of the Clean Air Act Amendments of 1990 (codified as new section 328 of the Clean Air Act) reflects this concern. This new provision requires EPA to "establish requirements to control air pollution" from OCS sources located offshore of the states along the Pacific, Arctic and Atlantic coasts and along the Gulf coast off the State of Florida. The air pollution control requirements that are to be established pursuant to new section 328 must "attain and maintain Federal and State ambient air quality standards" and comply with the provisions of title I, part C of the Clean Air Act, which relate to the prevention of significant deterioration. For sources located within 25 miles of the seaward boundary of these states, the requirements "shall be the same as would be applicable if the source were located in the corresponding onshore area."

New section 328 identifies "platform and drill ship exploration, construction, development, production processing and transportation" and "emissions from any vessel servicing or associated with an OCS source" as specific air pollutant sources of concern.

In addition, new section 328 of the Clean Air Act requires the Secretary of the Interior, in consultation with the Administrator of EPA, to "assure coordination of air pollution control regulation for Outer Continental Shelf emissions and emissions in adjacent onshore areas" for portions of the Gulf coast OCS off the states of Texas, Louisiana, Mississippi and Alabama.

The Agency has estimated that the air emissions associated with barging to attain zero discharge of drilling fluids and drill cuttings would be 6,352 short tons of particulates, nitrous oxides, carbon dioxide, hydrocarbons and sulphur oxides per year. This estimate was unexpectedly high in comparison to other options, which ranged from 532 short tons for the "5/3 All" and "1/1 All" options to 2,116 short tons for the "Zero Discharge Shallow; 5/3 Deep" and the "Zero Discharge Shallow; 1/1 Deep" options. (See Table 22.)

In examining energy requirments, EPA estimated the amount of diesel fuel that would be required to operate the barging systems associated with the options under consideration. The amount of fuel that would have to be expended to attain zero discharge was estimated at 818,029 barrels per year. This figure also is significantly higher than the fuel use estimates associated with the other options, which ranged from 79,517 barrels per year for the "5/3 All" and "1/1 All" options to 293,535 barrels per year for the "Zero Discharge Shallow; 5/ 3 Deep" and the "Zero Discharge Shallow: 1/1 Deep" options. (See Table 22.)

Finally, EPA studied the availability of land for drilling waste disposal in connection with its evaluation of the control options for drilling fluids and drill cuttings. The study estimated the available capacity of all existing landfills in the Gulf of Mexico region and California. The Agency concluded that sufficient capacity is, or would be, available to support a zero discharge requirement. However, the 8.2 million barrels of drilling wastes that would be generated annually as a result of the zero discharge requirement represents approximately 57 percent of the capacity of the existing landfills in the Gulf area and California (there are currently no landfills in Alaska that accept these wastes), and approximately 18 percent of the projected available landfill capacity in these areas. EPA is concerned about the use of this segment of existing landfill capacity for the disposal of drilling wastes. These concerns are compounded by the fact that EPA is currently conducting a study under RCRA of wastes associated with oil and gas activities to determine whether additional, more stringent requirements are necessary for the treatment and disposal of such wastes. The outcome of this effort might have a significant effect on the future available capacity and/or cost of land disposal for drilling wastes and drill cuttings.

Thus, while zero discharge is technologically and economically achievable, EPA determined that the non-water quality environmental impacts and energy requirements associated with this option are significant enough to rule out the selection of this option as preferred.

The volume of drilling wastes that would have to be transported to shore for disposal as a result of the "4 Mile Zero Discharge; 1/1 Beyond" option is 1.6 million barrels annually, a reduction of approximately 80 percent as compared to zero discharge. This reduces the impacts on landfill capacity accordingly. The fuel requirements associated with this option are 173,360 barrels per year, also reduction of 80 percent. Annual air emissions are reduced by about 82 percent, from 6,352 short tons to 1,166 short tons compared to the zero discharge option. EPA believes these non-water quality environmental impacts associated with the "4 Mile Zero Discharge; 1/1 Beyond" option are reasonable. The "4 Mile Zero Discharge; 1/1 Beyond" option also has the advantage of eliminating discharges of drilling fluids and drill cuttings from the sensitive marine areas within four miles of shore while subjecting discharges seaward of that area to stringent controls. The other distance options (6 and 8 miles), as well as the shallow/deep options, do not appreciably reduce non-water quality environmental impacts compared to the 4 mile option, and insufficient information is available to evaluate 3 miles.

For NSPS produced water, in addition to the proposed option of "Filtration Within 4 Miles; BPT Beyond" which is the same as the BAT proposal, and the "Filtration All Structures" option which is also being strongly considered, zero discharge at 4 miles or less in conjunction with BPT or filtration beyond 4 miles are being considered for NSPS. The proposed NSPS option is the same as BAT based on the estimated loss of production associated with the other options. For example, the loss for the "Filtration All" options, although small in percent of total production (0.2 percent), is still quite large in barrels of oil equivalent (1.1 million BOE per year). These considerations are discussed in more detail in section XIII.B describing the BAT options selection for produced water. For the reinjection options, the generation of additional air emissions due to the increased use of high pressure pumping is significant, although selecting a 4 miles and less from shore option requiring zero discharge based on reinjection will minimize the air emissions impact to some extent. This technology option would reduce overall discharge of pollutants and eliminate within 4 miles of shore the discharge of radionuclides, specifically radium-226 and radium-228. Preliminary information shows that elevated levels of these radionuclides are present in produced water, with some of the highest measurements coming from oil and gas production areas along the Gulf of Mexico coast. EPA may consider reinjection technology options further based on obtaining additional data, further characterizing the radionuclides in produced water discharges, and identifying geographic areas where there are pollutants of concern in produced water. See sections XV, XVI, XVII, XVIII of today's notice of further discussion of costs, environmental assessment, and economic and non-water quality environmental impacts for these options.

For well treatment, completion and workover fluids that resurface as a discrete slug, NSPS is proposed as zero discharge of the slug plus a 100-barrel buffer on either side of the slug. In the case where these fluids are diffused with the produced water, the limits of the preferred option for produced water (Filtration Within 4 Miles; BPT Beyond) will apply. NSPS for deck drainage during production is proposed as equal to the preferred option for produced water. During drilling operations, NSPS for deck drainage is proposed to be equal to BPT limits prohibiting discharge of free oil. Zero discharge is proposed as NSPS for produced sand. NSPS for sanitary wastes is being proposed equal to current BPT. NSPS for domestic wastes is proposed as equal to current practice prohibiting discharge of floating solids, plus the additional requirement for no visible discharge of foam.

XV. Revised Technology Costs and Assumptions

A. Drilling Fluids and Cuttings

In order to evaluate the cost of control technologies for drilling wastes, a database was established that defined:

- 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 levels 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 driling wastes, specifying pollutant concentration and physical properties of the waste specific to certain drilling scenarios.
- Failure rates of drilling wastes with respect to certain discharge limitations compliance tests (e.g., static sheen, toxicity).
- Disposal costs for transportation and land disposal of drilling wastes.

Table 16 summarizes the current permit requirements that were used as baseline requirements in the cost as well as economic analyses.

TABLE 16.—SUMMARY OF CURRENT REQUIREMENTS FOR DRILLING FLUIDS AND CUTTINGS FOR THE OFFSHORE PERMITS

Requirement	Gulf of Mexico	Pacific	Alaska
No discharge of oil-based drilling fluids and cuttings (BPT requirement).	Yes	Yes	Yes
Metals Limitation	No	Yes (barite)	Yes (barite)
—Mercury (mg/kg)		1	1
—Cadmium (mg/kg)		2	3
No discharge of oil in detectable amounts:			
—for Lubricity	Yes (Diesel)	Yes (Diesel)	Yes (Diesel)
—as a Pill	No [1]	No [1]	Yes (Mineral) [2]
Toxicity limitation	Yes	Yes	Yes [3]
Limit (drilling fluids)	30,000 ppm SPP	30,000 ppm SPP	
No discharge of "free oil"; static sheen test (cuttings from use of water-based drilling fluids).	No	Yes	Yes

SSP: Suspended Particulate Phase

[1] Diesel pill plus a 50 bbl. buffer of drilling fluid on either side of the pill cannot be discharged; mineral oil can be discharged without a buffer.

[2] Mineral oil pill plus a 50 bbl. buffer of drilling fluid on either side of the pill cannot be discharged. Diesel not allowed.

[3] With a pre-approved drilling fluid system.

Using these data, regulatory options, as defined in section XII, were evaluated to determine costs and pollutant removals associated with compliance with each of the options. In evaluating the cost of regulatory options, it was assumed that all drilling operations would utilize material substitution rather than have to take waste onshore for disposal. This includes substituting mineral oil for diesel and using "clean" barite. For the zero discharge options, however, such material substitution was not utilized.

An analysis of each option was conducted to determine:

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

Costs are presented on an annual basis only; no capital costs are presented, because no capital costs were identified for any of the drilling fluids and drill cuttings options. Compliance costs for each option are based on the cost of material substitution (e.g., mineral oil for diesel) or the cost of onshore disposal of drilling waste. No distinction was made between BAT and NSPS wells because it is estimated that all but approximately 4 percent of the wells will be considered new sources. The results of the analyses are presented in Table 17 for drilling fluids and drill cuttings combined.

TABLE 17.—ANNUAL COMPLIANCE COST/POLLUTANT REMOVALS FOR REGULATORY OPTIONS: DRILLING FLUIDS AND DRILL CUTTINGS COMBINED—NSPS AND BAT/BCT

	5/3 All	1/1 All	Zero discharge shallow; 5/3 deep	Zero discharge shallow; 1/1 deep	Zero discharge all	Zero at 4 mile; 5/3 beyond*	Zero at 4 mile; 1/1 beyond*
Cost of pollution removal ($1000/yr)	22,029	32,564	108,548	116,382	308,189	63,084	72,252
Volume of drilling fluid barged (1000/bbl/yr)	552	552	2,746	2,746	8,190	1,596	1,596
Priority pollutant removal (lb/yr)	29,000	34,840	364,494	367,000	965,000	193,000	183,500
Nonconventionals removal (lb/yr)	790,000	790,000	678,060	662,570	957,000	738,000	733,000
Oil removal (1000/lb/yr)	4,248	4,251	6,308	5,840	13,995	5,274	5,267
Incidental pollutant removal (lb/yr)	190,000	188,000	472,200	468,900	751,000	318,000	317,000

TABLE 17.—ANNUAL COMPLIANCE COST/POLLUTANT REMOVALS FOR REGULATORY OPTIONS: DRILLING FLUIDS AND DRILL CUTTINGS COMBINED—NSPS AND BAT/BCT—Continued

	5/3 All	1/1 All	Zero discharge shallow; 5/3 deep	Zero discharge shallow; 1/1 deep	Zero discharge all	Zero at 4 mile; 5/3 beyond*	Zero at 4 mile; 1/1 beyond*
Conventionals—TSS removal (10^6 lb/yr)	210	210	830	830	2,208	519	519

Notes:
1. Approximately 4 percent of the costs and removals are associated with new wells at existing structures covered by BCT/BAT.
2. All removals shown incremental to BPT.

* Excludes Alaska region from the zero discharge requirement.

In determining pollutant removals, specific pollutants were selected for evaluation based on their consistently significant presence in offshore oil and gas wastes. Removals are considered direct or incidental. The priority pollutants, conventionals, oil, and nonconventionals listed in Table 17 are pollutants directly removed by the technologies being evaluated. For the priority pollutants, pollutant removals were calculated on the sum total of concentrations for benzene, naphthalene, fluorene, phenanthrene, phenol, cadmium, mercury, antimony, arsenic, beryllium, chromium, copper, lead, nickel, selenium, silver, thallium, and zinc. The nonconventionals evaluated consisted of classes of organics including the alkylated homologs for benzene, naphthalene, biphenyl, fluorene, and phenanthrene, the alkylated phenols for ortho-cresol, meta- and para-cresol, C2 phenols, C3 phenols, and C4 phenols, and total dibenzothiophenes. An additional category labeled "incidental removal" was included to measure removals of pollutants be technologies not necessarily intending to remove them. These pollutants are the same as the priority pollutant metals and include cadmium, mercury, antimony, arsenic, beryllium, chromium, lead, nickel, selenium, silver, zinc, and thallium.

B. Produced Water

In order to evaluate regulatory options for discharge limitations on produced water associated with oil and gas extraction, a database was developed that defined:

• 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/NSPS treatment options.

• Cost to implement the BAT/NSPS treatment technology options.

Using these data, regulatory options were evaluated to define the cost and pollutant removals associated with compliance with the options defined earlier in section XII.

Two sets of treatment technologies were considered as BAT/NSPS model technologies: (1) Filtration and subsequent discharge, and (2) filtration followed by injection (or reinjection). Because calculations of cost/pollutant reductions on a platform-by-platform basis were considered impractical from a data collection standpoint, the industry was characterized as consisting of a platform population divided among "model platforms." These "model platforms" were considered typical of the industry and were differentiated based on the number of well slots on the platform, and in the case of one well platform, there was also a differentiation for those that pipe the produced fluids (or water) to a central offshore or land-based locality for processing and/or treatment.

For each "model platform" it was possible to predict 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," estimates of costs and pollutant reductions could be derived.

Contaminant removals were determined by comparing the estimated effluent levels after treatment by the BAT/NSPS treatment system (either filtration or reinjection) versus the effluent levels associated with a typical BPT treatment (gas flotation or gravity separation).

The cost to install a BAT/NSPS treatment system for each of the model platforms was estimated based on the maximum produced water flow rate over the life of the project and the cost of a treatment system designed to provide the needed capacity. Data were developed for treatment systems capital and annual costs over a range of flows, and the cost for each model platform was determined by interpolating within these data.

The results of the analysis are presented in Tables 18 for BAT and 19 for NSPS. Data are presented on number of platforms affected, capital, and annual compliance costs, and annual pollutant removals in terms of conventional, metal, and organic pollutants.

TABLE 18.—SUMMARY OF IMPLEMENTATION COSTS AND CONTAMINANT REMOVAL FOR PRODUCED WATERS—BAT

	No. of platforms	Capital cost ($)	Annual cost ($/yr)	Pollutant reduction (lb/yr)		
				Conventional	Metals	Organics
Filter and discharge shallow; BPT deep	1,309	172,850,302	44,248,123	11,006,000	249,000	510,000
Zero discharge shallow; BPT deep	1,309	1,258,707,237	76,194,925	18,101,000	255,000	575,000
Filter and discharge all	2,260	423,510,006	104,287,634	34,605,000	831,000	1,626,000
Zero discharge shallow; filter deep	2,260	1,517,366,941	136,154,436	41,700,000	837,000	1,690,000
Zero discharge	2,260	2,358,304,406	160,668,900	56,693,000	850,000	1,829,000
Filter and discharge 4 mile; BPT beyond	208	35,250,039	8,384,563	3,234,000	74,000	140,000

TABLE 19.—SUMMARY OF IMPLEMENTATION COSTS AND CONTAMINANT REMOVAL FOR PRODUCED WATERS—NSPS (UNCONSTRAINED DEVELOPMENT)

	No. of platforms	Capital cost ($)	Annual cost ($/yr)	Pollutant reduction (lb/yr)		
				Conventional	Metals	Organics
Filter and discharge shallow; BPT deep	393	104,874,421	22,108,417	6,599,000	142,000	312,000
Zero discharge shallow; BPT deep	393	607,540,177	35,937,583	10,894,000	145,000	346,000
Filter and discharge all	851	300,853,708	61,717,562	27,404,000	673,000	1,326,000
Zero discharge shallow; filter deep	851	803,519,464	75,626,728	31,698,000	677,000	1,359,000
Reinject all	851	1,300,307,478	89,509,755	44,850,000	688,000	1,465,000
Filter and discharge 4 mile; BPT beyond	162	63,827,101	12,696,327	6,362,449	136,751	276,393

XVI. Economic Analysis

A. Introduction

The Agency's economic impact assessment is presented in the "Economic Impact Analysis of Proposed 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 and on typical companies involved in offshore oil and gas drilling and production. The report also estimates the economic effect of compliance costs on production, Federal and State revenues and discusses the impact on the balance of trade and inflation. (In this report, as in the section following, unless otherwise indicated, all costs are in 1986 dollars.)

EPA has also conducted an analysis of the cost-effectiveness of alternative treatment options. The results of this cost-effectiveness analysis are expressed in terms of the incremental costs per pound-equivalent. Pound-equivalents account for the differences in toxicity among the pollutants removed. The number of pounds of a pollutant removed by each option is multiplied 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 pounds-equivalent removed by that option. This analysis, "Cost-Effectiveness Analysis of Proposed Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry" (hereinafter, "Cost-Effectiveness Report"), is included in the record of this rulemaking. Copies of this report and of the Economic Impact Analysis cited above may be obtained from the economic analysis staff. (See the ADDRESSES section of today's notice.)

B. Costs and Economic Impacts

1. Basis of Analysis

The costs and economic impacts of today's proposed regulations cover two major waste streams: (1) Drilling fluids and drill cuttings associated with drilling operations; and (2) produced waters associated with production operations. (Incremental treatment requirements for miscellaneous waste streams create little or no additional costs and so the impacts of those costs are not analyzed separately here.)

The economic analysis of drilling operations is based on the average number of exploratory, delineation and development wells that the Agency estimates will be drilled each year through the year 2000. Only a small percentage of those wells are estimated to be BAT wells, i.e., wells drilled on existing platforms. The cost of controlling the pollution from drilling operations is estimated to be the same, on a per well basis, for BAT and NSPS wells.

The economic analysis of production operations is based on the number of offshore platforms producing in 1986 and on the Agency's projections of the number of platforms to be built between 1986 and the year 2000. By the year 2000, new source oil and gas development is expected to be stabilized, i.e., in that year, the number of new platforms beginning production should equal the number of obsolescent platforms being retired.

The basis of the economic analysis has changed in part since the 1985 proposal, in response to new data and to comments received on that proposal and on the 1988 Notice of Data Availability. The changes include:

(1) Data from the Minerals Management Service (NMS), are used instead of Department of Energy (DOE) data to estimate the number of new wells and platforms. MMS data are an improvement over DOE data because MMS data are regionalized and include projections beyond the year 2000.

(2) In the 1985 proposal, the projections of the number and type of offshore facilities were based on an expected average price of $32 per barrel of oil (bbl) ($1,986). The current projections are based on an average of $21 per bbl with sensitivity analyses at $15 and $32 per bbl ($1,986).

(3) In response to comments on the 1988 Notice, the Agency now includes a one-well model platform. One-well platforms comprise about 20 percent of the facilities in the Gulf of Mexico. (Previously, the Agency's smallest model facility was a four-well platform.)

(4) Treatment costs are now regionalized. (Previously, only the economic impact models were regionalized.)

(5) Costs and impacts for BAT and NSPS are now estimated from "current," as defined by the current regional permit requirements. Previously, NSPS and BAT were defined as incremental to BPT, not current. This change only affects the treatment requirements for drilling fluids and drill cuttings; regional permits for produced water do not require controls above BPT.

(6) The estimated number of offshore wells and platforms (based on $21 per bbl) are presented below. Estimates of constrained development are presented to reflect current constraints on leasing and drilling in the Pacific and the lack of Atlantic development. Unconstrained development estimates assume no constraints on Pacific drilling and some Atlantic drilling.

The following discussion of costs and economic impacts assumes $21 per bbl, constrained development, and for produced water, membrane filtration. The EIA and Cost-Effectiveness Reports also include sensitivity analyses of costs and impacts based on $15 and $32 per bbl, unconstrained development, and granular filtration.

Assuming $21 per bbl the Agency estimates:

Wells Drilled, NSPS:

—759 per year, Constrained Development;

—980 per year, Unconstrained Development.

These well counts presented as NSPS are the total wells drilled during the period 1986 to 2000 divided by 15 years to give the annual average number of wells drilled. The Agency does not have data on which to base a precise estimate of the number of wells drilled on existing platforms. However, the Agency estimates that with restricted development about 1 percent of the wells drilled will, in fact, be BAT wells drilled on existing platforms. Typically, these BAT wells will be on the larger platforms that have not completed their drilling program when this regulation goes into effect. The drilling of BAT wells will, therefore, be concentrated in the first years after promulgation of this regulation as the larger existing platforms complete multiple-year drilling programs. As a result, most of the cost for these BAT wells will be incurred in the first years after the regulation goes into effect. The number of BAT wells drilled will be highest in the first year after the regulation and will decline thereafter. Five years after the regulation goes into effect, few or no BAT wells will be drilled.

The Agency's estimates of total platforms are as follows:

Platforms, NSPS:

—766 total, 1986–2000, Constrained Development;

—851 total, 1986–2000, Unconstrained Development;

Platforms, BAT: 2260.

Note that the number of platforms are *total* currently producing and the *total* projected to be installed during the period 1986 to 2000 while the number of wells drilled is presented as *annual* average.

The number of offshore wells drilled annually that are within four miles of shore and, therefore, will be affected by the proposed zero discharge option are as follows:

Wells Drilled, NSPA:

—81 (11 percent of 759), Constrained Development;

—152 (16 percent of 980), Unconstrained Development.

As explained above, the only site of BAT wells would be on the larger platforms, and, under constrained development, few of the larger platforms are within four miles of shore. Under constrained development, the Agency estimates that, at most, only a total number of 100 BAT wells will be drilled within four miles of shore during the period 1986–2000.

The number of platforms within four miles of shore which are assumed to filter prior to discharge to meet the proposed limitations on produced waters are as follows:

Platforms, NSPA:

—142 (19 percent of 766), 1986–2000, Constrained Development;

—162 (19 percent of 851), 1986–2000, Unconstrained Development

Platforms, BAT: 208 (9 percent of 2260).

2. Total Costs and Impacts of Proposed Regulations

The combined annualized cost of the preferred options proposed today for BCT, BAT and NSPS for both major waste streams is $54 to $80 million. (The lower total costs reflect constrained development; the higher cost, unconstrained development of offshore energy resources.) For purposes of estimating costs and impacts, zero discharge for drilling fluids and drill cuttings, is assumed to be achieved by barging. For produced water, zero discharge is assumed to be achieved by reinjection and the limitations greater than BPT but less stringent than zero discharge are assumed to be achieved by membrane filtration prior to discharge. The capital investment for the proposed requirements is limited to produced water control. (No capital investment is associated with the barging of fluids and cuttings. Barging, land transportation and disposal is a service supplied to the oil and gas companies that are drilling offshore wells.) Total capital investment for the preferred BAT option for produced water is $35 million. Total capital investment for the preferred NSPS requirement for produced water is $64 million.

The combined impact of the preferred options for drilling fluids and drill cuttings and for produced water would reduce the working capital of a typical major offshore oil and gas company by 0.2 percent and the working capital of a typical independent company by 1.9 percent. (Working capital is the parameter most sensitive to increased costs.)

The potential loss in the present value of future production of oil and gas as a result of the preferred options is minimal. The preferred option for drilling fluids and drill cuttings has no impact on production. The preferred BAT and NSPS options for control of produced water is projected to result in a potential loss of 2 million barrels of oil equivalent (BOE) due to premature shut downs of wells. (BOE is a standard measure of energy-equivalent.) The shut downs are projected to occur because the regulation increases the cost of option and shortens the economic life of some platforms. This loss represents a small percentage (0.02 percent) of 11.7 billion BOE, the present value of offshore production during the period 1986–2000.

The preferred options potentially could result in an $50 million loss to federal revenues (through tax effects and lower lease bids) and a $3 million loss to state revenues (through lower lease bids). The impact of this potential loss is minimal, representing, for example, less than 0.01 percent of total state revenues in Texas. Furthermore, these losses are only potential: companies may not choose to recoup all the cost increase from the proposed regulation through lower lease bids. If lease bids are too low, companies might not win the lease. Under these circumstances, companies may absorb the cost increase through reductions in profits.

The proposed regulations are not expected to impact energy prices, inflation, employment or international trade. The preferred options may, in fact, lead to temporary positive impacts on the offshore service industry due to the need to retrofit existing facilities with filtration equipment. The Agency finds the costs of the proposed BAT and NSPS regulations to be economically achievable for the oil and gas industry.

3. Economic Methodology

The Agency used a net present value analysis to calculate whether offshore development operations could remain profitable after regulatory costs were incurred. First, costs and revenues were projected over the life of the model project based on the current, or baseline, requirements. (The life of a project varies among the model projects.) Then the regulatory costs were added to those baseline costs to determine if the model platforms remained profitable. EPA used 34 model platforms to represent the diversity in offshore platform size (i.e., the number of well slots per platform), geographic location (Gulf of Mexico, Pacific, Alaska, and Atlantic coasts), and production type (oil only, gas only or both). Distinct technical and economic characteristics for each model were developed. Costs included in the baseline were those associated with exploration, delineation, development production operations, as well as the costs needed to meet current regional permit requirements.

To assess the impact on offshore oil and gas companies operating in the offshore area, the Agency developed two representative company financial profiles: One for major integrated companies and one for independents. Pre- and post-regulation balance sheets were developed and the effect of regulatory costs on the typical major and on the typical independent companies was then analyzed.

4. Costs and Impacts of Best Conventional Pollutant Control Technology

Section XII presents proposed BCT options. For drilling fluids and drill cuttings, the preferred option requires zero discharge for wells at four miles or less from the shore. For purposes of costing, this requirement is assumed to be achieved by barging of fluids and cuttings for transportation and disposal on land. On a per-well basis, barging costs are the same for BCT, BAT, and NSPS. The preferred options for BCT, BAT and NSPS all require zero discharge for wells drilled within four miles of shore; costing for BCT, BAT, and NSPS all assumed, for purposes of costing, that zero discharge would be achieved by barging. For wells drilled beyond four miles of shore, BAT and NSPS costs include monitoring for and control of toxics; BCT costs do not. As explained above, at most a total of 100 BAT wells are projected to be drilled on the existing platforms that are four or less miles from shore. Thus, for the preferred BCT option, at most, total (not annualized) BCT costs would not exceed $350 million for the period 1986 to 2000. Most of these costs would be incurred in the first years after the regulation goes into effect. On a per-well or per-projected basis, BCT costs equal BAT/NSPS costs. According to the Agency's analysis, BAT/NSPS costs are economically achievable. Consequently, the BCT costs are also economically achievable.

As discussed in section XII above, for produced water, BCT equals BPT. Therefore, for produced water, there are no incremental costs for BCT and no economic impacts.

5. Costs and Impacts of Best Achievable Technology

a. *Drilling Fluids and Drill Cuttings.* The Agency estimates that during the period 1986–2000, at most, only a total of 100 wells drilled offshore will be on existing platforms located within four miles of shore and thus subject to the proposed BAT regulation of zero discharge. For purposes of costing and estimating impacts, wells required to meet zero discharge are assumed to barge fluids and cuttings to shore; wells beyond four miles are to meet the limitations described in section XIII.A.2 above (the 1/1 option). On a per-well-basis, the average cost of barging from a BAT well drilled on an existing platform is expected to be equal to the cost of barging from an NSPS well, or an average of $350 thousand per well drilled (assuming restricted development). This per-well cost includes barging, land transportation, and land disposal of fluids and cuttings from wells within four miles from shore. For wells drilled beyond four miles of shore, the costs of compliance include monitoring, the cost of substituting mineral oil for diesel oil for spotting and lubricity and the cost of "clean" barite to meet the limitations on cadmium and mercury in the drilling fluids. The costs of the preferred option are incremental to current permit requirements.

Most of the wells drilled on existing platforms will be on the larger platforms (i.e., those with more well-slots). These large platforms will not have completed their drilling programs at the time the regulation goes into effect, but they will do so in the first few years of the regulation. Therefore, the economic impact of BAT regulations on drilling fluids and drill cuttings will be concentrated in the first five or so years after the regulation goes into effect. After five years, few, if any, wells will be drilled on existing platforms.

No capital investment will be needed to meet the preferred limitations on drilling fluids and drill cuttings because oil companies that drill offshore typically do not purchase barges, but instead contract for that service. In this analysis, BAT costs are included in the total annualized NSPS. Total (i.e., not annualized) BAT costs of $350 million are based on an estimated total of 100 wells will be drilled in the first five years after this regulation goes into effect.

According to the Agency's analysis, the economic impact of the proposed BAT option for drilling fluids and drill cuttings is the same as the impact of the NSPS, which are discussed below. The costs of the proposed BAT regulation of drilling fluids and drill cuttings are economically achievable.

b. *Produced Waters.* The Agency estimates that 2,260 offshore platforms currently are producing either oil or gas or both. Of these, 208 platforms are within four miles of shore and therefore, under the preferred option, will be subject to limitations beyond BPT for produced waters (as described in sections XII.C.1 and XIII.C.2, above). For purposes of estimating costs and impacts, the Agency assumed the limitations on existing platforms within four miles of shore would be achieved by membrane filtration of produced water prior to discharge. Platforms beyond four miles would be subject to BPT.

Total capital costs of the BAT preferred option are estimated to be $35 million. Annual operating and maintenance costs of $8 million include monitoring at all platforms and filtration of produced waters at those platforms within four miles of shore. The annualized incremental costs of the BAT options considered for produced water range between $13 million and $491 million. The annualized incremental cost of the proposed option is $13 million.

The EIA includes impacts of the options considered on each type of model platform. Selected impacts are presented here: Impacts on the Gulf-12 platform are typical of impacts on the industry; impacts on the Gulf one-well model platforms are presented here because these small platforms are most sensitive to impacts of the regulation.

For existing oil and gas Gulf-12 platforms four miles or less from shore, the BAT preferred (filtration) option increases the corporate cost per BOE 1.6 percent and decreases the net present value of the project 4.7 percent. The platform's production is decreased 11 percent because it would shutdown a year early.

For existing one-well platforms in the Gulf of Mexico that produce oil and gas and have their own production equipment, the BAT preferred option increases the corporate cost per BOE 14 percent and decreases the net present value of the project 27 percent. The platform's production is decreased 22 percent because it would shutdown two years early. (See impacts on Gulf 1B's in the EIA.)

The preferred BAT option would have virtually no impact on the working capital of a typical major company that is involved in offshore energy production and would reduce the working capital of a typical independent company by 0.5 percent. According to the Agency's analysis, the preferred option would have no effect on oil and gas prices, employment, or international trade. The Agency finds the costs of the preferred BAT option for control of produced waters to be economically achievable for the oil and gas industry.

6. Costs and Impacts of New Source Performance Standards

a. *Drilling Fluids and Drill Cuttings.* Of the 759 exploratory, delineation, and development wells projected to be drilled each year 1986–2000 under constrained offshore development, 81 (or 11 percent) will be on new platforms and thus subject to the NSPS proposed option. For purposes of costing and impacts, the Agency assumes wells drilled within four miles of shore will meet the zero discharge limitation by barging; wells drilled beyond four miles will meet limitations described previously as the "1/1" option.

The total annualized incremental costs of regulating drilling fluids and drill cuttings range between $0.8 million and $211 million. The annualized incremental cost of the preferred option is $29.5 million. (As explained above, for fluids and cuttings, these costs are operating and maintenance costs, including monitoring; there are no capital costs associated with any options considered for these waste streams.)

For new oil and gas wells drilled on Gulf-12 platforms four miles or less from shore, the preferred NSPS option increases the corporate cost per BOE 0.2 percent and decreases the net present value of the project 0.9 percent. For new oil and gas wells drilled in the Gulf on one-well platforms that have their own production equipment, option increases the corporate cost per BOE 0.7 percent and decreases the net present value of the project 11.5 percent. (See impacts on the Gulf 1B's in the EIA.)

None of the options considered for drilling fluids and drill cuttings have an adverse impact on production.

The preferred option would reduce the working capital of a typical major company that is involved in offshore energy production by 0.1 percent and the working capital of a typical independent company by 1.0 percent. According to the Agency's analysis, the preferred option would have no effect on oil and gas prices, employment, or international trade. The Agency finds the costs of the preferred NSPS option for fluids and cuttings are economically achievable.

b. *Produced Water.* Of the 766 platforms projected to be installed offshore between 1986 and the year 2000, assuming constrained offshore development, 142 are estimated to be four or less miles from shore and therefore, under the preferred option, will be subject to limitations beyond BPT for produced water (as described in sections XII.C.1 and XIII.C.2, above). For purposes of estimating costs and impacts, the Agency assumed the limitations on new platforms within four miles of shore would be achieved by membrane filtration of produced water prior to discharge. Platforms beyond four miles would be subject to BPT.

Total capital costs of the NSPS preferred option are estimated to be $41 million ($64 million for the unconstrained scenario). Annual operating and maintenance costs of $8 million ($13 million for the unconstrained scenario) include monitoring at all platforms and filtration of produced waters at those platforms within four miles of shore. The annualized incremental cost of the NSPS options considered for produced water range between $11 million and $158 million. The annualized incremental costs of the preferred option is $11 million ($17 million for the unconstrained scenario).

For new oil and gas Gulf-12 platforms four miles or less from shore, the preferred NSPS membrane filtration option increases the corporate cost per BOE 0.6 percent and decreases the net present value of the project 2.2 percent. The preferred NSPS option for produced water has no adverse impact on production from Gulf-12 platforms. (Production on most model platforms, in fact, is not adversely impacted by NSPS for produced waters.)

For the projected NSPS one-well platforms in the Gulf that produce oil and gas and have their own production equipment, the preferred membrane filtration option increases the corporate cost per BOE by 2.7 percent and decreases the present value of the project by 69 percent. Production on these platforms would decrease 10 percent because they would shut down two years earlier than normal.

The preferred NSPS option for produced water would have virtually no impact on the working capital of a typical major company that is involved in offshore energy production and would reduce the working capital of a typical independent by only 0.4 percent. According to the Agency's analysis, the preferred option would have no effect on oil and gas prices, employment, or international trade. The Agency finds the costs of the proposed NSPS regulation of produced waters to be economically achievable for the oil and gas industry.

C. Cost-Effectiveness Analysis

In addition to the foregoing analyses, the Agency has performed a cost-effectiveness analysis for each of the proposed options. According to the Agency'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. The pounds-equivalent removed for each option considered were calculated by weighting the number of pounds of each pollutant removed for each option by the relative toxic weighting factor for each pollutant. The use of "pounds-equivalent" gives relatively more weight to removal of more highly toxic pollutants. Thus for a given expenditure, the cost per pound-equivalent would be lower when a highly toxic pollutant is removed than if a less toxic pollutant is removed. 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.

For the selected options (in $1981), the incremental cost effectiveness is $22 per pound-equivalent for drilling fluids and drill cuttings; $60 per pound-equivalent for produced waters, BAT, and $63 per pound-equivalent for produced waters, NSPS. The Cost-Effectiveness Report, which is available in the record of this rulemaking, describes the cost effectiveness calculations in detail and presents the pollutants included in the cost-effectiveness analysis, the toxic weights used for each pollutant, and sensitivity analyses for such variables as unconstrained development, alternative energy values of $15 and $32 per bbl, and use of granular filtration.

These cost-effectiveness values reflect the Agency's standard cost-effectiveness methodology. In the majority of the Agency's effluent guideline regulations developed to date, the discharges have been to fresh waters (directly or indirectly via publicly owned treatment works). In this case the discharges are to marine waters. As described below in section XVII, the Agency has had some difficulty assessing the benefits of this regulation due to the nature of the waters affected by discharges from offshore platforms. For this reason, the Agency is requesting comment concerning the procedures that can be used to assess the value of controlling discharges to these different waters for the purposes of benefit analyses. (See section XIX of today's notice.)

D. Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980, Public Law 96-354, requires that the Agency prepare an initial Regulatory Flexibility Analysis (RFA) for all proposed regulations that have a significant 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 the Agency. The purpose of the Act is to ensure that, while achieving the Agency's statutory goals, the Agency's regulations do not impose unnecessary costs on small entities.

The economic impact analysis described above indicates that the expenditures necessary to meet the proposed limitations and guidelines for the offshore oil and gas industry will be financed by major and independent oil companies. These are not "small businesses" by any standard. Additionally, the analysis has determined that none of the companies directly affected by this regulation are small businesses. Therefore, a formal Regulatory Flexibility Analysis is not required.

E. Paperwork Reduction Act

This proposed rule will impose no increase in reporting or recordkeeping burden to respondents as covered under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The proposed rule contains no information collection provisions.

XVII. Executive Order 12291

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 on the economy 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 the Office of Management and Budget (OMB) for review, as required by Executive Order 12291.

Three types of benefits were analyzed in this RIA: Quantified and monetized benefits; quantified and non-monetized benefits; non-quantified and non-monetized 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 were found to be reasonably commensurate with their costs. The total monetized benefits for the selected options (1986 dollars: Gulf of Mexico only) range from $13.4 to $65.2 million annually. The total annualized BAT and NSPS costs (1986 dollars; Gulf of Mexico only) range from $47.4 to $67.6 million for drilling fluids, drill cuttings, and produced water. (The primary difference in the cost range reflects membrane filtration at the low end and granular filtration at the high end.)

Monetized benefits were based solely on health-related impacts. Benefits associated with regulating drilling fluids and cuttings greatly predominated over those associated with regulating produced water; for drilling fluids and cuttings, lead-related health benefits greatly predominated over carcinogen-related health benefits. The quantified, non-monetized benefits assessment included a review of case studies of environmental impacts of drilling fluids and cuttings and produced water that documented adverse chemical and biological impacts result from discharges of these wastes. In addition, a water quality analysis was prepared that for selected options projected decreases in the number of pollutants exhibiting water quality criteria exceedances as well as the magnitude of these exceedances.

The RIA contains an analysis of the effect of the proposed regulations for major waste streams from offshore oil and gas exploration (i.e., drilling muds and cuttings), and production activities (i.e., produced water) on existing marine water quality. The analysis for these waste streams has two parts.

The first part of the RIA summarizes case studies of local impacts found near oil and gas platforms located in the Gulf of Mexico, in water off California and Alaska. A comprehensive review of available data (over 800 references, plus EPA's Ocean Data Evaluation System (ODES) database) shows documented local impacts for drilling muds and cuttings (18 case studies) and for produced water discharges (seven case studies). Widespread marine impacts were not well documented.

Discharged muds and cuttings are shown to cause contamination of sediments with heavy metals and hydrocarbons known to be present in these discharges up to 4,000 meters from the platforms. Other documented impacts include declined abundance in benthic species (up to 1000 m from the platform), reduced bryozoan coverage (within 2000 m of discharge), altered benthic communities (up to 300 m from platform), bioaccumulation of heavy metals known to be present in drilling muds and cuttings by benthic organisms, complete elimination of seagrass (within 300 m of discharge) inhibited growth of seagrass (up to 3,700 m distance) and decreased coral coverage.

Produced water discharges are shown to cause contamination of sediments with polynuclear aromatic hydrocarbons (PAH) up to 3000 m from the platforms. Other significant impacts include complete elimination of benthic organisms up to 400 m from the platform, depressed abundance of benthic species up to 5000 m, and alteration of benthic communities (mostly toward opportunistic species).

The second part of the RIA uses modeling to project water quality impacts/benefits for existing and new Outer Continental Shelf (OCS) oil and gas platforms in the Gulf of Mexico. The current "baseline" and considered BAT and NSPS options are assessed. EPA's published marine water quality criteria are used to assess water quality impacts. The human health risk/benefits from consumption of fish and shellfish exposed to the OCS oil and gas platform discharges in the Gulf of Mexico area are also assessed. The Gulf of Mexico was selected as a case study area because of its majority of the offshore oil and gas exploration and production activities, as well as its extensive and abundant commercial and recreational fishing activities.

The RIA attempts to monetize the specific health and environmental benefits that may result from the proposed regulations. However, the extent of dilution afforded by the marine environment resulted in modeled concentrations for the selected average industry-wide pollutants so low that under current regulatory controls no direct quantifiable impacts on the Gulf of Mexico fishery can be attributed to the platform-related discharges. Predictions could not be made to quantify direct impacts of current discharges and proposed regulations on: composition and abundance of fin fish and shellfish population; recreational fishing and other recreational activities; commercial fishing; or nonuse benefits. Therefore, the RIA focuses almost exclusively on the benefits associated with human health risk reduction through reduced concentration of platform-related pollutants in selected recreational fish species and commercial shrimp. Both carcinogenic and systemic human toxicants 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 under consideration.

A. Produced Water

Water quality impacts are projected for granular filtration on the basis of eight pollutants representing average industry-wide production discharges; for membrane filtration, impacts are projected on the basis of 23 pollutants. The membrane filtration analysis project two pollutants (arsenic and bis(2-ethylhexyl) phthalate) exceeding human health criteria for fish consumption. Granular filtration analysis projects that one pollutant (bis(2-ethylhexyl) phthalate) exceeds human health criteria. None of the pollutants modeled exceeds marine aquatic life criteria at the current discharge (BPT). The preferred BAT and NSPS options will not completely eliminate these human health criteria exceedances but will reduce the magnitude of the impact.

Determination of the cost/benefit analysis for both the membrane and granular filtration technologies has been restricted by the limited amount of published quantifiable human health data for the majority of pollutants of concern. As a result, human health benefits have been underestimated. The cost/benefit analysis for membrane filtration was limited to analysis of three pollutants (arsenic, benzene, and bis(2-ethylhexyl) phthalate), while the granular filtration analysis included only two pollutants (benzene and bis(2-ethylhexyl) phthalate).

Based on these limitations in the analysis, human health benefits are estimated to range between $1,000 and $6,000 per year for the proposed BAT option using membrane filtration in the Gulf of Mexico, compared with a projected incremental annualized cost of $9 million for membrane filtration in the Gulf. These monetized benefits are based on the average risk reduction associated with the consumption of platform-contaminated fish and shrimp for the three carcinogens noted above. The risk reduction projections are derived from flow-weighted industry-wide average pollutant concentrations. Monetized human health benefits due to removals of the two carcinogens associated with the proposed BAT option using granular filtration range between $2,000 and $9,000 per year in the Gulf of Mexico. The risk reduction projections for granular filtration are based on concentrations for individual production groups (oil only, gas only, oil and gas). The annualized costs for the proposed BAT option are $24 million for the Gulf. The estimated annualized human health benefits in the Gulf of Mexico for the proposed NSPS option (based on the same pollutants and methodology) are estimated to range from $300 to $2,000 for membrane filtration and from $200 to $1,000 for granular filtration. These NSPS benefits compare with NSPS annualized costs for the Gulf of $9 million (membrane filtration) and $14 million (granular filtration) (1986 dollars) (Table 20). 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 in the RIA.

TABLE 20—INCREMENTAL ANNUALIZED BENEFITS AND COSTS FOR PRODUCED WATER BAT/NSPS OPTIONS

[Thousands of 1986 dollars per year; Gulf of Mexico only]

Regulatory option	Produced water BAT options				Produced water NSPS options			
	Incremental benefits		Incremental costs		Incremental benefits		Incremental costs	
	Membrane filter	Granular filter	Membrane filter	Granular filter	Membrane filter	Granular filter	Membrane filter	Granular filter
BPT all	0	0	0	0	0	0	0	0
Four mile filter; BPT beyond*	1–6	2–9	8,787	24,287	0.3–2	0.2–1	9,079	13,842
Filter shallow; BPT deep	N/A	4–22	59,378	N/A	N/A	3–13	26,236	N/A
Filter and discharge all	N/A	6–31	139,609	438,067	N/A	3–16	56,558	86,845
Zero discharge shallow; BPT deep	N/A	5–23	247,095	N/A	N/A	3–14	81,398	N/A
Zero discharge shallow; filter deep	N/A	6–31	327,326	N/A	N/A	3–17	111,629	N/A
Zero discharge all	N/A	6–32	458,736	776,772	N/A	3–17	145,572	186,608

Notes:
1. All incremental values relative to current (BPT) treatment level.
2. Incremental benefits reflect monetized health benefits only. Membrane filter benefit projections derived from industry-wide flow-weighted averages for 3 carcinogens are not directly comparable to granular filter projections based on individual production groups for 2 carcinogens.
*Preferred option in today's notice.
N/A: Not Available.

Neither analysis for granular or membrane filtration considers impacts of various additives, especially biocides, due to the lack of specific data on the actual use/discharge of these components by the industry. EPA identified only a limited number of the biocides as actually used by the industry. Many of the biocides registered by EPA's Office of Pesticides and Toxic Substances, or identified as used by the industry, are highly toxic to marine aquatic life, and others are carcinogenic. These pollutants may cause adverse impacts on the marine environment and/or human health through fish consumption if discharged in sufficient quantities. EPA expects to collect additional pollutant data, and data on actual use/discharge of biocides and other toxic additives, prior to final promulgation to more precisely characterize average industry-wide discharges. EPA is also soliciting new information on produced water characteristics, and environmental impacts associated with discharges of these wastes into the marine environment.

The impacts of radioactive pollutants in produced water (e.g., radium-226 and radium-228) are not evaluated for either filtration technology although they have been identified in produced waters in the Gulf of Mexico region. These radioactive pollutants are known human carcinogens and are known to bioaccumulate in fish and shellfish. These pollutants have a potential to cause human health impacts through fish consumption. Recent data from a coastal Louisiana study show these pollutants to accumulate in the sediments, as well as caged oysters.

However, data are lacking on the fate and impacts of these pollutants in the offshore environment which precludes a complete assessment of potential human health risks and projected benefits associated with controlling the discharge of these pollutants at this time. EPA is concerned about these impacts, however, and expects to collect additional data on discharges of radioactive pollutants by the offshore subcategory, and on the removal efficiency of the existing control technologies prior to final promulgation. This new information will be used to project potential environmental impacts and regulatory benefits for the final RIA. EPA is also soliciting information on discharge levels of these pollutants, their fate in the marine environment, as well as data on the known environmental impacts in the offshore environment.

B. Drilling Fluids and Drill Cuttings

Water quality impacts/benefits are projected for eight pollutants representing average industry-wide drilling discharges. The analysis indicates that two pollutants (lead and mercury) exceed marine aquatic life criteria, and two pollutants (arsenic and mercury) exceed human health criteria for fish consumption under current discharge conditions. The preferred BAT/NSPS option will eliminate these violations from the more environmentally sensitive shallow water areas, as well as reduce the number of pollutants with projected exceedances to one (mercury) for marine aquatic life criteria and one (arsenic) for human health criteria for fish consumption.

The estimated human health benefits for the preferred BAT/NSPS option based on the combined quantified average risk reduction associated with consumption of platform contaminated fish and shrimp by lead and arsenic are in the range of $13.4 million to $65.2 million, versus a projected incremental annualized cost of $29.5 million (1986 dollars). (Table 21) An additional reduction in human health risk due to the subsistence fishing near the platforms in the Gulf of Mexico region is also anticipated but cannot be quantified by the preliminary RIA.

TABLE 21—INCREMENTAL ANNUALIZED BENEFITS AND COSTS FOR DRILLING FLUIDS AND CUTTINGS BAT/NSPS OPTIONS

[thousands of 1986 dollars per year; Gulf of Mexico only]

Regulatory option	Incremental benefit	Incremental cost
5/3 All [1]	N/C	787
1/1 All	13,431–65,184–65,381	8,466
Zero discharge 4 miles; 5/3 beyond	12,396–60,381	22,493
Zero discharge 4 miles; 1/1 beyond [2]	13,341–65,184	29,500
Zero discharge shallow; 5/3 deep	12,584–60,856	81,119
Zero discharge shallow; 1/1 deep	13,431–65,185	86,279
Zero discharge all	13,432–65,188	211,859

NOTES

1. All incremental values relative to current treatment level.

2. Incremental benefits reflect monetized benefits only.

3. Current treatment assumed to be equivalent to "5/3 All" option for analytic purposes.

[1] Current treatment assumed to be equivalent to "5/3 All" option for analytic purposes. Incremental costs incurred are due to monitoring requirements.

[2] Preferred option in today's notice.

N/C: Not Calculated.

The water quality analysis and cost/benefit analysis for drilling fluids and cuttings underestimates the benefits derived from the proposed regulation by considering impacts of only eight pollutants to represent average industry-wide drilling discharges. Pollutants detected only in limited number of samples, are not considered to be industry-wide pollutants, and are therefore not considered in the preliminary RIA. Some of these non-considered pollutants are toxic to the marine life and/or human health and may cause local chronic or sub-chronic marine life or human health impacts around the platforms if discharged in sufficient quantities. EPA expects to collect additional pollutant data prior to final promulgation to more precisely characterize average industry-wide discharges. These pollutants will be included in water quality and cost/benefit analysis for the final promulgation. EPA is also soliciting new information on drilling waste characteristics, and environmental impacts associated with discharges of these waste streams into the marine environment.

XVIII. Non-Water Quality Environmental Impacts and Other Factors

A. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution may aggravate other environmental problems. Therefore, sections 304(b) and 306 of the Act require the Agency to consider the non-water quality environmental impacts (including energy requirements) of certain regulations. In compliance with these provisions, the Agency has evaluated the effect of the options being considered for the proposed regulations on air pollution, solid waste generation and management, and energy consumption.

The following is a description of the non-water quality environmental impacts associated with the options considered for today's proposed regulations and a summary of the results of the evaluations identifying the estimated levels and impacts for each of the considered options.

1. Energy Requirements and Air Emissions

Some of the proposed options are estimated to result in the generation of significant amounts of air emissions and the use of significant amounts of additional energy to comply with the additional treatment and control requirements for drilling fluids and drill cuttings and produced water.

Energy requirements and resulting air emissions for the control options considered by EPA are presented in Table 22 for drilling wastes and in Table 23 for the production wastes. Estimates are incremented to BPT. Thus, for example, the "5/3 All" estimates should approximate the energy requirements and air emissions associated with the requirements of existing permits. Presently, there are no national standards that directly regulate emissions from offshore oil and gas facilities. However, pursuant to the Clean Air Act Amendments of 1990, specific requirements are to be issued within a year controlling air emissions from OCS sources located offshore of the states along the Pacific, Arctic, and Atlantic coasts and along the Gulf coast off the state of Florida. The majority of offshore oil and gas activities, which are in the Gulf of Mexico offshore of Louisiana, Texas, etc., are not included in the coverage of these upcoming requirements. 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 power, either on the structures or for the purpose of transportation to and from the structures.

TABLE 22—NON-WATER QUALITY ENVIRONMENTAL IMPACTS: UNCONSTRAINED DEVELOPMENT

Options	Volume of barged waste (bbl/yr)	Air emissions (short tons/yr)	Fuel requirements (BOE/yr)
Drilling Fluids and Cuttings			
5/3 all structures	552,000	532	79,517
1/1 all structrues	552.000	532	79,517
Four mile zero discharge; 5/3 beyond [1]	1,596,000	1,166	173,360
Four mile zero discharge; 1/1 beyond [1]	1,596,000	1,166	173,360
Zero discharge shallow; 5/3 deep	2,746,000	2,116	293,535
Zero discharge shallow; 1/1 deep	2,746,000	2,116	293,535

TABLE 22—NON-WATER QUALITY ENVIRONMENTAL IMPACTS: UNCONSTRAINED DEVELOPMENT—Continued

Options	Volume of barged waste (bbl/yr)	Air emissions (short tons/yr)	Fuel requirements (BOE/yr)
Zero discharge; all structures	8,190,000	6,352	818,029

BOE: Barrel of Oil Equivalent.
[1] Excludes Alaska region from the zero discharge requirement.

For drilling fluids and drill cuttings, the only technology under consideration that has significant energy consumption impact is the use of barges to transport waste solids to shore and land transportation of land disposal of these wastes. Table 22 summarizes the fuel requirements and resulting air emissions for this option.

Air emissions are calculated for sulfur dioxide (SO_2), carbon dioxide (CO_2), hydrocarbons (HC), and nitrogen oxides (NO_x). These calculations are incremental to BPT and assume all oil-based drilling fluids and drill cuttings have either been substituted for or are being disposed of by shipment to land. The methodology used for the fuel consumption and emission calculations are described in the development documents.

Materials barged for the "5/3 All" and the "1/1 All" options are those that would normally require barging (i.e., do not comply with the required effluent limits). As can be seen by the table, a zero discharge requirement, whether applicable to all of the structures or to those structures located in shallow water depth, significantly increases the amount of barged material and resulting fuel consumption and air emissions.

The non-water quality environmental impacts related to the produced water options are shown in Table 23. The opertions requireing zero discharge for produced water greatly increase air emissions and fueld requirements as compared to those of the filtration and discharge options. This is due primarily to the energy required of reinjection equality in order to pump fluids into formations.

TABLE 23—NON-WATER QUALITY ENVIRONMENTAL IMPACTS: UNCONSTRAINED DEVELOPMENT

[Produced Water]

Option	Fuel requirements (BOE/year)		Total emissions (short tons/year)	
	BAT	NSPS	BAT	NSPS
Filter and discharge; 4 miles; BPT deep	5,490	10,920	9	18
Filter shallow; BPT deep	19,190	11,440	32	19
Filter and discharge; all	58,980	46,650	97	77
Zero discharge shallow; BPT deep	709,510	422,540	1,178	702
Zero discharge shallow; filter deep	750,000	457,750	1,244	760
Zero discharge; all	2,179,580	1,718,310	3,619	2,853

BOE: barrel of oil equivalent.

Air emissions calculated for produced waters include particulates in addition to NO_x, CO_2, and SO_2. These are pollutants associated with gas turbine operation. Energy requirements for reinjection were based on an injection pressures of 1,800 psi and the energy derived from a natural gas turbine. An 80 percent motor efficiency and a 20 percent energy conversion efficiency were assumed. The same basis was used for the power requirements for the filtration option calculations, except pressurization to 50 psi was assumed.

2. Solid Waste Generation

The Agency evaluated the impacts of solid waste generation and disposal for the options considered in this rulemaking. The Agency concluded that there is adequate onshore capacity for the disposal of the amounts of drilling wastes (drilling fluids and cuttings) estimated to be generated by the preferred regulatory option (4 Mile; 1/1 deep). The following is a summary of the Agency's findings in this regard.

The regulatory options described in today's notice will not cause the generation of additional solids as a result of the treatment technology. However, some of the options—particularly those requiring zero discharge for drilling fluids and cuttings—would require disposal of the solids associated with waste materials. In particular, used drilling fluids and cuttings contain relatively high levels of solids, and considerable volumes are generated which would be disposed onshore under several of the regulatory options presented in today's notice.

For example, under the option requiring zero discharge of drilling wastes from all new offshore wells, EPA estimates that approximately 8.2 million barrels per year of drilling fluids and drill cuttings would be transported to shore for disposal. As indicated in Table 22, this zero discharge option represents the maximum amount of barged wastes required by any of the options considered in this rulemaking. This volume of barged wastes may be compared to the Agency's estimates of 361 million barrels per year of drilling wastes generated from the drilling of onshore wells, including 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 (hereinafter "Report to Congress"). The maximum barged volume of approximately 8.2 million barrels per year represents about 2.3 percent of the volume of all drilling wastes that are generated and disposed onshore. Likewise, Table 20 indicates that the Agency's preferred regulatory option (4 Mile; 1/1 deep) would require the transport of approximately 1.6 million barrels per year of drilling waste to shore for disposal. This represents less than 0.5 percent of the volume of all the drilling wastes that are generated and disposed onshore.

Those drilling wastes that are generated offshore and transported to shore for disposal under the preferred option would be deposited in land disposal units similar to those used to manage a portion of onshore-generated drilling wastes. These land disposal units would generally be located relatively near the coast where the wastes are brought to shore. While there are currently no federal requirements for the onshore disposal of drilling wastes under the RCRA (see EPA's "Regulatory Determination for Oil and Gas Geothermal Exploration, Development and Production Wastes" at 53 FR 25446), there are existing State program requirements in the Gulf Coast and California Coast areas where the wastes would be brought to shore. EPA is developing a tailored program for the management of exploration and production wastes under RCRA Subtitle D.

As discussed in Section XIV of today's notice, the Agency did study that availability of land disposal capacity for drilling wastes that would be transported to shore for disposal under the regulatory options presented in today's notice ("Onshore Disposal of Offshore Drilling Waste—Capacity and Cost of Onshore Disposal Facilities," ERC Environmental and Energy Services Co. for U.S. EPA, January 1991). That study concluded that there is at least 45 million barrels per year of available or projected land disposal capacity for drilling wastes beyond current requirements in the Gulf and California coastal areas (including those volumes of onshore-generated drilling wastes and those offshore-generated drilling wastes which are currently brought to shore for land disposal). The 1.6 million barrels per year of drilling wastes that would be disposed onshore under today's preferred option represents approximately 3.5 percent of the estimated available land disposal capacity in these coastal areas, which the Agency believes to be a reasonable use of the available capacity.

3. Underground Injection of Produced Water

In the Report to Congress, EPA analyzed the impact of the disposal of produced water in injection wells. The study found that injection wells used for the disposal of produced water have the potential to degrade fresh groundwater in the vicinity if they are inadequately designed, constructed, or operated. Highly mobile chloride ions can migrate into freshwater aquifers through corrosion holes in injection tubing, casing, and cement. The federal Underground Injection Control (UIC) program (administered by EPA and states pursuant to the Safe Drinking Water Act, sections 1421–1425) requries mechnical integrity testing of all Class II injection wells every 5 years. All states meet this requirement, although some states have requirements for more frequent testing.

Many states have primacy for the UIC program. Both the criteria used for passing or failing an integrity test for a Class II well and the testing procedure itself can vary. There is considerable variation in the actual construction of Class II wells in operation nationwide, both because many wells in operation today were constructed prior to the enactment of current programs and because current state programs vary significantly. State requirements for new injection wells can be quite extensive. However, state requirements for construction of injection wells prior to the enactment of the UIC program have evolved over time, and construction ranges from injection wells in which all groundwater zones are fully protected with casing and cementing to shallow injection wells with one casing string and little or no cement. Furthermore, the offshore areas which may be considered for reinjection at distances greater than 4 miles may not have freshwater aquifers in proximity to the injection formations.

B. Other Factors

The industry has argued that injuries and fatalities due to hauling additional volumes of drilling wastes to shore would increase. Based upon available information, it is likely that the number of accidents would increase if the volume of waste transported to shore increased. However, it is difficult to determine quantitatively the increase in accidents and fatalities.

XIX. Solicitation of Comments

The Agency invites and encourages comments on any aspect of these proposed regulations. The preceding parts of today's notice list specific areas where comments are solicited. Many of these areas and several additional areas open for comment are summarized below. In order for the Agency to evaluate views expressed by commenters, the comments should contain specific data, references, and information to support their views.

A. Industry Profile

The Agency believes that the estimated total capital costs and operation and maintenance costs for BAT produced water are valid even though the profiling effort does not include those structures currently producing in state offshore waters.[1] Peak and annual average water production rates are calculated for each model project, based on initial production rates, initial water cut, annual decline rates and the estimated economic lifetime of the model project. For each model project, peak water production rates were used in the development of capital costs, while average annual water production volumes were used to calculate operating and maintenance costs. The Minerals Management Service (MMS) reported the water production volumes for offshore federal waters in the year 1987 and state waters records reported water production volumes for state offshore waters for the year 1986. The Agency's estimate of average water production volumes in offshore federal water areas only exceeded the summation of the MMS and state records volumes reported by 60 percent. Since the Agency's water production volume did not exceed actual volumes, the capital costs and the operating and maintenance costs that were developed accounted for those structures in state waters that the Agency was unable to profile. However, because these costs are distributed over fewer structures, the impacts may be somewhat over-estimated.

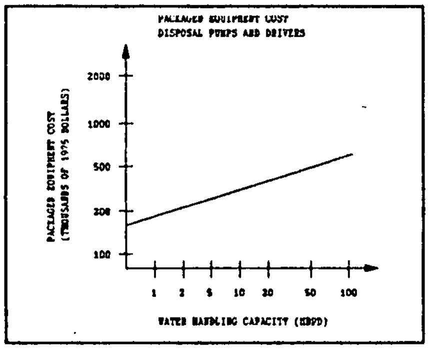
EPA welcomes comment, information and data concerning the number of structures currently in production in state offshore waters and their associated water production using the Agency's definition of "offshore."

B. Produced Water Treatment Costs

The Agency believes that today's proposal is based on produced water treatment costs that are substantially improved from those used in the 1985 proposal. The capital costs that were used for the 1985 proposal and have been used for today's proposal were costs supplied to the Agency by industry. These costs were contained in an October 1975 report entitled, "Potential Impact of EPA Guidelines for Produced Water Discharges from the Offshore and Coastal Oil and Gas Extraction Industry." This report was prepared by Brown and Root for the Sheen Technical Subcommittee of the Offshore Operators Committee. In this report, costs of equipment were plotted

[1] Drilling and production efforts in state waters are included in the evaluation of NSPS costs and impacts for drilling fluids, drill cuttings and produced water.

in graphs such as the example shown in Figure 1.



In 1982, a second report was prepared for EPA by Hydrotechnic Corporation entitled, "Cost Estimates for Systems to Treat Produced Water Discharges in the Offshore Gas and Oil Industry to Meet BAT and NSPS." The costs in this report were derived from the 1975 Brown and Root report as follows: for a given piece of equipment at a given capacity, the costs were read off of the charts contained in the report. The costs from the charts were adjusted to 1981 costs by applying an inflation factor to them.

Up until late October, 1989, the costs being used were the escalated 1981 costs from the Hydrotechnic report which were escalated once again to achieve 1986 costs. Comments from environmental groups such as the Natural Resources Defense Council indicated that the costs used by the Agency in the 1985 **Federal Register** were too high thereby making some of the more stringent options economically infeasible. However, no adjustments in costs were made in response to such comments.

Since late October 1989, the submitted data have been extensively corrected throughout the offshore oil and gas project. The equipment costs used in the 1985 proposal were high to begin with and have continually been inflated over the years. Some re-costing of equipment has been performed that has resulted in reduced capital costs and lowered operating and maintenance costs. An example of equipment re-costing is the pump and its associated piping for the disposal system. For a disposal system that has the capacity to handle 200 barrels of water per day. The following costs from the 1975 Brown and Root Report were used:

Pump	$946,000
Associated Piping	1,960,000
Total	$2,906,000

EPA consulted the Department of Energy, Energy Information Administration for updated equipment costs. The Energy Information Administration produces an annual report, entitled "Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations," which is a result of extensive information gathering from equipment manufacturers and suppliers. The same 200 barrels of water per day disposal system costed to be $2.9 million from the 1975 Brown and Root report was re-costed using the Energy Information Administration basis to be:

Pump and Associated Piping: $240,000.

This annual report updates costs on pumps and disposal systems for different produced water handling capacities. This re-costing effort resulted in reductions of up to 91 percent in the capital costs of these disposal systems.

Once the equipment was re-costed and the engineering errors were corrected, there was a dramatic reduction in the total capital costs of the produced water options. For example, the option of a zero discharge requirement for all structures had capital costs reduced by 61 percent and the operating and maintenance costs were reduced by 54 percent.

The Agency is interested in comment on the cost corrections explained above and also the costs associated with installing and operating membrane filtration systems. In particular, EPA requests information and data as to the various advantages and disadvantages of membrane systems relative to granular (or other) filtration systems and other produced water treatment methods, especially BPT. For example, do membrane or other systems have advantages in terms of platform space requirements, fitting into the configuration of other production and treatment components, maintenance requirements, or energy use.

C. Drilling Fluids and Drill Cuttings Treatment Costs

1. Discharge Volumes

For the 1988 Notice of Data Availability, the Agency used discharge volumes for drilling fluids and drill cuttings that were submitted in response to the 1985 proposal. These discharge volumes were contained in a February, 1986 report entitled "Water-based Drilling Fluids and Cuttings Disposal Option Survey," by Walk, Haydel and Associates. During the comment period on the 1988 notice, an updated report for discharge volumes entitled, "Water-based Drilling Fluids and Cuttings Disposal Study Update," (Walk, Haydel and Associates, November, 1988) was submitted to the Agency.

This study update contained results from the measurement of the discharge volumes of drilling fluids and cuttings from 15 wells in Mobile Bay. A comparison of the data from the updated study was made in relation to the data contained in the 1986 report.

The 1986 report contained discharge volumes of 1,430 barrels of cuttings and 5,349 barrels of drilling fluid (with an additional 1,400 barrels of fluid allocated to the active mud system) for a 10,000 foot well located in the Gulf of Mexico. These data were based on theoretical calculations used by most operators in estimating the volumes of drilling wastes reported in the Agency's Discharge Monitoring Reports.

After review of the 1988 study, the Agency believes for the reasons explained below that the data from the 1986 Walk, Haydel and Associates report provide better information for estimating typical discharge volumes of drilling fluids and cuttings from those reported in the 1988 study for U.S. offshore wells.

2. Well Depths and Formation Characteristics

For the purpose of costing options for drilling fluids and cuttings, the average well depth in the Gulf of Mexico was assumed by EPA to be 10,000 feet. In the updated study, all of the well depths were over 12,000 feet and over half of the wells went to depths of 20,000 feet. These 20,000-foot wells in the Mobile Bay area were most likely tapping the Norphlet formation which is a high temperature, high pressure and high sulphur environment. Chevron, USA, Inc. made a request of the Minerals Management Service to allow a delay in field delineation while developing a metallurgy technology compatible with the environment. Mobile Oil Corporation had to replace liners in Norphlet wells because of corrosion. The Norphlet formation has proven to be a difficult formation to produce from and therefore may be an equally difficult formation to drill. These wells are atypical of the majority of wells drilled and, therefore, the data from such wells do not realistically reflect the population of wells drilled in others formations.

3. Calculation of Discharge Volume Ratios

In the 1986 Walk Haydel report, the calculated discharge volume of drilling fluids and cuttings from an 18,000 foot well was 13,267 barrels. The actual volume from a 16,300 foot well (which industry considers to be similar to an 18,000 foot well) was measured to be 37,200 barrels. Industry then determined the ratio of the actual barrels discharged to the calculated barrels discharged to be 37,200/13,267=2.804. The "actual" volume of a 10,000 foot well was then determined by multiplying the calculated volume (1986) of 6,770 barrels by 2.804:

$6{,}779 \times 2.804 = 19{,}008$ barrels

This type of calculation assumes a direct linear correlation between well depth and discharge volumes of drilling fluids and cuttings. In 1985, the American Petroleum Institute surveyed 1 percent of the wells drilled onshore that year. It should be noted that the amount of drilling wastes from a given well are more likely to vary according to the depth of the well and the formation being drilled than whether the well is onshore or offshore. A regression analysis was run to fit the data obtained and the regression equations were used to extrapolate from the sample population to all onshore wells drilled in 1985. The 1986 report fit four regression models to the data, however, the model with the best fit was:

volume of waste$=a(\text{footage})+b(\text{footage}^2)+c$

This non-linear relationship can be attributed to several factors: Drilling rate; mud system change overs (each time a mud type is changed, the entire mud circulation system is changed as well); and mud type (larger quantities of mud are generated if low-density muds are diluted with water to maintain the solids concentration below a specified limit).

4. Valuation of Receiving Waters

As introduced in section XVI.C and discussed in section XVII of today's notice, the Agency is requesting comment on its approach to valuing marine waters. The monetized benefit values in the RIA primarily focus on human health effects. The RIA does not include monetized estimates of benefit parameters such as recreational uses or the intrinsic value of the resource. The Agency requests comment on the data and methodologies used in developing the benefit estimates presented in the Regulatory Impact Analysis.

D. Miscellaneous Discharges

EPA solicits additional information regarding the pollutant characteristics, sources, and treatment of deck drainage, produced sand, and well treatment, completion, and workover fluids. While EPA believes that its proposed treatment/control options for these sources are appropriate, the options are based on limited information. Additional data on pollutant loadings and quantity is solicited, as well as operational information on well treatment, workover and completion fluids including types of fluids, methods of injection and recovery, operational practices.

E. Industry Profile Within Three Miles

As discussed in section V.B, EPA evaluated regulatory options according to, among other criteria, distance from shore. The distances examined include 4, 6, and 8 miles from shore. EPA is also considering regulatory options based on 3 miles from shore. However, industry profile information is limited inside of 3 miles. EPA solicits information regarding numbers and types (i.e., gas only, oil only, gas and oil), and levels of production and waste discharges of oil and gas extraction producing facilities and projections or plans for new well drillings at 3 miles or less from shore.

F. Membrane Filtration Treatment Technology for Produced Waters

As discussed in section X.B, EPA is assessing the performance of membrane filtration on produced waters. EPA will be collecting sample data on tests performed at systems operating on offshore structures following this proposal. Analysis of these samples will include measurements of oil and grease exclusive of non-hydrocarbon organic materials. The Agency has recently received a petition from the OOC requesting review and revision of the oil and grease limitations for produced water based on the current analytical procedure not being appropriate. EPA requests additional comment or data on this subject. EPA is also soliciting any additional information on the performance of membrane filtration applications at any locations in the oil and gas industry and its applicability to treating oily waters.

G. Static Sheen Analytical Method

As discussed in section VII, the Agency is not changing the 1985 proposal which proposed the Static Sheen Test for determination of the presence of free oil. The method for this analysis was also proposed in that **Federal Register** notice. As further stated in section VII, there have been other analytical methods developed, that are in use, for the Static Sheen Test. In particular, the analyses developed by Region IX, and X, and another known as the "minimal volume method" are currently in use. These methods vary according to the volume of sample, the type of receiving medium (tap water, or sea water), mixing time, observation time, and determination criteria for the presence of free oil.

The Agency is soliciting comments on the 1985 proposed method and the other methods described with respect to their relative accuracy in identifying the presence of free oil.

H. Radioactivity of Produced Water

As also discussed in section VII, the Agency has conducted a literature and data gathering search regarding the presence and levels of radium in produced waters. Several studies on effluent or ambient levels of radium in areas surrounding offshore production sites are cited in section VII, although it was concluded that data bases are scattered and, for the most part, preliminary. EPA is soliciting comment and additional data concerning radioactivity of produced water, and its effect on ambient levels in the surrounding environment. Depending upon evaluation of additional data and comments submitted as a result of today's proposal, technologies such as ion exchange and types of membrane or other filtration suitable for removal of radioactivity may be considered as a technology basis for the treatment of produced water at promulgation.

I. Alaskan Waters

In section XII, EPA explained why it believes a zero discharge of drilling fluids and cuttings, based on barging of wastes, is not appropriate for offshore drilling operations in Alaskan waters. However, EPA is aware of an experimental operation to reinject drilling wastes. EPA solicits comments and information on the feasibility of requiring zero discharge based on reinjection, rather than barging of wastes to land for onshore disposal, for Alaskan waters.

J. Treatment/Control Options for Drilling Wastes

In section XIII, EPA lists and describes the BAT and NSPS options being considered for treatment and control of drilling wastes. EPA solicits comments on the preferred option (4 Mile Zero Discharge; 1/1 Beyond Option) and on the other options as well. EPA especially invites comment on the "5/3 All Structures" and the "1/1 All Structures" discharge options and on the "Zero Discharge All Structures" option.

K. Cadmium Formation Contribution to Drilling Wastes

In section XIII EPA describes an analysis of data from an API study on composition of drilling wastes. The analysis of these data estimates that 11 to 13 sites had higher concentrations of cadmium in their drilling fluids than in their barite. Certain assumptions are necessary in order to assign the increases in cadmium levels in the drilling fluids to sources other than the barite or to the formation being drilled. The assumption that cadmium is uniformly distributed throughout the barite and the drilling fluids must be made, the other components of the drilling fluid system do not contribute to this increase in cadmium levels, and that these sites are representative of the locations at future drilling will occur.

L. Treatment/Control Options for Produced Water

In section XIII EPA describes the BAT options being considered for treatment and control of produced waters. The types of control involve various combinations of treatment and discharge and/or zero discharge. The treatment and discharge technologies considered in the options described involve either BPT, filtration, or reinjection. Each option also varies according to requriements which may differ with respect to depth or distance from shore. EPA solicits comments on the viability and appropriateness of these options, especially with respect to the "Filtration All Structures," "BPT All Structures," and the "Zero Discharge" options. In addition, EPA solicits comment on the impact of produced water radioactivity on the viability and appropriateness of the proposed treatment options. EPA intends to issue a Notice of Data Availability and will take all available information into account in developing final regulatory controls on produced water.

M. Environmental Impact Analysis

Section XVII describes the environmental impact/benefit analyses performed by EPA on the proposed regulatory options for drilling wastes and produced waters. EPA believes that the water quality and cost/benefit analyses performed on both of these waste sources underestimates the benefits derived from the proposed regulations because only eight pollutants are used to represent average industry-wide discharges. These eight pollutants, according to EPA data, are those that are consistently present in significant levels. Some of the pollutants excluded from consideration were found in insignificant quantities or numbers of facilities. Yet, some of these pollutants are highly toxic. This analysis also does not consider impacts of various produced water additives, especially biocides, due to the lack of specific data on the use of these components. Thus, EPA solicits additional information on produced water and drilling waste characteristics, especially with respect to toxic pollutants, biocides, and use of other toxic additives. EPA also solicits information on the environmental impacts associated with these discharges.

XX. Variances and Modifications

A. Stormwater Variance

A concern not previously addressed is with respect to noncompliance with the deck drainage regulations because of storms. Rainwater comes in contact with the decks of the platforms and any open treatment or storage devices. Short-term, high volume loadings can temporarily interfere with treatment and control processes. One way to handle this is to require a certain size holding tank capable of containing stormwater associated with a certain size storm event until it can be routed to the treatment system, and allowing a variance for any overflows that may occur. Another method would be to allow a variance during the initial period (the "first flush") of the storm events and for a designated period after certain sized storm events.

EPA solicits comment on the appropriate approach to storm exemptions, especially regarding the appropriate size of storm events which would trigger a variance allowance, or the appropriate capacity of stormwater holding tanks.

EPA also solicits comment on Best Management Practices (BMPs) applicable to deck drainage. Such BMPs could, for example, require a regular washdown schedule where the drainage is sent through the major wastewater treatment system, thereby being subject to controls on produced water.

XXI. OMB Review

This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. Any written comments from OMB to EPA and any EPA responses to those comments are available for public inspection at the EPA Public Information Reference Unit listed in the **ADDRESSES** section of today's notice.

List of Subjects in 40 CFR Part 435

Oil and gas extraction, Waste treatment and disposal, Water pollution control.

Dated: February 28, 1991.

F. Henry Habicht,

Acting Administrator.

Appendices

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

Act—Clean Water Act.

Agency—U.S. Environmental Protection Agency.

API—American Petroleum Institute.

ASTM—American Society for Testing and Materials.

BAT—Best available technology economically achievable, under section 304(b)(2)(B) of the Act.

BCT—Best conventional pollutant control technology, under section 304(b)(4) of the Act.

BMP—Best Management practices.

BOD—Biochemical oxygen demand.

BPT—Best practicable control technology currently available, under section 304(b)(1) of the Act.

Bypass—An act of intentional noncompliance during which waste treatment facilities are circumvented because of an emergency situation.

Clean Water Act—The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et seq.), as amended by the Clean Water Act of 1977 and Water Quality Act of 1987.

LC50—The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay.

NPDES Permit—National Pollutant Discharge Elimination System permit issued under section 402 of the Act.

NRDC—Natural Resources Defense Council.

NSPS—New source performance standards under section 306 of the Act.

OCS—Outer Continental Shelf.

OOC—Offshore Operators Committee.

PESA—Petroleum Equipment Suppliers Association.

Priority Pollutants—The 65 pollutants and classes of pollutants declared toxic under section 307(a) of the Act.

RCRA—Resource Conservation and Recovery Act (Pub. L. 94-580) of 1976. Amendments to Solid Waste Disposal Act (42 U.S.C. 6901 et seq.).

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.

Appendix B—Major Documents Supporting the Proposed Reglulation

1. ERC Environmental and Energy Services Co. for EPA, "An Evaluation of Technical Exceptions for Brine Reinjection for the Offshore Oil and Gas Industry", January 1991.

2. Offshore Operators Committee, "Gulf of Mexico Spotting Fluid Survey", prepared by Exxon Production Research Company and Chevron, USA, Inc., April 4, 1987.

3. Offshore Operators Committee, "Final Report for Research Program on Organic Chemical Characterization of Diesel and Mineral Oils Used as Drilling Mud Additives—Phase II", prepared by Battelle New England Marine Research Laboratory, December 24, 1986.

4. EPA/API Diesel Pill Monitoring Program, presented at the 1988 International Conference on Drilling Wastes, Calgary, Alberta, Canada, April 5–8, 1988.

5. Science Applications International Corporation of EPA, "Summary of Data Relating to Minor Discharges", February 1991.

6. KRE, P.C. for EPA, "Offshore and Coastal Oil and Gas Extraction Industry Study of Onshore Disposal Facilities for Drilling Fluids and Drill Cuttings Located in the Proximity of the Gulf of Mexico", March 25, 1987.

7. KRE, P.C. for EPA, "Drilling Fluids and Drill Cuttings Disposal, Offshore Oil and Gas Extraction Industry", November 22, 1986.

8. ERC Environmental and Energy Services Co. for EPA, "Onshore Disposal of Offshore Drilling Waste—Capacity and Cost of Onshore Disposal Facilities", February 1991.

9. ERC Environmental and Energy Services Co. for EPA, "Review of Static Sheen Testing Procedures", January 1990.

10. American Petroleum Institute, "A National Survey on Naturally Occurring Radioactive Materials (NORM) in Petroleum Producing and Gas Processing Facilities", July 1989.

11. EPA, "Development Document for 1991 Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category", February 1991.

12. Walk, Haydel and Associates, "Water-based Drilling Fluids and Cuttings Disposal Study Update", January 1989.

13. Technical Resources, Inc., "The NPDES Drilling Fluids Toxicity Test Variability Study", February 1991.

14. EPA, "Economic Impact Analysis of Proposed Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry", February 1991.

15. EPA, "Cost-Effectiveness Analysis of Proposed Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry", February 1991.

16. EPA, "Regulatory Impact Analysis of the Effluent Guidelines Regulation for the Offshore Subcategory of the Oil and Gas Extraction Industry", February 19, 1991.

Appendix C.—Regulatory Boundaries

Structures discharging to the following areas shall be considered "shallow." Unless otherwise stated below, the outer boundary for each designated area is the 200-mile boundary of the Fishery Conservation Zone.

(A) Gulf of Mexico—Water Depth 20 Meters or Less

Extending from the inner boundary of the territorial seas of Eastern Texas, Louisiana, Mississippi, Alabama, and Eastern Florida.

(B) Atlantic Coast—Water Depth 20 Meters or Less

Extending from the inner boundary of the territorial seas offshore of the contiguous states between and including Maine and Florida.

(C) California Coast—Water Depth 50 Meters or Less

Central and Northern California: Extending offshore of California and bounded on the north by approximately 42° N. latitude and bounded on the south by the U.S.-Mexico boundary.

(D) Alaska

1. Gulf of Alaska—water depth 50 meters or less: It is bounded approximately on the west by 131° 55′ W. longitude, thence east along 58° N. latitude to 147° V. longitude, thence south.

2. Cook Inlet/Shelikof Strait—water depth 50 meters or less: Lies east of 156° W. longitude and north of 57° N. latitude to the inner boundary of the territorial seas near Kelgin Island.

3. Bristol Bay/Aleutian Range—water depth 50 meters or less: (a) North Aleutian Basin: Lies in the eastern Bering Sea northwest of the Alaskan Peninsula and south of 59° N. latitude. It is bounded on the west by 165° W. longitude and on the east by the inner boundary of the territorial seas.

(b) St. George Basin—water depth 50 meters or less: Lies in the eastern Bearing Sea northwest of the Aleutian Islands chain and is bounded on the north by 59° N. latitude and on the west by 174° W. longitude from 59° N. latitude to 56° N. latitude, thence east to 171° W. longitude, thence south. It is bounded on the east by 165° W. longitude.

4. Norton Basin—water depth 20 meters or less: Lies south and southwest of the Seward Peninsula. It is bounded on the south by 63° N. latitude, on the west by the U.S.-Russia Convention Line of 1867, on the north by 65° 34′ N. latitude, and on the east by the inner boundary of the territorial seas.

5. Beaufort Sea—water depth 10 meters or less: Lies offshore of Alaska in the Beaufort Sea and the Arctic Ocean. It is bounded on the west by the Mineral Management Service Chukchi Sea planning area, extends eastward to the limit of U.S. jurisdiction, and on the south by the inner boundary of the territorial seas.

To determine water depth at the facility location, reference that most recent nautical charts or bathymetric maps with the smallest scale (highest resolution) available from the National Oceanic and Atmospheric Administration for the area in question. Water depth is the mean lower low water depth indicated on the appropriate map for the location of the facility or discharge. Water depth at the facility is based upon the proposed location of the facility's well slot structure or produced water discharge point.

For the reasons set out in the preamble, title 40, part 435 of the Code of Federal Regulations is proposed to be 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: Secs. 301, 304, 306, 307, and 501, Public Law 92–500, 86 Stat. 816, Public Law 95–217, 91 Stat. 156, Public Law 100–4, 101 Stat. 7 (33 U.S.C. 1311, 1314, 1316, 1317, and 1361).

2. 40 CFR part 435, subpart A is proposed to be 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. This includes offshore facilities that transport wastes to onshore locations for treatment or disposal.

§ 435.11 Specialized definitions.

For the purpose of this subpart:

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

(b) 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-base 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-base drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase.

(c) 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.

(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 *produced water* shall refer to the water (brine) brought up from the hycarbon-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.

(f) 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.

(g) 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.

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

(i) 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.

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.

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

(l) 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 surfact of the receiving water, as determined by the Static Sheen Test.

(m) 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.

(n) 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.

(o) The term *96-hour LC50* shall mean the concentration of test material that is lethal to 50% of the test organisms in a bioassay after 96 hours of constant exposure.

(p) The term *exploration 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.

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

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

(s) The term *new source* means any exploratory, development or production facility or activity 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 consistent with the following definitions:

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

(2) The term *significant site preparation work* as used in 40 CFR 122.29 shall mean the process of surveying, clearing and preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site.

(t) The term *gas well* shall refer to any well that produces more than 15,000 cubic feet of natural gas for each barrel of produced petroleum liquids.

(u) The term *oil development and production facilities* shall mean those facilities subject to this subpart that are engaged in the development of or production from oil wells or oil and gas wells.

(v) The term *maximum for any one day* as applied to BPT and BCT effluent limitations 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.

(w) The term *maximum* as applied to BAT effluent limitations for drilling fluids and to NSPS for produced water and drilling fluids shall mean the maximum concentration allowed as measured in any single sample of the discharged waste stream.

(x) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids shall mean the minimum 96-hour LC50 value allowed as measured in any single sample of the discharged waste stream.

(y) The term *well completion fluids* means: Salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operation which prepare the drilled well for hydrocarbon production.

(z) The term *workover fluids* means: Salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures.

§ 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 125.30–125.32, 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:

Pollutant parameter waste source	BPT effluent limitations oil and grease mg/l		
	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 fluids	(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.
NA=Not applicable.

§ 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 125.30–125.32, 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):

Waste source	BAT effluent limitations	
	Pollutant parameter	BAT effluent limitation
Produced water:		
(A) For facilities located 4 miles offshore or less.	Oil and grease	The maximum for any one day shall not exceed 13 mg/l; the average of daily values for 30 consecutive days shall not exceed 7 mg/l.
(B) For facilities located more than 4 miles offshore.	Oil and grease	The maximum for any one day shall not exceed 72 mg/l; the average of daily values for 30 consecutive days shall not exceed 48 mg/l.
Drilling fluids and cuttings:		
(A) For facilities located 4 miles offshore or less.		No discharge.[1]
(B) For facilities located more than 4 miles offshore.	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3% by volume.
	Free oil	No discharge.[2]
	Diesel oil	No discharge in detectable amounts.
	Mercury	1 mg/kg dry weight maximum in the whole drilling fluid.
	Cadmium	1 mg/kg dry weight maximum in the whole drilling fluid.
Well treatment, completion and workover fluids.		Zero discharge of fluids slug plus 100-barrel buffer on either side.
Deck drainage during production:		
(A) For facilities located 4 miles offshore or less.	Oil and grease	The maximum for any one day shall not exceed 13 mg/l; the average of daily values for 30 consecutive days shall not exceed 7 mg/l.
(B) For facilities located more than 4 miles offshore.	Oil and grease	The maximum for any one day shall not exceed 72 mg/l; the average of daily values for 30 consecutive days shall not exceed 48 mg/l.
Deck drainage during drilling.	Free oil	No discharge.[1]
Produced sand		Zero discharge.
Sanitary MI0	None	
Sanitary M9IM	None	
Domestic waste	None	

[1] All Alaskan facilities are subject to the drilling fluids and cuttings discharge limitations for facilities located more than 4 miles offshore.
[2] Based on Static Sheen Test.

§ 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 125.30–125.32, 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):

Waste source	BCT effluent limitations	
	Pollutant parameter	BCT effluent limitation
Produced water (all structures)	Oil & grease	The maximum for any one day shall not exceed 72 mg/l; the average of daily values for 30 consecutive days shall not exceed 48 mg/l.
Drilling fluids and cuttings:		
(A) For facilities located 4 miles offshore or less		No discharge [1].
(B) For facilities located more than 4 miles offshore.	Free oil	No discharge [2].
Well treatment, completion and workover fluids	Free oil	No discharge [2].
Deck drainage	Free oil	No discharge [2].
Produced sand	Free oil	No discharge [2].
Sanitary M10	Residual chlorine	Minimum of 1 mg/l and maintained as close to this as possible.
Sanitary M9IM	Floating solids	No dishcarge.
Domestic waste	Floating solids	No discharge.

[1] All Alaskan facilities are subject to the drilling fluids and drill cuttings discharge limitations for facilities located more than 4 miles offshore.
[2] Based on the Static Sheen Test.

§ 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):

Waste source	NSPS effluent limitations	
	Pollutant parameter	NSPS effluent limitation
Produced water:		
(A) For facilities located 4 miles offshore or less	Oil & grease	The maximum for any one day shall not exceed 13 mg/l; the average of daily values for 30 consecutive days shall not exceed 7 mg/1.
(B) For facilities located more than 4 miles offshore.	Oil & grease	The maximum for any one day shall not exceed 72 mg/l; the average of daily values for 30 consecutive days shall not exceed 48 mg/l.
Drilling fluids and cuttings:		
(A) For facilities located 4 miles offshore or less		No discharge [1].
(B) For facilities located more than 4 miles offshore.	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3% by volume.
	Free oil	No discharge [2].
	Diesel oil	No discharge in detectable amounts.
	Mercury	1 mg/kg dry weight maximum in the whole drilling fluid.
	Cadmium	1 mg/kg dry weight maximum in the whole drilling fluid
Well treatment, completion and workover fluids		Zero discharge of fluids slug plus 100-barrel buffer on either side
Deck drainage during production:		
(A) For facilities located 4 miles offshore or less	Oil & grease	The maximum for any one day shall not exceed 13 mg/l; the average of daily values for 30 consecutive days shall not exceed 7 mg/l.
(B) For facilities located more than 4 miles offshore.	Oil & grease	The maximum for any one day shall not exceed 72 mg/l; the average of daily values for 30 consecutive days shall not exceed 48 mg/1.
Deck drainage during drilling	Free oil	No discharge [2].
Produced sand		Zero 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.

[1] All Alaskan facilities are subject to the drilling fluids and cuttings discharge limitations for facilities located more than 4 miles offshore.
[2] Based on Static Sheen Test.

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